GENERAL ATOMIC

ORNL/Sub/4188-1
(GA-A13406)

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PROCESS HEAT IN PETROLEUM REFINERY APPLICATIONS — FINAL REPORT —

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Prepared under
Subcontract No. 4188
for the OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37830
operated by
UNION CARBIDE CORPORATION
for the
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

GENERAL ATOMIC PROJECT 3237

DATE PUBLISHED: FEBRUARY 20, 1976

DISPATCHED TO THE NATIONAL BUREAU OF STANDARDS
128

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ABSTRACT

This report presents the results of a study conducted for the U.S. Energy Research and Development Administration, Oak Ridge National Laboratory, to evaluate the use of the General Atomic high-temperature gas-cooled reactor as a heat source for petroleum refining and other petrochemical processes requiring process temperatures up to 1050°F. The specific objective was to investigate methods of supplying and transporting steam and process heat from the primary reactor coolant to the refinery process heat exchangers. An evaluation of potential heat transfer fluids for transporting the heat from the reactor site to the refinery site was made and a promising fluid was selected for further investigation. A conceptual design of a secondary helium heat transfer loop with a heat exchanger located inside the prestressed concrete reactor vessel was established. Methods for providing minimum acceptable process heat and steam during reactor refueling and shutdown were investigated. A safety evaluation considering the possibility and consequences of radioactive contamination and petroleum contamination of the heat transfer fluid was conducted. The necessary modifications to the nuclear reactor system were identified and conceptual designs and economic estimates for these modifications were made. Areas where additional research and development may be required along with time and cost estimates for this effort were made. An estimate of plant availability for the system defined by the study was also made. Additional work was performed to develop a system to provide hydrogen as well as process heat for a crude oil refinery, a refinery handling low grade syncrude from oil shale, and a coal liquefaction plant.

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1. INTRODUCTION AND SUMMARY

At the request of Oak Ridge National Laboratory, a study was conducted to evaluate the use of the General Atomic high-temperature gas-cooled reactor (HTGR) as a heat source for petroleum refining and other petrochemical processes. The study investigated the technical and economic aspects of producing and transporting 1364 MW of thermal energy to a refinery, the boundary of which was located 3500 ft from the reactor. The refinery heat load was made up of 398 MW of 700°F steam and 966 MW of process heat having the capability of producing refinery process temperatures of 1050°F. The basic refinery heat balance is shown in Appendix A.

The heat source for the study was the HTGR, which is a thermal reactor utilizing helium as a coolant and having an all-ceramic core composed of thorium and uranium fuel with graphite as a moderator. While the HTGR is capable of producing considerably higher helium temperatures, it was found that a reactor outlet temperature of 1400°F was adequate for this study. This temperature is well within the limits of current HTGR core and thermal barrier designs.

In the commercial steam-producing HTGR, the major reactor system components such as the reactor core, control rod drive assemblies, helium circulators, steam generators, and core auxiliary cooling system are contained within a prestressed concrete reactor vessel (PCRV). For the heat transport study a 2000 MW(t) reactor was used. Two major modifications were made to the PCRV internals: (1) the steam generators were replaced by primary helium to secondary helium heat exchangers and (2) the number of primary reactor cooling loops was reduced from four to three.

The helium/helium heat exchangers located inside the PCRV are used to transfer heat from the primary reactor cooling loops to secondary or intermediate heat transfer loops. The reactor heat is then transferred to steam generators and to a fluid which transports heat to the refinery. A preliminary design of the secondary helium loop was established by this study.

A number of potential refinery heat transport fluids were investigated. A cost evaluation was made for each fluid considering the costs associated with heat exchangers, piping, insulation, pumping, heat loss, and fluid inventory. The lowest overall cost heat transport fluid was heat transfer salt (HTS), which is a eutectic mixture of potassium nitrate, sodium nitrite, and sodium nitrate. This fluid was selected for use in the remaining portions of the study, which included an investigation of the safety aspects of contamination by both radioactivity and petroleum.

Two basic approaches were investigated for providing a backup refinery heat source when the reactor is shut down. These were the use of a fossil fuel heater capable of supplying 67% of the refinery heat load and the use of dual 2000 MW(t) reactors. The single reactor configuration was limited to the case where the refinery steam requirement was generated at the refinery site while the dual reactor configuration considered generation of the refinery steam at both the reactor site and the refinery site.

An economic comparison of each of the reactor configurations was made by determining the cost of producing the required refinery heat. This cost analysis considered nuclear steam supply (NSS) and balance of plant (BOP) capitalized costs, operating and maintenance costs, nuclear and fossil fuel costs, and income from the sale of electrical power. Results showed that the dual reactor configurations were nearly the same cost, the system with refinery steam generated at the reactor site showing a slight advantage. The single reactor configuration cost was found to be either higher or lower than the dual reactor configurations depending upon the nuclear and fossil fuel cost, the selling price of electrical power, and the capitalization factor used to establish annual costs for the NSS and BOP. For a

nuclear fuel cost of $42\text{¢}/10^6$ Btu, a fossil fuel cost of $\$2/10^6$ Btu (oil at approximately $\$6/\text{barrel}$), an electrical power selling price of $15\text{¢}/\text{kw-hr}$ (July 1974 costs) and a fixed charge rate of 15%, the cost of the dual reactor configurations per million Btus of heat supplied to the refinery is approximately 24% lower than the single reactor configuration. If the fixed charge rate is increased to 25% with all other variables remaining the same, then the single reactor configuration cost is lower by approximately 6%. A sensitivity analysis showing the effect of process heat costs on fuel costs and electricity price is included in the report.

The study was completed by identifying areas where additional R&D is required and by estimating the process heat plant availability.

At the completion of the primary study discussed above it was requested by ORNL that the effort be extended to utilizing a 2000 MW(t) HTGR for the generation of process heat, hydrogen, and electricity for a crude oil refinery, a refinery handling low grade syncrude from oil shale, and a coal liquefaction plant. This study has shown the requirements to be as shown in Table 1-1.

The results of the study have indicated that an HTGR does provide a practical means for supplying heat to petroleum refineries and other petrochemical processes. The use of an intermediate helium loop to remove heat from the reactor coolant is practical, and HTS is a practical low-cost heat transport fluid for carrying heat to the refinery at temperatures up to 1100°F . However, a more extensive search for desirable heat transport fluids should be undertaken, particularly with regard to process heat systems at other temperature levels.

The selection of a means for providing a backup heat source is highly dependent upon nuclear and fossil fuel costs, electric power selling price, and the method used to capitalize the NSS and BOP costs. This study considered a dual reactor configuration and a single reactor with a fossil-fired backup heater. The costs of the backup systems have a significant impact on the process heat costs, and a more extensive investigation of

TABLE 1-1
REFINERY REQUIREMENTS

		Capacity (bbl/sd)	Hydrogen Requirements (scf/bbl)	Process Heat Requirements (MMBtu/bbl)	Hydrogen Prod. Energy (MW)	Process Heat (MW)	Excess Power [MW(e)]	Losses to Cooling Water, etc (MW)
Crude-oil refinery	A ^(a)	216,600	450	0.447	187	1182	796	1835
	B ^(b)	216,600	450	0.447	187	1182	112	519
Coal liquefaction facility	A	173,950	4346	33 kwh/t ^(c)	1406	75 ^(c)	683	1835
	B	173,950	4346	33 kwh/t ^(c)	1406	75 ^(c)	0	519
Oil shale liquids refinery	A	155,200	1981	0.447	540	847	778	1835
	B	155,200	1981	0.447	540	847	94	519

For twin 2000 MW(t) plants

(a) A - Both plants in operation

(b) B - One plant in operation

(c) Electrical load for coal plant (crushing and grinding)

this area would be worthwhile. A particularly attractive possibility would be to employ a molten salt heat storage system to provide for electric power for peaking purposes. This could significantly increase the revenue from the sale of excess electric power from the backup heat source, since this type of availability normally justifies higher selling costs.

2. CYCLE ANALYSIS

The initial step in the heat transport study was the definition of cycles that would satisfy the basic ground rules of the study. The goal of the cycle analysis was to define minimum cost systems that were within the current state of the art. Whenever possible, component designs that were similar or identical to existing designs were used. It was also found desirable to design for high electrical power output and a minimum of control problems.

The basic ground rules of the study that were applicable to the cycle definition were:

1. A heat generation and transport system was to be defined for the purpose of supplying a refinery with (1) 1165×10^6 lb/hr of 575 psig, 700°F steam and (2) 3296×10^6 Btu/hr of process heat with a supply temperature of 1100°F and a return temperature of 625°F.
2. Two basic configurations were to be considered:
 - a. One 2000 MW(t) HTGR with a fossil fuel backup capable of providing 67% of the refinery heat load. The fossil fuel heater, which was a part of the heat transport loop, was to be located at the refinery. The fossil fuel heater was to be on line at 25% of its maximum capacity at all times.
 - b. Two 2000 MW(t) HTGRs with electrical generating facilities for excess capacity.

Configuration (a) was to be designed for production of the refinery steam at the refinery site while Configuration (b) was to consider production of the refinery steam at both the reactor site and the refinery site.

3. The system was to use an intermediate helium heat transport loop to remove the heat from the reactor cooling loop and transfer it to the steam generation and refinery heat transport loops.

The basic approach to establishing the cycle configuration and its operating conditions was to define first the reactor and its cooling loop, then the secondary helium loop and, finally, the steam generation and heat transport loops. The primary cooling loop was the same for both basic system configurations. The core coolant flow rate and inlet and outlet conditions were selected so as to be compatible with the current 2000 MW(t) HTGR design. The reactor outlet temperature of 1400°F is well within the capabilities of the GA 2000 MW(t) core design.

The secondary helium loop design parameters were based upon previous GA work on this type of configuration known as the "MAXI" loop. "MAXI" loop refers to the configuration in which the entire reactor heat is transferred to a secondary helium loop through a heat exchanger located inside the PCRV with any required steam generation taking place outside the PCRV. The helium/helium heat exchanger, its flow rate and inlet and outlet conditions, and the secondary loop circulation design are the same for both basic system configurations.

The steam loop or loops were defined by first establishing the condenser conditions and then determining the flow rates and pressure-temperature conditions that would (1) remove the required heat from the secondary helium loop, (2) produce high electrical power output, (3) produce acceptable pinch points in the heat exchangers, (4) produce the necessary power for circulator and pump drives, and, when required, (5) produce the steam to be used by the refinery.

For the single reactor configuration, a single steam loop was defined to meet the above objectives. This single steam loop receives approximately 870 MW(t), which is sufficient to produce steam for pump and circulator drives and a moderate amount of electrical power.

With a dual reactor configuration, which must be capable of producing the full refinery heat load when one reactor is shut down, the selection of a steam loop configuration is somewhat more involved because the amount of heat available for producing steam is dependent upon whether one or both reactors are operating.

In order to fully utilize the available heat on both dual and single reactor operation, it was necessary to add an additional steam loop to each reactor system. This secondary steam loop is used only for the production of electrical power and, when required, the generation of steam for the refinery.

The condenser pressure and temperature of 1.1 psia and 105°F, respectively, were used for all steam loops. These values are identical to those used by HTGR steam plants.

The reactor cooling loop is identical for the three cycle configurations. The 2000 MW(t) reactor core is cooled by three helium loops. Each loop has a steam-turbine-driven helium circulator. The reactor heat is transferred from the primary helium loops to the secondary helium loops by three single-pass heat exchangers. The reactor core along with the primary cooling loops, the primary circulators, and the helium/helium heat exchangers are located inside a PCRV. With the exception of the helium/helium heat exchangers, the design of the primary cooling loops is similar to the HTGR steam plant. Figure 2-1 shows a schematic of the primary cooling loop. The flow rates, heat loads, and circulator powers shown are total for three loops.

Fig. 2-1. Reactor cooling circuit (typical all cycles)

2.1 SINGLE REACTOR WITH FOSSIL FUEL BACKUP

A flow schematic of the single reactor configuration is shown in Fig. 2-2. The fossil fuel heater, which is a part of the heat transport loop, is located at the refinery site. The heater has the capacity to provide 67% of the refinery heat load; i.e., 914 MW(t). When the reactor is operating, the fossil fuel heater is on line at 25% of its design capacity; i.e., 228.5 MW(t).

The three secondary helium loops (shown as a single loop in Fig. 2-2) are each driven by a separate circulator. The flows from these three loops are mixed before entering the steam and heat transport loop heat exchangers. The secondary helium loop circulators are similar to those used in the primary helium loop.

The steam loop is used to produce electrical power and to produce steam for circulator and pump drive turbines. The turbine marked "X" in Fig. 2-2 is a high pressure stage used to drive the primary helium circulators. Here again, Fig. 2-2 shows a single turbine while there are actually three turbines arranged in parallel. The turbine marked "Y" in Fig. 2-2 is actually four turbines arranged in parallel and used to drive the secondary helium circulators and the boiler feed pump. The turbines marked "G1" and "G2" in Fig. 2-2 are high and low pressure stages of a single shaft power turbine. The steam loop condensate pump and heat transport loop are electrically driven.

The operation of the steam loop is similar to that of the HTGR steam plant. Water is pumped into a steam generator and super heater to produce high pressure steam. This high pressure steam is expanded through high pressure power and primary circulator drive turbines, passed through a reheater, and then expanded through low pressure power and secondary loop circulator drive turbines. The low pressure turbine discharge flow is passed through a condenser, a condensate pump, and a feedwater

Fig. 2-2. Single reactor with fossil fuel backup

heater/deaerator. The feedwater heater/deaerator is also supplied with steam extracted from the low pressure turbine.

A system heat balance is shown in Table 2-1.

2.2 DUAL REACTORS WITH STEAM GENERATED AT THE REFINERY

A flow schematic of the dual reactor with steam generated at the refinery is shown in Fig. 2-3. The configuration for one reactor only is shown. During normal operation, each reactor supplies 50% of the necessary energy to the heat transport loop; this case is discussed first. The reactor primary coolant and the secondary coolant loop conditions are the same as in the previously discussed case. The secondary loop, after being heated to 1300°F in the primary-to-secondary helium heat exchanger, splits into two parallel streams with 50% of the flow going to the process heater and 50% to a secondary steam loop equipped with a reheater-steam generator combination. This secondary steam loop generates 284 MW(e) of power.

The two 50% streams then recombine and flow to a reheater-steam generator combination in the primary steam loop. The primary steam loop provides the power to drive the primary and secondary helium circulators (marked "X" and "Y" respectively in Fig. 2-3) and supply additional power of 117 MW(e).

There are three primary and three secondary helium circulators but only one process heat exchanger and one set of primary and secondary steam loop heat exchangers.

Dual vs Single Reactor Operation

The secondary helium loop has a parallel flow path that divides the flow between the process heater and the secondary steam loop heat exchangers. When both reactors are operating, each reactor supplies half

TABLE 2-1
SYSTEM HEAT BALANCE
SINGLE REACTOR WITH FOSSIL FUEL BACKUP (Btu/hr x 10⁶)

Reactor power	6825.5
Primary circulator heat input	154.4
Primary helium loop heat loss	58.4
Secondary helium loop heat input	6921.5
Secondary circulator heat input	185.7
Secondary helium loop heat loss	34.1
Heat transport loop heat input (from helium)	3877.0
Fossil fuel heater heat input	779.9
HTS pump heat input	7.6
Heat transport loop heat loss	8.5
Refinery heat load	4656.0
Steam loop heat input	3196.1
Primary circulator turbine heat load	158.7
Secondary drive turbine heat load	201.8
Power turbine heat load (high and low pressure stages)	771.6
Condenser heat load	2077.2
Condensate pump heat input	2.2
Boiler feed pump heat input	10.4
Net electrical output	218.6 MW(e)

Fig. 2-3. Dual reactors - steam generated at refinery

of the process heat and the helium flow through each parallel flow branch is half of the total secondary helium loop flow. When one of the reactors is shut down, the operating reactor must supply the full refinery heat load. This is accomplished by shutting down the secondary steam loop and routing the entire secondary helium flow through the process heater. The flow control valves for dual/single reactor operation are shown in Fig. 2-3. The valve in series with the secondary steam loop heat exchangers is fully open for dual reactor operation and closed for single reactor operation. The valve in series with the process heater is partially closed for dual reactor operation in order to provide the proper helium flow split between the parallel branches and fully open for single reactor operation in order to minimize the secondary helium loop pressure drop.

The primary steam loop also has a parallel flow path that splits the steam flow between power turbine G1 and secondary drive turbine Y. The flow split between these parallel paths is also dependent upon whether one or both reactors are operating. When both reactors are operating, each reactor supplies half of the steam required to drive the process heat loop pump. When one of the reactors is shut down, the operating reactor must supply the entire steam flow required to drive the process heat loop pump. The steam flow through turbine Y is actually reduced when the other reactor is shut down because the increase in turbine power required to drive the process heat loop pump is more than offset by the flow reduction due to the shutting down of the secondary steam loop. Control of the Y turbine flow was assumed to be carried out by a valve in series with the turbine. See Fig. 2-3. This valve is fully open when both reactors are operating and partially closed when the other reactor is shut down.

Figure 2-3 also shows on-off valves in the heat transport loop for isolation of the process heater of a reactor system that is shut down.

A system heat balance is presented in Table 2-2.

TABLE 2-2
SYSTEM HEAT BALANCE
DUAL REACTORS WITH STEAM GENERATED AT REFINERY^(a)

Reactor power	13651.0
Primary circulator heat input	308.8
Primary helium loop heat loss	116.8
Secondary helium loop heat input	13843.0
Secondary circulator heat input	371.4
Secondary helium loop heat loss	68.2
Heat transport loop heat input (from helium)	4658.0
HTS pump heat input	7.6
Heat transport loop heat loss	9.6
Refinery heat load	4656.0
Primary steam loop heat input	4830.2
Primary circulator turbine heat load	317.5
Secondary drive turbine heat load	453.6
Primary steam loop power turbine heat load	815.6
Primary steam loop condenser heat load	3266.4
Primary steam loop condensate pump heat input	3.4
Primary steam loop boiler feed pump heat input	12.2
Secondary steam loop heat input	4658.0
Secondary steam loop power turbine heat load (high and low pressure stages)	1977.8
Secondary steam loop condenser heat load	2725.2
Secondary steam loop condensate pump heat load	3.7
Secondary steam loop boiler feed pump heat load	43.2
Net electrical output	799.8 MW(e)

^(a) All values are total for two reactor systems, Btu/hr x 10⁶

2.3 DUAL REACTORS WITH STEAM GENERATED AT THE REACTOR

A flow schematic for the dual reactor with steam generated at the reactor configuration is shown in Fig. 2-4. With two exceptions this cycle is identical to the dual reactor with steam generated at the refinery configuration: (1) the addition of a refinery steam loop and (2) the steam supply for the feedwater heater in the secondary steam loop is extracted from the primary steam loop power turbine.

The refinery steam is supplied from the boiler feedpump discharge of the primary steam loop and the reheater discharge of the secondary steam loop. These two flows are mixed to obtain the desired steam temperature. Water is returned to both primary and secondary steam loops at the condensate pump outlets.

Dual vs Single Reactor Operation

The secondary helium loop has a parallel flow path that divides the flow between the process heater and the secondary steam loop heat exchangers. Here again, each reactor system is capable of supplying half of the refinery process heat and steam when both reactors are operating and the full refinery process heat and steam requirement when the other reactor is shut down.

When both reactors are operating, 35.4% of the secondary helium loop flow passes through the process heat exchanger and the remaining 64.6% passes through the secondary steam loop heat exchangers. The secondary steam loop then produces power in turbines G2 and G3 (See Fig. 2-4), both of which drive the same generator. When one of the reactors is shut down, the secondary helium loop flow is controlled so that approximately 70.8% passes through the process heater and the remaining 29.2% passes through the secondary steam loop heat exchangers. The operation of the secondary steam loop is modified so that there is no steam flow through turbine G3, the condenser, and the condensate pump when the other reactor is shut down.

Fig. 2-4. Dual reactors - steam generated at the reactor

For the primary steam loop, the flow split between turbines Y and G1 and the amount of water tapped from the boiler feed pump discharge and sent to the refinery are also dependent upon whether one or both reactors are operating.

Flow control for dual/single reactor operation is carried out by a number of valves. See Fig. 2-4. The helium valve in the secondary steam loop branch of the secondary helium loop is fully open when both reactors are operating and partially closed when the other reactor is shut down. The helium valve in series with the process heater is partially closed when both reactors are operating and fully open when the other reactor is shut down. The steam valve in the primary steam loop is fully open when both reactors are operating and partially closed when the other reactor is shut down. The steam valve in the secondary steam loop is fully open when both reactors are operating and closed when the other reactor is shut down. The heat transport loop uses on-off valves to isolate the process heater of a reactor system which is shut down.

A system heat balance is presented in Table 2-3.

TABLE 2-3
SYSTEM HEAT BALANCE
DUAL REACTORS WITH STEAM GENERATED AT REACTOR^(a)

Reactor power	13651.0
Primary circulator heat input	308.8
Primary helium loop heat loss	116.8
Secondary helium loop heat input	13843.0
Secondary circulator heat input	371.4
Secondary helium loop heat loss	68.2
Heat transport loop heat input	3298.0
HTS pump heat input	5.4
Heat transport loop heat loss	7.4
Refinery process heat load	3296.0
Primary steam loop heat input	4830.2
Primary circulator turbine heat load	317.5
Secondary drive turbine heat load	462.5
Primary steam loop power turbine heat load	505.4
Primary steam loop condenser heat load	2484.6
Primary steam loop condensate pump heat input	2.6
Primary steam loop boiler feed pump heat input	11.6
Secondary steam loop heat input	6018.0
Secondary steam loop power turbine heat load (high and low pressure stage)	2386.2
Secondary steam loop condenser heat load	3401.2
Secondary steam loop condensate pump heat load	4.6
Secondary steam loop boiler feed pump heat load	55.8
Refinery steam loop heat loss	4.0
Refinery steam heat load	1360.0
Net electrical output	829.6 MW(e)

^(a) All values are total for two reactor systems, Btu/hr x 10⁶

3. HEAT TRANSPORT FLUID EVALUATION

The heat transport system must be capable of delivering large quantities of heat to a refinery, the boundary of which is located 3500 ft from the reactor. The amount of heat varies from 966 to 1364 MW(t) depending upon the cycle configuration. A single cycle configuration, i.e., dual reactors with steam generated at the refinery, was used to evaluate candidate heat transport fluids. This cycle uses two heat exchangers, one located at each reactor system, to transfer heat from the secondary helium loops to the heat transport fluid. When both reactors are operating, each process heater has a 682 MW(t) heat load. The heat exchangers are sized so that when one reactor is shut down the operating system can provide the full refinery heat load; i.e., 1364 MW(t).

The study ground rules specified that the heat transport fluid be supplied to the refinery at 1100°F and discharged from the refinery at 625°F.

The selection of a heat transport fluid was carried out by considering a number of candidate fluids; sizing piping systems for refinery supply and return; establishing piping pressure drops, heat losses, and required pumping powers; establishing helium to heat transport fluid heat exchanger designs; and, finally, establishing cost estimates for each of the systems.

3.1 CANDIDATE HEAT TRANSPORT FLUIDS

The selection of a heat transport fluid must be based on a number of considerations. The most important considerations are

1. The fluid must be thermally and physically stable within the applied temperature limits. It must not decompose or react chemically with the pipe material (corrosive).

2. The fluid must have a high volumetric specific heat in order to minimize the volumetric flow rate. This is necessary because a high flow rate will result in large diameters, high pressure drops and high inventories.
3. The fluid must have a low viscosity throughout the applied temperature range as high viscosity adversely affects the heat transfer characteristics and the pumping power.
4. Ideally the fluid should be compatible with air, water, and refinery fluids.
5. The fluid must result in an economical system.

As a result of a brief literature survey (Refs. 1-9) seven candidate heat transfer fluids were selected for evaluation.

As shown in Tables 3-1 and 3-2, each of the fluids has unique properties that make it a prime candidate for consideration in this study. These properties are discussed briefly below. For a more detailed discussion see Refs. 1-9.

3.1.1 Helium

Helium is a noble gas and is thermally stable and chemically inactive. It is the coolant in the secondary and primary coolant loop of the HTGR, which is used as the heat source in this study. Therefore, helium as the process heat transport fluid is compatible with these coolant loops and, being a noble gas, will also have little effect on refinery fluids. Moreover, an extensive design experience with helium systems exists at GA.

TABLE 3-1
CANDIDATE HEAT TRANSFER FLUIDS

	Advantages	Disadvantages
Helium	Chemical inactive Thermally stable Low viscosity Already used in primary and secondary coolant loops for HTGR	Expensive
Hydrogen	Thermally stable Good heat transfer properties Low viscosity Low pumping power Common fluid in refinery	Explosive with air May have adverse effects on steel at elevated temperatures
Nitrogen	Cheap Inert	Poor combination of heat transfer and flow properties High pumping power
Steam	Cheap Well known fluid	Corrosive
Carbon Dioxide	Cheap Used as reactor coolant High heat carrying capacity	Corrosive in presence of water Poor heat transfer High pumping power
Heat Transfer Salt (HTS)	High specific heat per unit volume High heat transfer coefficient Non fouling Cheap	High freezing point Relatively high viscosity Is at the limit of its thermal stability No internal insulation possible
Sodium Potassium Alloy (NaK)	Thermally stable High specific heat per unit volume Excellent heat transfer properties Low viscosity Low freezing point, high boiling point Low vapor pressure	Highly chemically active with air and water No internal insulation possible Corrosive above 932°F

TABLE 3-2
COMPARISON OF PROPERTIES OF HEAT TRANSPORT MEDIA

	Helium	Hydrogen	Nitrogen	Steam	Carbon Dioxide	Heat Transfer Salt	NaK
Density (lb/ft ³)	0.227/0.158 ^(a) at 667 psia	0.13/0.09 at 767 psia	1.44/1.00 at 597 psia	1.43/0.89 at 805 psia	1.2/0.78 at 496 psia	114.8/102.8	49.3/45.3
Heat capacity (Btu/lb-°F)	1.242/1.242	3.5/3.5	0.26/0.27	0.70/0.55	0.27/0.29	0.373/0.373	0.21/0.21
Thermal conductivity (Btu/hr-ft-°F)	0.14/0.18	0.19/0.25	0.027/0.035	0.029/0.062	0.019/0.038	0.33/0.33	14.6/14.5
Viscosity (cp)	0.031/0.039	0.0136/0.018	0.03/0.039	0.035/0.042	0.027/0.036	3.0/1.0	0.264/0.168
Chemical composition						KNO ₃ 53% NaNO ₂ 40% NaNO ₃ 7%	Na 22% K 78%
Comments						Melting point = 288°F; decomposes above 1100°F	Melting point = 10°F; boils at 1446°F

(a) At 625°F/at 1100°F.

3.1.2 Hydrogen

Hydrogen has very good heat transfer properties; its specific heat on a volumetric base is better than helium. Its low density and viscosity will result in low pumping power. Thermally it is very stable. It is a common fluid in refineries and it was therefore felt that its use would bring no unusual problems at the refinery.

Drawbacks are that it has very wide explosion limits with air and at these high temperatures may have adverse effects on the pipe construction material.

3.1.3 Nitrogen

Nitrogen was mainly chosen because of its cheapness and inertness. It has, however, a poor combination of heat transfer and flow properties.

3.1.4 Steam

Steam is the most common heat-transport medium. It is relatively cheap and used both at the refinery and in the power loops of the HTGR. However, at the high temperatures used here, corrosion may become a problem.

3.1.5 Carbon Dioxide

Carbon dioxide has the highest heat transport capacity of the gases discussed in Sections 3.1.1 through 3.1.4. It is relatively cheap and used as a primary coolant in a different type of gas-cooled nuclear reactor (e.g., Magnox). On the other hand it has poor heat transfer characteristics and will require high pumping power due to its high density and viscosity.

3.1.6 Heat Transfer Salt

Heat Transfer Salt (HTS) is a eutectic mixture of potassium nitrate, sodium nitrite, and sodium nitrate. It is cheap, does not foul the heat exchangers, and has very good heat transfer characteristics. Also, because of its high density compared with a gas, its heat transport capacity is much higher than for gases. For engineering purposes sufficient data are available. Disadvantages are its relatively high viscosity, and its high freezing point which will require steam tracing for startup and shutdown. And for this application it will be used up to its thermal stability limit. Internal insulation cannot be used, resulting in more expensive pipe material due to the higher pipe temperatures.

3.1.7 Sodium Potassium Mixture

A sodium potassium mixture (NaK) has excellent heat transfer properties, high specific heat per unit volume, and a low viscosity and low vapor pressure. Mixtures can be composed which have freezing points as low as 10°F. Also, because sodium and potassium are elements they are thermally stable. All of these properties make NaK very suitable as a heat transport mixture. It is, however, highly chemically active with water and air and at higher temperatures corrosion problems occur. Also, no internal insulation will be possible, resulting in more expensive pipe material.

3.2 REACTOR TO REFINERY PIPING SYSTEMS

A piping system, which would supply the heat transport fluid to the refinery and return it to the process heat exchangers at the reactor, was sized for the configuration utilizing dual reactors with steam generated at the refinery and a cost estimate was established for each of the candidate heat transport fluids. The flow rate for a given fluid was determined from the refinery heat load (4656×10^6 Btu/hr) and the fluid enthalpy or specific heat at the 1100°F refinery supply temperature and the 625°F refinery return temperature. The assumed piping configuration is shown in Fig. 3-1.

Fig. 3-1. Assumed Piping Configuration For Heat Transport Fluid Evaluation

The heat exchangers at the reactor and refinery were assumed to have a pressure drop of 5 psi each. The supply and return piping were each assumed to have a physical length of 7000 ft. For piping pressure drop calculations, the effective piping lengths were assumed to be twice the physical length in order to account for bends and other flow restrictions. The compressor or pump was assumed to be located at the process heat exchanger inlet. Friction factors for pressure loss calculations were for ordinary smooth steel pipe. Pump or circulator power was based upon an efficiency of 85%. Table 3-3 presents information on the pipe materials utilized in the study.

TABLE 3-3
PIPE MATERIALS FOR HEAT TRANSPORT FLUID EVALUATION

	Operating Temperature (°F)	Material	Allowable Stress (PSI)
Supply piping with no inside insula- tion	1100	A358 316 stainless steel 16CR-12Ni-2M	12,400
Supply piping with inside insulation	800	A155 low alloy/steel 1-1/2 Cr-1/2 Mo	17,200
Return piping with no inside insula- tion	625	A155 KC70 carbon steel	17,500

The cost penalties associated with the use of stainless steel pipe made the use of inside insulation desirable. This not only allowed the use of lower cost low alloy steel pipe, but also reduced the operating temperature and increased the allowable stress, which resulted in the use of thinner walls. Insulation on the outside of the pipe was also desirable in order to minimize heat loss. Heat transfer analyses indicated that, for the supply piping with gaseous fluids, the use of a 6-in. thickness of Kaowool insulation on the inside of the pipe and a 2-in. thickness of an insulation such as Johns-Manville Thermobestos on the outside of the pipe would result in an 800°F pipe wall temperature and a 200°F outside surface temperature. When the supply piping was transporting the high conductivity HTS or NaK, the use of inside insulation to reduce metal temperature was not effective and it was necessary to use stainless steel pipe. For these cases, 6 in. of outside insulation was used to produce an outside surface temperature of 155°F.

For the return piping, the fluid temperature was low enough that the use of inside insulation would not increase allowable stress values or allow the use of a lower cost material. An outside insulation thickness of 2 in. was used for all return piping. This produced an outside surface temperature of 170°F.

Pipe wall thickness was determined by using the maximum supply pressure for the supply pipe and the maximum return pressure for the suction pipe. A 15% safety factor was applied to the maximum pressure values.

Table 3-4 summarizes the piping system design data for the candidate heat transport fluids. It is seen that there are large variations in the design parameters. The pipe diameters and wall thicknesses and the pumping power requirements for each fluid were arrived at by selecting the pressure levels and flow velocities that resulted in minimum overall system cost.

Table 3-5 summarizes the system costs for the candidate heat transport fluids. Piping costs were dependent upon the heat transport fluid. For the gaseous fluids, the supply piping costs were based upon \$0.75/lb for the piping material, \$56/ft² for the inside insulation and \$1.40/ft² for the outside insulation. For HTS and NaK, the supply piping costs were based upon \$3.40/lb for the piping material and \$4.20/ft² for the outside insulation. The return piping costs were based upon \$0.55/lb for gaseous fluid piping, \$1.00/lb for HTS and NaK piping, and \$1.40/ft² for outside insulation. The pipe material costs included hydro and X-ray inspection and the inside insulation costs include installation. Pump and circulation costs were based upon \$100/hp. The cost of piping system heat losses was based upon \$1.00/million Btu which is \$58,400/million Btu/hr when capitalized over the life of the system. The unrecovered pump or circulator power loss cost was based upon an assumed loss equal to 10% of the pump or circulator power and the same \$58,400/million Btu/hr cost factor.

Table 3-5 shows that total piping system costs vary from 6.6 to 69.5 million dollars. The gaseous fluid systems are all much more costly than the HTS and NaK systems. This is due for the most part to higher piping costs because of the higher pressures and larger diameters required and higher pumping costs because of the low fluid densities.

TABLE 3-4
HEAT TRANSPORT FLUID PIPING SYSTEM DATA

	Helium	Hydrogen	Nitrogen	Carbon Dioxide	Steam	HTS	NaK
Flow rate, lb/hr x 10 ⁶	7.840	2.801	36.719	35.651	17.406	26.275	46.855
Inventory, lb	152,450	48,410	1,269,340	1,540,520	615,380	11,837,000	8,528,850
Supply pipe o.d. ^(a,b) , ft	10.07	7.862	11.75	11.23	8.758	3.747	4.746
Return pipe o.d. ^(a) , ft	9.85	7.199	11.22	10.85	8.299	3.788	4.533
Supply pipe velocity, ft/sec	250	275	135	110	140	11.0	25
Return pipe velocity, ft/sec	150	175	90	70	80	63	17.7
Pump or circulator inlet pressure, psia	622	721	533	438	723	40	40
Pump or circulator outlet pressure, psia	667	767	597	496	805	172	283
Pump or circulator power, MW(t)	108	65.2	122	79.8	71.5	1.93	146
Supply pipe wall thickness, in.	2.58	2.30	2.71	2.15	2.70	0.318	0.648
Return pipe wall thickness, in.	2.38	2.00	2.37	1.89	2.34	0.200	0.201
Piping heat loss, Btu/hr x 10 ⁶	39.6	30.3	46.1	44.4	34.0	10.3	13.4

(a) All cases: outer insulation thickness 2 in.

(b) For gases: internal insulation thickness 6 in.

TABLE 3-5
HEAT TRANSPORT FLUID PIPING SYSTEM COST DATA (MILLIONS OF \$)

	Helium	Hydrogen	Nitrogen	Carbon Dioxide	Steam	HTS	NaK
Supply piping	55.379	39.496	67.386	55.985	48.973	6.053	14.415
Return piping (incl. insulation)	28.883	18.044	32.939	26.180	23.908	2.152	2.607
Pumps or circulators	21.663	13.115	24.476	16.041	14.388	0.387	2.945
Inventory	0.865	0.047	0.027	--	0.004	1.776	13.646
Heat loss	2.311	1.773	2.693	2.595	1.983	0.601	0.783
Unrecovered pump or circulator power loss	2.146	1.299	2.425	1.589	1.425	0.038	0.291
Total piping system cost	111.247	73.774	129.946	102.390	90.681	11.007	34.687

The HTS piping system costs are also much less than the NaK costs. The major cause of this difference is in the fluid cost. HTS costs \$0.15/lb while NaK costs \$1.60/lb.

3.3 PROCESS HEAT EXCHANGERS

A preliminary analysis was performed to establish helium to heat transport fluid heat exchanger designs for each of the candidate fluids. The following assumptions were made for this analysis;

1. Straight, tube, and shell heat exchangers with secondary loop helium on the shell side and heat transport fluid on the tube side.
2. Common tube geometry.
3. Common frontal area.

The heat exchanger heat load and log mean temperature difference was the same for all cases. The heat exchanger heat transfer area was, therefore, a function of the overall heat transfer coefficient. The helium (shell) side heat transfer coefficient is the same for all cases. The heat transfer area is then a function of the heat transport fluid heat transfer coefficient. The computed heat exchanger heat transfer areas are presented in Table 3-6. NaK has the lowest heat transfer area because it has the highest heat transfer coefficient.

TABLE 3-6
PROCESS HEAT EXCHANGER HEAT TRANSFER AREAS (FT²)

He	H ₂	N ₂	CO ₂	H ₂ O	HTS	NaK
226,180	206,900	280,370	276,460	274,000	307,040 ^(a)	128,100

(a) Later analysis showed that by using a cross flow heat exchanger design for HTS the heat transfer area could be reduced to 180,000 ft² (see Section 4.3.3).

3.4 HEAT TRANSPORT FLUID SELECTION

The selection of a single heat transport fluid for use in the remaining portions of the study was made on the basis of cost. The cost for each fluid was made up of the piping system costs presented in Section 3.2 and the heat exchanger costs. It was found that the relative cost ranking of the candidate fluids shown in Table 3-5 was unchanged by the addition of the heat exchanger cost. This was found to be true for a wide range of assumed exchanger costs; i.e., \$15 to \$100 per square foot of heat transfer area.

Table 3-7 presents total system cost for each of the candidate heat transport fluids. These data are based upon a heat exchanger cost of \$20 per square foot of heat transfer area.

TABLE 3-7
HEAT TRANSPORT LOOP COSTS (\$ X 10⁶)

He	H ₂	N ₂	CO ₂	H ₂ O	HTS	NaK
64.623	45.099	23.605	60.057	53.426	12.797	28.217

The data in Table 3-7 show a significant cost advantage for HTS. HTS is by no means an ideal heat transport fluid for this application. The 1100°F operating temperature is at an upper limit beyond which excessive decomposition will occur. The 288°F melting temperature will require tracing of the heat transport loop piping. A process does exist, however, to add water to the HTS, as the temperature is lowered below its melting point, to avoid freezing problems. It was felt, however, that this process was impractical in a system this large. While the cost of this steam tracing was not included in the total cost shown in Table 3-7, it would not modify the selection of HTS as the heat transport fluid.

4. DESIGN ANALYSIS

4.1 REACTOR SYSTEM

The design of the reactor core, the core auxiliary cooling system, and the reactor control system is identical to that of the commercial HTGR steam plant. The reactor system components that differ in design from the steam plant are the helium cooling loops (three loops instead of four); the helium/helium heat exchangers, which replace the steam generators; the helium circulators, which are resized for higher helium flow rate and revised steam conditions; and the PCRV, which has fewer cavities due to the reduced number of cooling loops.

The reactor core is made up of 2744 hexagonally shaped fuel elements. Each element is approximately 14 in. across the flats and 31 in. high. The fuel, in the form of coated particles of uranium dicarbide as the fissile material and thorium oxide as the fertile material, is located in vertical blind holes in the fuel elements. Vertical coolant holes are provided for helium flow through the fuel elements. The fuel elements are stacked in columns eight elements high, so that the active core height is 20.8 ft. The core is made up of 343 columns, giving an active core mean diameter of 23.1 ft. The active core is divided into 55 refueling regions and is surrounded by graphite reflector elements. The entire assembly is mounted on a graphite block floor, which, in turn, is supported by graphite columns.

Each of the 55 fuel regions is composed of a central control fuel column surrounded by six columns of standard fuel elements, except at the core periphery where reflector columns replace some of the fuel columns.

Core heat removal is accomplished by the downward flow of the helium coolant through the fuel columns. Variable flow control valves in each refueling region help balance the coolant flow through the various core regions in proportion to region power production and thereby regulate the fuel temperatures in the core.

The bulk of the coolant passes down the coolant channels within the fuel element columns. The remaining part of the flow is divided nearly equally between the side reflector, the control rod channels, and the small clearances between individual fuel element columns in the active core. The performance parameters conform to a conservative core design in which the fuel and graphite temperatures are below design safety limits.

The reactor is controlled by means of 55 control rod pairs, a total of 110 control rods. Each pair of control rods is suspended by cables operated by a motor-driven rod drive mechanism. The control rods, which contain boron carbide, move in vertical channels in the central column of fuel elements in each region.

A reserve shutdown system is provided that releases neutron-absorbing pellets containing boron carbide into the core. The reserve shutdown system, which is independent of the normal reactor control system, provides a means of introducing negative reactivity into the core. This system is manually actuated in the unlikely event that the normal control rod system fails to function.

Neutron flux information for monitoring, protection, and control systems is supplied from neutron detectors located in wells in the PCRV wall outside the liner. In-reactor neutron detectors and thermocouples at each refueling region outlet provide additional information for flux monitoring and control.

Burnable poison in the form of graphite rods containing up to 5 wt % natural boron in the form of B_4C is used to control part of the core excess reactivity and to flatten the transverse core power distribution.

The fuel temperature coefficients and the isothermal temperature coefficient (sum of fuel and moderator coefficient) are negative for all fuel cycles and all normal and transient temperatures. The helium coolant has a positive but negligible reactivity worth due to its scattering properties. Thermalization of fast neutrons increases when the helium density increases; however, the pressure coefficient is negligible.

Fuel loading is based upon a 4-yr cycle; that is, approximately one-fourth of the core will be replaced on an annual basis. The initial fuel loading will consist of approximately 1149 kg of highly enriched uranium (93% U-235) and 26,100 kg of thorium.

As the U-235 is fissioned, fissionable material (U-233) is formed from the neutron capture by the thorium atoms. The U-233 which does not fission in situ may be recovered from the fuel during reprocessing and either sold or returned to the reactor. The average burnup at equilibrium is about 98,000 MWd/metric ton of uranium and thorium. Recycle of the U-233 is not planned during the initial years of core operation; however, eventual recycle of the accumulated U-233 is possible. Under recycle equilibrium conditions the fresh fuel will contain a new charge of U-235 and thorium plus reprocessed U-233.

The helium coolant transfers heat from the reactor core to the secondary coolant system. Helium is particularly desirable as a reactor coolant since it is chemically inert, is stable, has excellent heat transfer characteristics, and does not undergo phase change. The reactor coolant system contains three independent primary coolant loops, each having a helium circulator and a helium/helium heat exchanger. The design of the helium/helium heat exchangers is discussed in Section 5.3.1. Helium is circulated by means of steam-turbine-driven axial flow helium circulators. Flow is downward through the reactor core, upward through the helium/helium heat exchangers, and then back to the helium circulators. Each helium circulator is provided with a reactor coolant shutoff

valve whose purpose is to limit reverse coolant flow through a nonoperating loop. The design of the helium circulators is discussed in Section 4.4.

Since the coolant loops and their components are all located in cavities within the PCRV, the boundary for reactor coolant flow is provided by the PCRV cavity liners and the penetration liners and closures, while the PCRV itself provides the structural support to withstand the reactor coolant operating pressure.

The PCRV, which is housed within the reactor containment, is a multicavity pressure vessel that houses the reactor core, the reactor coolant system, and portions of the secondary coolant system.

The reactor core is located within a central cavity. The core cavity is surrounded by three heat exchanger cavities and two core auxiliary cooling loop cavities. Radial ducts at the top and bottom of the core cavity connect to these surrounding cavities.

The PCRV contains continuous internal steel liners which act as the reactor coolant flow boundary and sealing membrane. The PCRV provides the structural support for the pressure forces exerted by the reactor coolant. Thermal barriers (insulation) are attached to the inside of the liners, and cooling systems limit concrete and liner temperatures on the outside. The PCRV is constructed of high-strength concrete reinforced with bars and is prestressed vertically and circumferentially. The liner, concrete, reinforcing steels, and prestressing steels function as a composite structure. The PCRV is cast integrally with a support structure and reactor containment base mat.

PCRV overpressure is prevented by two 100% capacity relief valves. Effluent from the relief valves is discharged into the reactor containment.

Auxiliary systems are provided to perform functions necessary for operation, maintenance, and refueling of the station. These systems

include the helium purification system and radioactive gas recovery system.

The helium purification system removes radioactive material and chemical impurities from the reactor coolant system by continuously purifying a side stream of gas. The purified helium is used for purging helium circulator seals, control rod drives, instruments and valves, and PCRV penetrations. The purification system also purifies helium transferred from the reactor coolant system to the helium storage system during depressurization of the reactor for maintenance and/or refueling.

The radioactive gas recovery system processes radioactive gases collected by the radioactive gas waste system. Gases processed by this system are separated into two streams: (1) a concentrated stream containing radioactive noble gases and tritium, suitable for return to the reactor coolant system, and (2) residual gases that are returned to the radioactive gas waste system for processing.

Engineered safety features are included in the station design to provide for the mitigation of the consequences of postulated limiting or faulted conditions. These engineered safety features include the core auxiliary cooling system (CACS).

The CACS provides an independent means of cooling the reactor in the event that sufficient cooling capacity by the main cooling loops is not available. The two auxiliary cooling loops installed in the PCRV can also provide core cooling during station shutdown. They may be used if the main loops are out of service. Each independent auxiliary cooling loop consists of a motor-driven helium circulator, a water-cooled heat exchanger, and associated service systems. Heat is dissipated to the atmosphere by means of the air-cooled heat exchanger in the CACS.

Overall plant control is accomplished by an automatic load-following system from about 25% to 100% of rated load with minor operator action as needed.

The reactor monitoring system consists of the nuclear instrumentation for routine startup, automatic control, shutdown, and reactor protection, and an in-reactor system for monitoring core performance.

The nuclear instrumentation consists of three extended, wide-range logarithmic channels, three linear power channels, and an automatic neutron flux control channel. This instrumentation provides an indication of neutron flux level and rate of neutron flux change for routine startup and power operation of the reactor. It also provides the necessary trip outputs for alarms, interlocks, and reactor protection. Redundant instruments are provided in the reactor protection system.

The data acquisition and processing (DAP) system is a reliable dual computer-based instrumentation and processing system. Major functions of the DAP system are monitoring of inputs, performing extensive calculations on these inputs, notifying the operator of abnormal situations, and generating various displays and logs for use by operating personnel.

Fuel handling is conducted by utilizing specialized equipment that provides for safe, remote-controlled removal of spent fuel from the reactor, insertion of fresh fuel into the reactor, and storage of new and spent fuel.

Fuel handling is accomplished with the reactor shutdown and the reactor coolant system depressurized to slightly below atmospheric pressure. The fuel handling equipment and procedures are such that gas-tight integrity of the reactor coolant system and the fuel storage facilities is maintained at all times. Spent fuel is kept under a helium environment at temperatures below the normal service temperature. Shielding is provided to maintain personnel exposure in compliance with occupational standards.

Fuel handling equipment is moved and positioned by crane inside both the Reactor Containment Building and the Reactor Service Building

and is transferred between these buildings through the refueling access opening of the reactor containment by a rail-mounted transfer dolly.

The principal equipment used for fuel handling operations is:

1. A fuel handling machine removes and replaces fuel and reflector elements in the reactor. During refueling, the fuel handling machine, which is shielded and gas-tight, is placed over a refueling penetration in the PCRV. A fuel transfer mechanism within the machine travels down into the reactor cavity, picks up a fuel or reflector element, and carries it back into the machine for inspection.
2. A fuel transfer cask transports spent fuel and reflector elements between the fuel handling machine and fuel storage. Fuel is removed from the fuel handling machine and placed in the fuel transfer cask. The reactor containment crane places the transfer cask on the transfer dolly, which transports the cask to the Reactor Service Building. The Reactor Service Building crane is used to place the fuel transfer cask into the storage wells.
3. Reactor isolation valves provide shielding and sealing of refueling penetrations during the refueling operation. A reactor isolation valve connected to the refueling penetration serves as a radiation and atmospheric barrier when the control rod drive assembly is removed. Neither the fuel handling machine nor the auxiliary service cask is connected to that refueling penetration.
4. An auxiliary service cask is placed over the refueling penetrations to remove and install control rod drive and reserve shutdown assemblies before and after refueling. The auxiliary service cask is a gas-tight, shielded

containment equipped with a cable-suspended grappling device for handling of control assemblies.

5. A transfer dolly transports the fuel handling machine, auxiliary service cask, and fuel transfer casks between the reactor containment and the Reactor Service Building.
6. Fuel storage wells in the Reactor Service Building store spent fuel in a dry, inert helium atmosphere. External cooling coils surrounding the fuel storage wells circulate cooling water for dissipation of decay heat. The wells are designed to prevent criticality under any circumstance. They are gas-tight and water-tight.

After cooldown of the spent fuel, the fuel is transferred to a spent fuel sealing facility by means of the fuel transfer cask and the Reactor Service Building crane. In this facility, the fuel is placed in fuel storage cans, which are placed in shipping containers. The containers are sealed and leak tested in the sealing facility. The sealed shipping containers are then transferred to a temporary storage area in preparation for loading and shipment to the reprocessing plant.

The radioactive waste systems collect, process, and prepare for disposal anticipated and potentially radioactive wastes in a controlled and safe manner so that availability of the plant is not limited. Discharges comply with the allowable limits as established by 10CFR20 and the intent of the proposed Appendix I to 10CFR50 published in the Federal Register, June 13, 1971.

During normal operations only small quantities of liquid waste are generated at the station. These liquid wastes are collected, processed, and analyzed for compliance with governing regulations upon discharge. Liquid waste that is radioactive is processed for offsite disposal. Liquid waste that is generally free of radioactivity is sampled, processed, monitored, and then discharged into the cooling tower blowdown line if within applicable limits.

Releases from the radioactive gas waste system comply with governing regulations. Gas waste resulting from station operation, which is generally free of radioactivity, is processed through a process vent system where these gases are filtered, monitored, and then released to the atmosphere.

Gas waste resulting from a radioactive source is processed through the gas waste system and the gas recovery system. The gas waste system provides for the collection, compression, temporary storage, and testing of radioactive gases released from the station. The gas recovery system is a cyclic, dynamic, cryogenic absorption process. The low-temperature absorption systems recover and return helium to the reactor coolant, absorb and hold the radioactive gases on the charcoal beds, and release them in a controlled manner back to the PCRV cavity; they absorb and hold other gases (CO , N_2 , and O_2) that result from reactions and outgassing of graphite in the reaction core before releasing them to the gas waste system for subsequent release to the atmosphere.

During normal operation, only small quantities of solid waste are generated at the station. Production of solid waste arises from the replacement of titanium sponge in the hydrogen getter units. Solid waste also results from equipment being replaced through routine maintenance or by termination of equipment operation. Other solid waste results from the fixation of liquid radwaste designated for drumming. Solid waste is placed into containers, sealed, and shipped to an approved burial location for radioactive solid waste.

4.2. INTERMEDIATE HEAT TRANSFER LOOP

One of the study ground rules was that an intermediate helium loop would be used to remove the reactor heat from the primary helium loops and transfer it to the refinery transport and steam generation loops. The use of an intermediate helium loop isolates the steam and heat

transport loops from the primary reactor cooling loops. This greatly reduces the chances of radioactive contamination of the steam, heat transport fluid and steam, and heat transfer fluid, and petroleum contamination of the reactor coolant.

The pressure level in the intermediate loop was based upon the results of an earlier General Atomic study for this type of configuration. The maximum intermediate loop temperature of 1300°F was selected to provide a 100-degree approach on the helium/helium heat exchanger, a value that should produce a reasonable heat exchanger design. The minimum intermediate loop temperature of 550°F was based upon several considerations. A low minimum temperature is desirable in order to minimize the intermediate loop flow rate, but a high minimum temperature is desirable in order to produce high steam temperatures while avoiding heat exchanger pinch point problems. The 550°F value was selected after numerous iterations of the cycle balance.

The use of three intermediate loop helium circulators, one in each flow branch, makes it possible to shut down the individual branches.

Intermediate loop helium enters and exits from the bottom of the PCR.V. Isolation valves are provided on both sides of the reactor containment for each of the three flow branches (inlet and outlet).

Intermediate loop piping materials are carbon steel from the steam generator outlet (550°F) to the helium/helium heat exchanger inlet and low alloy steel for all other portions of the loop. All piping has outside insulation. The piping from the helium/helium heat exchanger outlet to the HTS heat exchanger (1300°F) also has insulation on the inside of the pipe. Without this inside insulation it would be necessary to use stainless steel pipe material. The inside insulation is similar to that of the hot ducts of the reactor cooling loops located inside the PCR.V.

The use of an intermediate loop requires additional helium storage facilities, circulation service equipment, helium purification equipment, and the necessary control and instrumentation equipment.

4.3. HEAT EXCHANGERS

4.3.1. Helium/Steam

All helium/steam heat exchanger designs are of the plain tubular counter flow type with helium as the shell-side fluid. This arrangement was chosen for the following reasons:

1. Lower shell-side pressure loops are inherent in axial-flow designs because turning losses and the higher friction losses associated with multipass crossflow designs are avoided; thus, circulator power requirements are minimized.
2. Because the shell-side flow is parallel to the tube bank, vortex-shedding-related tube vibration problems are minimized.
3. Thermal stresses are low compared to other arrangements because the fluid thermal gradients exist in the axial direction only.
4. Maximum utilization of the approach temperature difference is obtained with pure counter flow.
5. Plain tubular constrictions are not only conventional but also appear more compatible than other candidates (e.g., plate-fin) for the type of service, reliability, maintainability, and economics required.

A summary of pertinent design features for the heat exchangers is given in Table 4-1. Thermal sizing of these designs was accomplished by

TABLE 4-1
HELIUM/STEAM HEAT EXCHANGER DESIGN DATA

Description	Tube Pitch/Dia.	Tube O.D. (in.)	Tube Wall Thickness (in.)	No. of Tubes	Active Length (ft)	Frontal Area (ft ²)	HT Area, (ft ²)
Single reactor							
Steam generator	1.4	0.625	0.063	20,202	38	121.5	123,000
Reheater	1.8	1.0	0.1	4,234	23	82.5	25,000
Dual reactors (steam at refinery)							
Primary steam loop steam generator	1.6	0.625	0.063	18,290	34	110	101,500
Primary steam loop reheater	2.2	1.0	0.1	3,092	27.5	90	22,500
Secondary steam loop steam generator	1.8	0.5	0.025	9,238	19	45	23,000
Secondary steam loop reheater	2.2	1.0	0.05	1,580	16.5	46	6,500
Dual reactors (steam at reactor)							
Primary steam loop steam generator	1.6	0.625	0.063	18,290	34	110	101,500
Primary steam loop reheater	2.2	1.0	0.1	3,092	27.5	90	22,500
Secondary steam loop steam generator	1.8	0.5	0.025	9,238	19	45	23,000
Secondary steam loop reheater	2.2	1.0	0.05	1,580	16.5	46	6,500

first performing a computer survey to generate families of design solutions covering practical ranges of frontal area, tube diameter, and tube pitching. GENSIZ, an existing GA computer code, was used for this portion of the study. This program calculates the heat exchanger active length, surface area, and tube bundle friction losses that result for a given combination of operating conditions and the above geometric parameters. After the computer data were obtained, supplementary calculations were performed to account for the additional pressure losses associated with entrance and exit effects and the shell-side fluid drag past the tube supports. The processed results were then plotted to give the overall pressure losses, active length, and heat transfer surface area requirements as a function of heat exchanger frontal area for each case of tube pitch-to-diameter ratio, p/d , with a triangular pitch. An example of this type of tradeoff study is shown in Fig. 4-1. Using curves of this type, the heat exchangers were sized in accordance with the following criteria:

1. All of the allowable shell-side pressure loss was used.
2. Minimum frontal area solutions corresponding to tube diameters and pitching considered to be within practical bounds were selected in an effort to minimize costs by keeping the number of tube ends and heat exchanger shell and assembly costs relatively low.
3. Designs with low aspect ratios (length-to-diameter) deemed, by judgment, unacceptable for shell-side flow distribution were discarded. This area would be the subject of detailed flow distribution studies at the final stages.

Fig. 4-1. Design data for secondary steam loop steam generator, dual reactors with steam generated at refinery

4.3.2 Helium/Helium

The primary-to-secondary helium loop heat exchangers are also straight tube and shell counterflow designs. Primary design parameters are shown in Table 4-2. These parameters were selected in the same manner as those for the helium/steam heat exchanger (see Section 4.3.1).

TABLE 4-2
HELIUM/HELIUM HEAT EXCHANGER DESIGN DATA-
TRIANGULAR PITCH

Tube pitch/dia.	1.4
Tube o.d., in.	0.5
Tube wall thickness, in.	0.025
No. of tubes	24,000
Active tube length, ft	40
Frontal area, ft ²	100
Heat transfer area, ft ²	166,670

These heat exchangers use a mounting arrangement which has been under development at GA. This arrangement uses multiple semihemispherical headers at the hot and cold ends of the heat exchange tubes. The use of this type of header provides two major benefits: (1) a full span homogeneous tube field is achievable with shrouded modular construction and (2) stress problems normally associated with flat tube sheets are greatly reduced.

The first benefit is possible by virtue of the increased surface area to projected area available as compared with a flat tube sheet. This allows a tube module to be manufactured in a hexagonal pattern keeping the o.d. of the hemispherical header smaller than the distance across the bundle flats. Thus the same tube pitch can be maintained between tubes of adjacent modules as is held for tubes in the same module. This is not the case with flat module tube sheets, which must extend significantly beyond the tube bundle o.d. for tube sheet and header chamber support. The module therefore cannot be packed as close together as the spherical header modules due to header interference.

The latter benefit, reduced stresses in the spherical header, is inherent in this geometry due to the elimination of pressure-induced bending stresses present in a flat tube sheet. The spherical header experiences, instead, hoop and meridional stresses due to the fluid pressures. Therefore the header chamber and perforated shells can be made substantially thinner than a flat tube sheet in the same application.

The overall layout of the heat exchanger is a development which has been undergoing study at GA. In this application the heated fluid (the secondary loop helium) is introduced to a large center duct at the bottom end of the exchanger (Fig. 7-1). This duct passes the gas through the center of the assembly to a manifold at the top. Lead tubes welded to this manifold pass the "cold" helium to the 108 upper spherical headers. Each header has 217 tubes. The bottom ends of the tubes are also welded into spherical headers similar to those at the top. The upper lead tubes are provided with sufficient length to allow for the differential thermal expansion which will occur due to the difference in operating temperatures of the center duct and the heat transfer tubes. However, this problem is minimized by "tailoring" the heat transfer characteristics of the center duct by means of selective insulation. By insulating the inside of this duct while allowing hot primary loop helium to flow along the outside surface through special channels provided in the flow blockage seals around the pipe, higher average duct wall temperatures can be selected which will cause slightly greater thermal expansion in the center duct than in the module tubes. Thus the module tubes can be subjected to a low preselected tensile stress.

The lower spherical headers are connected through short, nonbinding lead tubes to collector headers, also of the spherical pattern, which in turn are connected to the main discharge ducts.

4.3.3 Helium/HTS

With the relatively very high density HTS (approximately 1000 times that of He) and with adequate pumping power available, it was felt that a cross flow heat exchanger would yield several advantages over the parallel counterflow configuration, such as compactness and better flow distribution. In addition, putting the HTS on the shell side at the specified 200 psi (approximately) eliminates a possible tube buckling problem since the helium pressure in the tubes is nominally 700 psi. A single tube size was investigated, having a 1.0 in. o.d. with a 0.1-in. wall thickness. This size is probably not too far from optimum when ΔP and tube field cost considerations are weighed against size and pressure shell cost. The pitch-diameter ratio was also fixed at 1.4 for the same reason.

The criteria used as a basis for the overall design were the tube side and shell side friction pressure drops. It was felt that reasonable flow distribution could be achieved with a tube side ΔP of 1.0 to 4.0 psi, and that shell side pumping power would not be excessive with a ΔP of up to 12 psi. Particular pressure drop values could, of course, be determined, but it would necessitate varying the tube size and/or pitch diameter ratio.

A double pass shell side flow path arrangement was used in order to avoid rather large thermal expansion differences between the first and last tubes in the line. Tube spacing geometry was also specified to be triangular.

The tube length and number of tubes were varied to influence the tube side ΔP and heat transfer film coefficient. On the shell side, the tube length, number of tubes and tube field depth to width ratio were varied to control the ΔP and film coefficient. The results of this iterative approach are shown in Table 4-3 for each of the cycle configurations. As can be seen, the tube field depth is generally two to three times the width. This convenient multiplier was somewhat forced so that the total heat exchanger could be broken into two or three sections, each having equal widths and

TABLE 4-3
HELIUM/HTS HEAT EXCHANGER DESIGN DATA

Cycle Configuration	Dual Reactors W/Steam Generated at Reactor	Dual Reactors W/Steam Generated at Refinery	Single Reactor W/Fossil Fuel Backup
Total power, Btu/hr	3297×10^6	4658×10^6	3877×10^6
Tube active length, ft	21.5	27.5	19.5
Tube bank depth, ft	21.75	29.75	21.75
Tube bank width, ft	10.86	9.9	10.86
Tube o.d., in.	1.0	1.0	1.0
Tube i.d., in.	0.8	0.8	0.8
Tube pitch, in.	1.4	1.4	1.4
No. of tubes	2×10^4	2.5×10^4	2×10^4
Heat transfer surface, ft ²	1.13×10^5	1.8×10^5	1.02×10^5
Flow area (shell, min), ft ²	33.33	39.0	33.33
Flow area (tube), ft ²	69.8	87.27	69.8
He temp in, °F	1293 ^(a)	1293 ^(a)	1300
He temp out, °F	820	802	889
HTS temp in, °F	626	626	626
HTS temp out, °F	1100	1100	1100
HTS press in, psi	200	200	~200
He press in, psi	700	700	700
HTS flow rate, lb/hr	18.6×10^6	26.275×10^6	21.874×10^6
He flow rate lb/hr	5.62×10^6	7.64×10^6	7.606×10^6
h (shell), Btu/hr ft ² °F	623	698	
h (tube), Btu/hr ft ² °F	290	302	
U (wall), Btu/hr ft ² °F	3700	3700	3700
U total, Btu/hr ft ² °F	188	199	
ΔT_m	157	129	205
ΔP shell friction, psi	5.0	9.4	8.41
ΔP tube friction, psi	2.1	3.2	3.5
D_H shell, ft	0.05	0.05	0.05
D_H tubes, ft	0.067	0.067	0.067
N_{Re} shell	6200	7486	
Total active tube length, ft	4.3×10^5	6.88×10^5	3.9×10^5
Total active tube vol, ft ³	844	1350	766
Total active tube weight, lb	4.38×10^5	7.0×10^5	3.9×10^5

^(a) Assumes all secondary loop heat losses occur at highest temperature level.

breadths. The widths were held to less than 11 ft so that the square tube field would fit in a round pressure vessel of shippable dimensions.

The basic mechanical design concept for the helium-to-heat-transfer-salt process heat exchanger is shown in Figs. 4-2 and 4-3. The heat exchanger is of the shell and tube type using straight tubes with cylindrical headers. Hot helium enters the heat exchanger at 1300°F and 700 psia, and leaves at 889°F. The heat transfer salt, which is double passed, enters at 626°F and 200 psia and exits at 1100°F. The extreme helium conditions require that the helium be inside the tubes with the lower pressure salt on the shell side. The straight tube was selected because it gives a large helium frontal area and because the design is rather conventional.

The heat exchanger is split into two shells, each 16 ft in diameter by 37 ft long. This split was made because the two shells better accommodate the geometry dictated by the pressure drop and frontal area requirements of the heat transfer analysis. As shown in Fig. 4-2, the hot helium enters through the top of the shells and is distributed to the individual header pipes, which connect to the modules. Each module is approximately 11 in. thick by 20 ft long by 12 ft wide. This thin modular design permits using cylindrical headers at the hot helium inlet where metal stresses and thicknesses are a severe design problem due to combined high temperature and pressure. At the cooler helium outlet, the header for each module is shown as being a flat tube sheet, which is practical at the lower temperature. This simplifies assembly and allows the use of tube sheet baffles and tube sheet spacers. By making the heat transfer salt side two pass, the average tube temperature throughout the heat exchanger is more nearly constant and differential expansion and thermal stresses are reduced. Tube sheet baffles are placed between the salt passes to separate the flow and are also placed near the upper tube ends to contain and direct the flow. The salt enters the lower side of the shell, flows across the tubes, and goes out the opposite side of the shell. It then flows similarly into the lower portion of the second shell and back across the upper portion of the shells as shown in Fig. 4-3.

Fig. 4-2. Process heat exchanger - helium to heat transfer salt

Fig. 4-3. Process heat exchanger - helium to heat transfer salt

4.3.4 HTS/Steam

The cycle configurations that provide for refinery steam generation at the refinery site have a straight tube and shell pure counterflow HTS/steam heat exchanger that is similar in design to the helium/steam heat exchangers. Design data for these heat exchangers are presented in Table 4-4.

TABLE 4-4
HTS/STEAM HEAT EXCHANGER DESIGN DATA

Tube pitch/dia.	1.4
Tube o.d., in.	1.0
Tube wall thickness, in.	0.1
No. of tubes	2500
Active tube length, ft	26.8
Frontal area, ft ²	29.5
Heat transfer area, ft ²	17,545

These heat exchangers have HTS on the shell side and steam on the tube side and have a triangular pitch.

4.4 CIRCULATORS

The process heat plant design uses existing HTGR steam plant technology. In the case of the helium circulators, the plant layout embodies the steam-driven helium compressor of the type used for the commercial 3000 MW(t) steam plant. In the process heat plant there are two turbomachines (excluding pumps and electrical generators), namely the primary loop circulator for transporting the helium in the reactor coolant loop, and the secondary or intermediate loop circulator.

By the very nature of the process heat plant less heat is available for producing steam to drive the circulators. So, compared with the HTGR, the turbine steam flows are reduced and the turbine enthalpy drops increased, the latter necessitating use of multistage axial flow turbines.

Thermodynamic conditions for the circulators are shown in Table 4-5. In this table, a comparison is made with the design data for the HTGR 3000 MW(t) circulators. Circulator preliminary design considerations are given in Table 4-6. These aerodynamic and mechanical design parameter limitations are representative of good design practice for high efficiency, long-life turbomachinery.

The primary loop helium circulators are installed above the heat exchangers in the PCRV vertical side wall cavities, and are used to provide the helium flow in the reactor primary system. Figure 4-4 shows that the circulator is rigidly mounted on an extension of the liner of the concrete closure. The compressor and drive turbine are mounted integrally on a single vertical shaft and overhung from a central bearing and seal housing that contains the water-lubricated bearings and seals. Helium enters the compressor from the annulus around the heat exchanger through an accelerating inlet section and is discharged into the chamber around the circulator after being decelerated in an annular diffuser. The helium flows into the core from this chamber formed by the circulator and the cavity.

With different operating conditions in the process heat plant, the thermodynamic conditions in the primary loop differ from the HTGR steam plant. Three primary loops were established [as opposed to six in the 3000 MW(t) HTGR], and from Table 4-4 it can be seen that this resulted in a considerably higher circulator mass flow rate.

An initial decision was made to keep the rotational speed (6750 rpm) the same as the HTGR circulator design since this has a strong impact on rotor dynamics, bearing loading and seals, etc. The first check on the design using the COMAX 1 code assumed the same mean blade speed (increased tip and reduced hub diameter to pass the higher mass flow) and axial gas velocity (540 ft/sec). This design was not acceptable because of high aerodynamic loading factor at the hub and high rotor centrifugal stresses because of the increased annulus area ($f_c \propto AN^2$).

Fig. 4-4. Steam turbine driven helium circulator for HTGR steam plant

TABLE 4-5
CIRCULATOR DESIGN DATA FOR HTGR HEAT PLANT (ORNL STUDY)

Unit	Primary Loop Circulator	Secondary Loop Circulator	3000 MW(t) HTGR Circulator for Comparison
Circulators/plant	3	3	6
Helium compressor type	Single-stage axial	Single-stage axial	Single-stage axial
Gas flow/unit, lb/sec	739.0	704.0	499.5
Inlet pressure, psia	707.0	681.0	680.5
Pressure rise, psi	18.0	26.0	19.5
Inlet temperature, °F	700.0	550.0	624.0
Steam turbine type	Multi-stage axial	Multi-stage axial	Single-stage axial
Steam flow/unit, lb/sec	146.6	83.0	358.9
Inlet pressure, psia	900.0	235.0	901.0
Outlet pressure, psia	285.0	20.0	666.0
Inlet temp, °F	750.0	800.0	703.7
Outlet temp, °F	507.0	340.0	635.0
Inlet enthalpy, Btu/lb	1363.7	1423.0	1334.0
Enthalpy drop, Btu/lb	100.3	213.0	27.60
Power/circulator, hp	21,500	25,000	14,000

TABLE 4-6
CIRCULATOR PRELIMINARY DESIGN CONSIDERATIONS

Aerodynamic Considerations

Turbine stage loading ($\Delta H/U_m^2$) = 1.5 - 2.0
Compressor diffusion factor $\dagger$ 0.52
Flow coefficient (v_a/U_m) $\dagger$ 0.40
Turbine rotor exit angle $\beta_2 \dagger 70^\circ$
Turbine exit KE ($WV_a^2/2g$) $\dagger$ 2-1/2% of turbine enthalpy drop
Specific speed-diameter to be in island of maximum efficiency
Total speed 6750 rpm as in HTGR circulator design

Mechanical Considerations

Compressor hub diameter 30.75 in. as in HTGR circulator
Turbine hub diameter 21.6 in. as in HTGR circulator
Turbine blade height $\dagger$ 0.50 in.
Blade tip speed $\dagger$ 1500 ft/sec
Centrifugal stress ($f_c \propto AN^2$) $\dagger$ 20,000 lb/in²

An acceptable design solution was realized by keeping the same hub diameter and allowing the axial velocity to increase (600 ft/sec) to minimize annulus area (and tip speed) increase. Details of this design are shown on Table 4-7. While further detailed analyses are required, the conceptual design shown has acceptable values of blade aerodynamic loading and stresses. The blade height is 6.625 in. compared with 5.125 in. in the steam plant HTGR circulator.

Another useful check on the validity of a conceptual turbomachine design is the specific speed-diameter relationship of the type shown in Fig. 4-5 (from Ref. 10) for axial flow compressors. The specific speed is a parameter of some significance in defining the general type of turbomachine design, because it is found that each class of machine has its maximum efficiency within a relatively restrictive range of specific speed. Initial calculations would be based on operating in the middle of the maximum efficiency island and then modifying the design as necessary to satisfy stress criteria, matching, and mechanical limitations, etc. From Fig. 4-5 it can be seen that the single stage conceptual primary loop helium circulator is in the right regime for high efficiency.

The horsepower requirement of the primary loop circulator is 21,500 compared with about 14,000 for the steam plant HTGR. As shown in Fig. 4-4 for the HTGR, the helium compressor is driven by a single-stage steam turbine. The steam turbine drives are designed to operate on cold reheat steam from the main turbine, saturated steam from the bypass flash tank, or steam from the auxiliary boiler. With the above series arrangement (with the main steam turbine), the circulator turbine is characterized by a high mass flow and relatively small enthalpy drop. From Fig. 4-4 it can be seen that steam enters from the upper penetration piping and flows downward through an annulus. The steam then accelerates through a radial annulus, turning 180 degrees prior to the nozzle inlet. It then expands through the nozzle ring and turbine blades, giving sufficient power to drive the helium compressor at the required helium flow rate and pressure. The steam discharges from the turbine blades into an annular diffuser

TABLE 4-7
DETAILS OF CONCEPTUAL PRIMARY AND SECONDARY LOOP
CIRCULATORS FOR HTGR PROCESS HEAT PLANT (ORNL STUDY)

Loop	Primary	Secondary	3000 MW(t) HTGR Circulator for Comparison
<u>Helium Compressor</u>			
Units per plan	3	3	6
No. of axial stages	1	1	1
Hub diameter, in.	30.75	30.75	30.75
Tip diameter, in.	44.0	44.0	41.0
Blade height, in.	6.625	6.625	5.125
Blading details	Rebladed HTGR	Rebladed HTGR	Report GADR-114
Rotational speed, rpm	6750	6750	6750
Pressure rise, psi	18.0	26.0	19.5
Loading ($\Delta H/U_m^2$)	0.41	0.50	0.45
Axial velocity, ft/sec	600.0	518.0	540.0
Flow coefficient, V_a/U	0.55	0.47	0.51
Specific speed, N_s	330	260	275
Specific diameter, D_s	0.70	0.77	0.80
<u>Steam Turbine</u>			
No. of axial stages	3	5	1
Hub diameter, in. (first/last)	21.6/21.6	21.6/21.6	21.6
Tip diameter, in. (first/last)	23.1/25.3	25.0/34.6	25.0
Blade height, in. (first/last)	0.75/1.85	1.7/6.5	1.7
Blading details	New design	New design	New design
Rotational speed, rpm	6750	6750	6750
Expansion ratio	3.16	11.75	1.35
Overall enthalpy drop, Btu/lb	100.3	213.0	27.6
Axial velocity, ft/sec	290.0	300/500	290
Loading ($\Delta H/U_m^2$)	1.92/1.75	2.25/1.56	1.47
Flow coefficient, V_a/U	0.44/0.42	0.44/0.60	0.42
Specific Speed, N_s	47	52/125	68
Specific Diameter, D_s	1.8	1.6/0.84	1.4
Max centrifugal stress, psi	4970.0	20,000.0	4820.0
Horsepower	21,500	25,000	14,000.0
Machine assembly length, ft	9.5	Further design work needed	9.5
Machine assembly diameter, ft	5.5	to define envelope	5.5

Fig. 4-5. Relationships between specific speed, specific diameter, and efficiency for axial flow compressors

where it is decelerated into a cylindrical pipe and discharged from the penetration at a low velocity.

In the process heat plant the lower steam flow and higher enthalpy drop have a significant effect on the primary loop steam turbine design. Since the performance of a turbine is limited by choking, it can be seen from Table 4-7 that the expansion ratio is in excess of the critical value and the enthalpy drop is almost four times the value of the HTGR design.

An initial scoping of the problem indicated that three axial stages would be necessary. Using the same rotational speed (6750 rpm) and the same hub diameter (21.6 in.) as the single-stage HTGR turbine, it was found that using acceptable values of flow coefficient (V_a/U) and stage loading ($\Delta H/U^2$) an acceptable design could be realized, but the inlet blade height would be 0.75 in. compared with 1.7 in. in the HTGR circulator. Although this is greater than the practical minimum allowable (0.50 in., from Table 4-6), small blade heights are of concern (tip clearance, secondary flows, and general end wall effects) and, while the aerodynamic loadings and stress levels are acceptable, some refinement on the blading design is necessary. Detailed stress analyses of the overall rotating assembly need to be performed to verify the validity of the overhung bearing concept with the increased weight (and inertia) of the three-stage turbine.

As mentioned in the previous section, the specific speed-diameter relations are a useful conceptual design tool, and a curve array (from Ref. 11) for axial flow turbines is shown in Fig. 4-5. It can be seen that the primary turbine parameters, while not really optimum, do lie in the region of high efficiency. Performance analyses of a large number of turbine rig tests produce an empirical relationship between stage loading factor ($\Delta H/U^2$), axial velocity/mean blade speed, and efficiency. Figure 4-6, constructed from tests from many different turbines (Ref. 12), shows this in a simplified form. The efficiency values shown in this figure do not include allowances for tip clearance and leakage losses, etc., but the position of the efficiency contours is not significantly changed by these factors.

Fig. 4-6. Relationships between specific speed, specific diameter, and efficiency for axial flow turbines

The secondary loop circulators, positioned outside the PCRv, provide the helium flow to transport heat from the reactor primary system to the secondary loop containing the process heat steam generators. Since they are not integrated in the PCRv, there is more flexibility regarding configuration and not such demanding envelope constraints. For the purpose of these conceptual design studies, however, the same type of configuration as the primary loop machine (Fig. 4-4) has been assumed. Details of the operating conditions are given in Table 4-5. Although the mass flow is slightly lower than the primary loop, the higher resistance in the secondary loop results in a higher pumping power. With a pressure rise of 26 psi (considered about the maximum for a single-state machine of reasonable efficiency), the power requirement is 25,000 hp.

The major assumptions made in the conceptual design analyses are the same as outlined for the primary loop compressor. It was found that the compressor could be rebladed within the same annulus as the primary loop unit and have acceptable aerodynamic loading and stress levels. Details of the design are shown on Table 4-7. While perhaps not fully optimized, it can be seen from the specific speed-diameter contours (Fig. 4-7) that the operating point is in the right region for high efficiency.

From Table 4-4 it can be seen that the operating conditions for this turbine are far removed from the HTGR steam plant design data. This secondary loop turbine is characterized by low flow and inlet pressure, large expansion ratio, and the attendant large enthalpy drop. Preliminary calculations indicated that five axial stages were necessary but a closer design evaluation might favor increasing this to six. Using the general design considerations from Table 4-6, it was found that the hub and tip diameters of the HTGR unit could be used for the first turbine stage. With an inlet blade height of 1.7 in. the axial velocity of 300 ft/sec is close to the HTGR value and, while the annulus dimensions are the same, new blade geometries are necessary because of the differing velocity triangles.

Fig. 4-7. Generalized axial turbine blading efficiency contours

With an expansion ratio of almost 12 and a low discharge pressure (20 psia), it was realized that the high specific volume of the steam at the last stage would require a large flow path area and give a flared annulus. From Table 4-6 it can be seen that two considerations affect the determination of exit annulus area: (1) mechanical limitation, in that a maximum value of centrifugal stress of 20,000 psi was considered reasonable, and this is proportional to annulus area times rotational speed squared; and (2) limit the leaving axial velocity so that the exit KE loss is no greater than about 2-1/2% of the turbine enthalpy drop. From Table 4-7 it can be seen that both of these requirements were met with an axial velocity of 500 ft/sec, resulting in a rear stage blade height of 6.5 in. This five-stage unit, while based on the same rotational speed and hub diameter as the HTGR single-stage turbine, really bears little similarity and should be designed to match the process heat plant requirements.

The conceptual design has acceptable aerodynamic and structural blading parameters, and from Fig. 4-5 it can be seen that the specific speeds and diameters for the first and last stages are generally in the right regime. From Fig. 4-6 it can be seen that the aerodynamic loading factor for the first stage is on the high side and, as mentioned earlier, a more favorable distribution of work could be realized by adding an additional stage. This was not evaluated since the design constraints of rotational speed (6750 rpm) and hub diameter (21.6 in.) would no longer apply if a new, more optimum machine were designed rather than compromising performance by considering modifications (rather major) to an existing circulator. The fact that the power level is almost twice that of the HTGR circulator turbine (same rotational speed) does introduce some uncertainty into the overall machine assembly with respect to rotor dynamics, bearing loading and seals, and general feasibility of the overhung rotor concept.

A conceptual sketch of a circulator arrangement established for an HTGR coal gasification plant is shown in Fig. 4-8. This sketch (included to show details of the machine assembly) is merely a modification of the HTGR design showing three, rather than one, steam stages. While the data

Fig. 4-8. Conceptual circulator machine assembly for HTGR coal gasification plant

on this sketch are applicable to another plant, the overall assembly of the unit is applicable to the process heat primary loop circulator.

4.5 HEAT TRANSPORT LOOP

The design of the refinery heat transport loop piping was carried out in a manner similar to that described in Section 3. The final design selection for each of the cycle configurations was more detailed, however, in that the minimum cost system included the effects of installation of the pipes, the costs associated with supporting and restraining the pipes, the cost of three 50% capacity HTS pumps, and the costs of the HTS valves required for pump and process heater isolation. The reactor and refinery heat exchanger pressure drops were increased from 5 to 20 psi each.

Installation costs included the transportation, placement, welding, X-raying and stress relieving of the pipes. A piping design and flexibility analysis computer program was used to establish expansion loop geometry and the required anchor and support locations. The time required to perform these complex flexibility analyses permitted the establishment of a reasonable but not necessarily minimum cost design. The high coefficient of expansion of the stainless steel supply piping made it necessary to place anchors at 250-ft intervals and use expansion loops such that the piping length was nearly 50% greater than the point-to-point transport length.

Support locations were established by examining the bending stresses due to the weight of the pipe and its fluid.

The supply and return piping materials were the same as those used in the heat transport fluid selection study. Table 4-8 summarizes the piping and insulation materials used.

TABLE 4-8
HEAT TRANSPORT LOOP MATERIALS

Description	Material	Specification	Comments
Supply piping	Austenitic stainless steel (Type 316)	ANSI: A-312	Welded pipe, 1100°F operation
Return piping	Carbon steel (Type 1030)	ANSI: A-155 Grade 70	Welded pipe, 625°F operation
External insulation	Thermobestos (hydrous calcium silicate/asbestos fibers)	Federal HH-1-523	Sectional pieces, 6 in. thick for supply piping, 2 in. thick for return piping

The criteria used to select supply and return pipe materials were low cost, state of the art materials, proven fabricability, field assembly experience, known environmental compatibility, and mechanical properties covered in applicable design codes.

The external pipe insulation was selected for its high strength, thermal stability, low cost, ease of application and repair, low conductivity, and proven environmental compatibility. Thermobestos is a standard external pipe insulation in high-temperature refinery applications (Ref. 13). References that investigated compatibility between HTS and containment materials were reviewed. No data were found that indicated any concern over the maximum operating conditions anticipated for the heat transport system under study.

HTS is oxidizing and promotes general corrosion of the ferrous alloys. However, corrosion studies have shown that corrosion rates are uniform and decrease with time (Refs. 9, 14-17). These results substantiate the formation of a tenacious, passive oxide film, which is desirable. Up to temperatures of 850°F, carbon steels have been successfully used with virtually no

corrosion. For higher temperature systems operating through 1100°F, stainless steels or heat resistant alloys are recommended by the supplier; they have shown improved resistance to general corrosion over carbon steels.

With a large system involving heat transport, the potential for mass transport of chemical species within the HTS is of concern. If elements are removed from the structural containment materials and redeposited or absorbed at different locations, design integrity could be impaired. This phenomenon would not be anticipated in an HTS system. The tenacious, passive oxide present on the metal surfaces should act as a very effective barrier to diffusion of interstitial elements like carbon. This prediction is in contrast to the one that must be made for systems containing sodium or NaK where the oxide layer does not exist above 932°F.

The environment external to the piping system will vary with site location, but typical refinery and/or sea coast atmospheric conditions probably represent the severest. The selected steels and insulation materials have performed very well at high temperature in the presence of these types of environments for a few decades. Table 4-9 briefly summarizes known data and history used for justifying the expectation of material/environmental compatibility for the HTS heat transport system. As is the case with any 316 stainless steel system, precautionary measures must be used to prevent inadvertent contact with stagnant water for long times. Pitting corrosion can occur under this type condition. In most refinery or other industrial operations using stainless steel systems, it is standard practice to dry and protect them following hydrotests or during down times when systems are not filled with the operating medium.

4.6 PLANT LAYOUT

A plant layout of the single reactor configuration is presented in Fig. 4-9. This layout was developed in order to investigate the integration of the secondary helium heat transfer loop and the refinery heat transport loop into an HTGR system.

TABLE 4-9
COMPATIBILITY OF MATERIALS WITH ANTICIPATED CHEMICAL ENVIRONMENTS

Material	Component	Justification of Compatibility	
		Internal (HTS)	External (Refinery or Sea Coast Atms)
Carbon- steel	Welded pipe at 650°F	<ol style="list-style-type: none"> 1. Virtually no corrosion to 850°F 2. Standard containment material for industrial heat treating tanks, heat exchangers 3. No history of nonuniform corrosion 	<ol style="list-style-type: none"> 1. Low general corrosion at 650°F < 0.002 in./10 yr 2. Conditions not conducive to material embrittlement, or nonuniform, accelerated corrosion
316-stain- less steel	Welded pipe at 1100°F	<ol style="list-style-type: none"> 1. Initial uniform corrosion at ~ 0.001 in/mo., decreasing as passive oxide develops; 0.1 in. thickness allowance for corrosion 2. Standard containment material for industrial applications between 850 - 1100°F 	<ol style="list-style-type: none"> 1. 400 - 1100°F: conditions not conducive to nonuniform, accelerated corrosion (i.e., pitting, crevice, or stress-corrosion) 2. A standard high-temperature pipe material for refinery applications at 1100°F 3. Precaution: material cannot tolerate stagnant water storage during downtimes or following hydrotest; susceptible to pitting.
Thermo- bestos	External insulation at 1100°F max.	<ol style="list-style-type: none"> 1. Thermally stable at 1200°F 2. Non-reactive with air and HTS. 3. Standard gasket and packing material in HTS pumping systems. 	<ol style="list-style-type: none"> 1. Nonreactive 2. Standard external pipe insulation in high temperature refinery applications

Fig. 4-9. Nuclear heat transport system - single reactor with fossil fuel backup configuration

The primary helium (core cooling) loops are not shown on the drawing. Secondary helium enters into and discharges from the bottom of the PCR. The secondary helium loop contains isolation valves on both sides of the reactor containment. Figure 4-9 shows the secondary loop circulators and the ducting that supplies turbine drive steam for both the primary and secondary loop circulators. The steam generator and reheater are located close to the turbine building to minimize steam piping runs.

Figure 4-9 shows a typical section of the refinery heat transport loop. Piping for the secondary helium heat transfer loop and the refinery heat transport loop are all above ground.

5. ECONOMICS

An economic evaluation of the three cycle configurations was made by developing and comparing the capital costs of each configuration. Capital costs for both the nuclear steam supply (NSS) and balance of plant (BOP) systems were developed. The BOP costs included the reactor to refinery heat transport system. All cost data were escalated to July 1, 1974.

5.1 NSS CAPITAL COSTS

The capital costs for the NSS were developed from information contained in Refs. 18 through 20. Reference 18 gives the NSS cost for a 3000 MW steam power plant, which was based on a recent bid to the Los Angeles Department of Water and Power (LADWP). The LADWP bid was adjusted to normal site conditions and normal contractual terms, as discussed in Ref. 20. Additional adjustments were made to scale the costs from a 3000 MW plant to a 2000 MW plant (Ref. 19), which resulted in a base NSS cost of \$109.3 M for unit 1 and \$101.5 M for unit 2.

The base NSS costs for the 2000 MW(t) steam plant were used to estimate the costs for the process heat system. Cost adjustments were made to the detailed NSS cost breakdown in Ref. 19 to reflect modifications required for the process heat system. These modifications included conversion from four to three helium loops and replacement of the steam generators with helium/helium heat exchangers. The resulting NSS costs for the process heat system are \$105.072 M for unit 1 and \$97.263 M for unit 2.

The components that make up the NSS system for the process heat plant along with the cost changes due to modification from a steam plant are presented in Table 5-1.

TABLE 5-1
NSS EQUIPMENT LIST AND COST DIFFERENCES

Description	Cost Change From Steam Plant (\$1000)
221 Reactor equipment PCRV support structure PCRV Precast panels Prestressing system Heat exchanger plugs Wire winding machine (lease) Thermal barrier PCRV liners & penetrations Reactor internals Reactor control system PCRV pressure relief system	-18.6
222 Main heat transfer and transport systems Circulators Circulation turbine admission & bypass valves Circulator service system Helium/helium heat exchangers	-4,242.4
223 Safeguards cooling systems Core auxiliary circulators Core auxiliary circulator controls Auxiliary circulator service system Core auxiliary cooling heat exchangers	0.0
224 Radioactive waste treatment & disposal systems Liquid waste processing equipment Gaseous waste & off-gas processing system Solid waste processing equipment	0.0

TABLE 5-1 (Continued)

Description		Cost Change From Steam Plant (\$1000)
225	Nuclear fuel handling & storage equipment	0.0
	Fuel handling tools & equipment	
	Fuel & reflector storage wells	
	Fuel handling purge & evacuation system	
226	Other reactor plant equipment	0.0
	Primary coolant purification system	
	Operator training	
910	Engineering, construction management, & field supervision	0.0

5.2 BOP CAPITAL COSTS

BOP capital costs were developed from each of the three cycle configurations. The primary basis for these costs was the detailed cost breakdown presented in Ref. 18. The costs in Ref. 18 were first escalated to July 1, 1974, using factors of 20% for equipment and materials and 12.5% for labor. The detailed costs were then adjusted to account for the specific design parameters of each of the three process heat plant configurations. Cost estimates for those components and systems which were not a part of the Ref. 2 costs were also developed. These systems included the secondary helium heat transfer loop and the refinery heat transport loop.

Tables 5-2, 5-3, and 5-4 present the BOP costs for the three process heat plant configurations. Table 5-5 shows how costs could be allocated to various portions of the system. Table 5-2 is for the single reactor with fossil fuel heater backup configuration. Tables 5-3 and 5-4 are for the dual reactor configurations with process steam generated at the refinery site and reactor site, respectively. The dual reactor configuration costs are total for both reactor systems.

5.3 ECONOMIC COMPARISON OF CYCLE CONFIGURATIONS

An overall cost comparison of the three cycle configurations was made by computing, for each configuration, the cost per million Btu's of heat delivered to the refinery. This overall refinery heat cost included capitalized NSS and BOP costs, operating and maintenance costs, nuclear fuel costs, income from the sale of electricity and, in the case of the single reactor with a fossil fuel heater, the cost of the fossil fuel. The costs were prepared using 90% plant availability for the nuclear reactor system.

Figures 5-1 through 5-4 present refinery heat costs for the three configurations as a function of the NSS and BOP cost capitalization factor, the cost of both nuclear and fossil fuel, and the selling price of the electrical power generated by the plant. Figures 5-1 and 5-2 are for a

TABLE 5-2
BOP COSTS - SINGLE REACTOR WITH
FOSSIL FUEL HEATER BACKUP CONFIGURATION

	Description	Cost (\$1000)
20	Land & land rights	1,000.0
211	Yard work	2,627.4
	General cut & fill	
	Roads, walks & parking areas	
	Fencing & gates	
	Sanitary sewage facilities	
	Yard drainage	
	Yard lighting	
	Railroads	
212	Reactor containment building & annulus electrical tower	20,429.3
	Substructure	
	Superstructure	
	Building services	
	Containment annulus	
	Annulus electrical tower	
213	Turbine generator building	3,022.5
	Substructure	
	Superstructure	
	Building services	
214	Intake structures	1,633.7
	Circulating water	
	Service water	
215	Reactor service building	12,476.0
	Substructure	
	Superstructure	
	Building services	

TABLE 5-2 (Continued)

Description		Cost (\$1000)
218A	Control building	4,448.9
	Substructure	
	Superstructure	
	Building services	
218B	Diesel generator building	3,557.3
	Substructure	
	Superstructure	
	Building services	
218C	Administration building	760.5
	Substructure	
	Superstructure	
	Building services	
218D	Turbine service building	1,141.9
	Substructure	
	Superstructure	
	Building services	
218E	Helium storage building	159.9
226	Other reactor plant equipment	11,353.9
	Coolant receiving, storage, & makeup systems	
	Nitrogen cooling system	
	Auxiliary cooling system	
	Decontamination system	
	Miscellaneous suspense items	
227	Instrumentation & control	
	Reactor & process instrumentation & control equipment	10,017.4
	Automatic monitoring & computing equipment	
	Monitoring systems	
	Isolated indicating & recording gauges, meters, & instruments	
	Control & instrumentation piping & tubing	

TABLE 5-2 (Continued)

Description		Cost (\$1000)
231	Turbine generators	8,186.9
	Turbine-generators & accessories 7,684,340	
	Foundation & supports 454,262	
	Generator cooling equipment 48,341	
232	Circulating water system	2,948.0
	Water intake facilities	
	Pumps & drives	
	Intake & discharge lines	
	Warming line	
	Discharge tunnel	
	Discharge canal	
233	Condensing systems	3,836.1
	Condensers	
	Condensate system	
	Turbine bypass system	
234	Feedwater system	5,562.7
	Feedwater heaters	
	Feedwater pumps	
	Piping	
235	Other turbine plant equipment	10,430.7
	Main vapor piping	
	Turbine auxiliaries	
	Auxiliary cooling system	
	Make-up treatment system	
	Chemical treatment system	
	Lubricating oil system	
	Miscellaneous suspense items	
236	Instrumentation & control	1,316.7
	Process instrumentation & control equipment	
	Automatic monitoring & control equipment	

TABLE 5-2 (Continued)

Description	Cost (\$1000)
Process monitoring systems equipment Isolated indicating & recording gauges, meters, & instruments Piping & tubing	
222B Secondary helium heat transfer loop Circulators Circulator turbine admission & bypass valves Circulator service system Helium purification system Process heater Steam generator Reheater Piping, valves, insulation, installation	13,328.5
222C Refinery heat transport loop HTS pumps HTS inventory Steam generator Piping, insulation, valves, supports, anchors, & installation	9,666.2
222D Fossil fuel heater	64,000.0
241 Switchgear Generator equipment Station service	2,048.3
242 Station service equipment Startup transformers Low voltage unit substations & lighting transformers Auxiliary power sources	4,131.8

TABLE 5-2 (Continued)

	Description	Cost (\$1000)
243	Switchboards	913.6
	Main control board for electric systems	
	Auxiliary power & signal boards	
244	Protective equipment	381.0
	General station grounding system	
	Fire protection systems	
245	Electrical structures & wiring	4,550.0
	Containers	
	Underground duct runs	
	Cable trays	
	Conduit	
	Other structures	
246	Power & control wiring	10,227.4
	Generator circuits wiring	
	Station service power wiring	
	Control wiring	
	Instrumentation wiring	
	Containment penetrations	
251	Transportation & lifting equipment	1,155.7
252	Air, hydraulic, water, & steam systems	4,201.6
	Service systems	
	Air systems	
	Water systems	
	Auxiliary heating steam system	
	Hydraulic power system	
253	Communications equipment	181.3
	Local communications systems	
	Signal systems	

TABLE 5-2 (Continued)

Description		Cost (\$1000)
254	Furnishings & fixtures	386.1
	Safety equipment	
	Shop, laboratory, & test equipment	
	Office equipment & furnishings	
	Change room equipment	
	Dining facilities	
910	Engineering, construction management, & field supervision	39,269.2
911	Temporary facilities	5,175.0
912	Construction equipment	9,300.0
913	Construction services	5,355.0
	Other undistributed costs	4,920.0
	Spare parts	
	Owner general office & administrative cost	
Total BOP cost		284,100.5

TABLE 5-3
BOP COSTS - DUAL REACTOR WITH
STEAM GENERATED AT THE REFINERY CONFIGURATION

	Description	Cost (\$1000)
20	Land & land rights	1,500.0
211	Yard work	3,941.1
	General cut & fill	
	Roads, walks, & parking areas	
	Fencing & gates	
	Sanitary sewage facilities	
	Yard drainage	
	Yard lighting	
	Railroads	
212	Reactor containment building & annulus electrical tower (2)	40,858.6
	Substructure	
	Superstructure	
	Building services	
	Containment annulus	
	Annulus electrical tower	
213	Turbine generator building (2)	9,159.4
	Substructure	
	Superstructure	
	Building services	
214	Intake structures	4,438.5
	Circulating water	
	Service water	
215	Reactor service building	20,793.3
	Substructure	
	Superstructure	
	Building services	

TABLE 5-3 (Continued)

Description		Cost (\$1000)
218A	Control building	6,673.4
	Substructure	
	Superstructure	
	Building services	
218B	Diesel generator building (2)	7,114.6
	Substructure	
	Superstructure	
	Building services	
218C	Administration building	1,140.7
	Substructure	
	Superstructure	
	Building services	
218D	Turbine service building (2)	2,283.8
	Substructure	
	Superstructure	
	Building services	
218E	Helium storage building (2)	319.8
226	Other reactor plant equipment	22,707.8
	Coolant receiving, storage, & makeup systems	
	Nitrogen cooling system	
	Auxiliary cooling system	
	Decontamination system	
	Miscellaneous suspense items	
227	Instrumentation & control	
	Reactor & process instrumentation, & control equipment	20,034.8
	Automatic monitoring & computing equipment	
	Monitoring systems	
	Isolated indicating & recording gauges, meters, & instruments	
	Control & instrumentation piping & tubing	

TABLE 5-3 (Continued)

	Description	Cost (\$1000)
231	Turbine generators	30,631.0
	Turbine-generators & accessories	
	Generator cooling equipment	
232	Circulating water system	8,844.0
	Water intake facilities	
	Pumps & drives	
	Intake & discharge lines	
	Warming line	
	Discharge tunnel	
	Discharge canal	
233	Condensing systems	11,906.5
	Condensers	
	Condensate system	
	Gas removal system	
	Turbine bypass system	
234	Feedwater system	16,234.7
	Feedwater heaters	
	Feedwater pumps	
	Piping	
235	Other turbine plant equipment	30,479.8
	Main vapor piping	
	Turbine auxiliaries	
	Auxiliary cooling system	
	Make-up treatment system	
	Chemical treatment system	
	Lubricating oil system	
	Miscellaneous suspense items	

TABLE 5-3 (Continued)

	Description	Cost (\$1000)
236	Instrumentation & control Process instrumentation & control equipment Automatic monitoring & control equipment Process monitoring systems equipment Isolated indicating & recording gauges, meters, & instruments Piping & tubing	5,266.8
222B	Secondary helium heat transfer loop Circulators Circulator turbine admission & bypass valves Circulator service system Helium purification system Process heaters (2) Steam generators (4) Reheaters (4) Piping, valves, insulation, installation	31,437.5
222C	Refinery heat transport loop HTS pumps HTS inventory Steam generator Piping, insulation, valves, supports, anchors, & installation	10,181.2
241	Switchgear Generator equipment Station service	4,096.6
242	Station service equipment Startup transformers Low voltage unit substations & lighting transformers Auxiliary power sources	8,263.6

TABLE 5-3 (Continued)

Description		Cost (\$1000)
243	Switchboards	1,827.2
	Main control board for electric systems	
	Auxiliary power and signal boards	
244	Protective equipment	762.0
	General station grounding system	
	Fire protection systems	
245	Electrical structures & wiring	9,100.0
	Containers	
	Underground duct runs	
	Cable trays	
	Conduit	
	Other structures	
246	Power & control wiring	24,792.6
	Generator circuits wiring	
	Station service power wiring	
	Control wiring	
	Instrumentation wiring	
	Containment penetrations	
251	Transportation & lifting equipment	2,367.2
252	Air, hydraulic, water & steam systems	9,172.5
	Sewer systems	
	Air systems	
	Water systems	
	Auxiliary heating steam system	
	Hydraulic power system	
253	Communications equipment	362.6
	Local communications systems	
	Signal systems	

TABLE 5-3 (Continued)

Description		Cost (\$1000)
254	Furnishings & fixtures	629.2
	Safety equipment	
	Shop, laboratory, & test equipment	
	Office equipment & furnishings	
	Change room equipment	
	Dining facilities	
910	Engineering, construction management & field supervision	78,538.4
911	Temporary facilities	10,350.0
912	Construction equipment	18,600.0
913	Construction services	10,710.0
	Other undistributed costs	6,720.0
	Spare parts	
	Owner general office & administrative cost	
	Total BOP cost	472,239.2

TABLE 5-4
BOP COSTS - DUAL REACTOR WITH
STEAM GENERATED AT THE REACTOR CONFIGURATION

	Description	Cost (\$1000)
20	Land & land rights	1,500.0
211	Yard work	3,941.1
	General cut & fill	
	Roads, walks & parking areas	
	Fencing & gates	
	Sanitary sewage facilities	
	Yard drainage	
	Yard lighting	
	Railroads	
212	Reactor containment building & annulus electrical tower (2)	40,853.6
	Substructure	
	Superstructure	
	Building services	
	Containment annulus	
	Annulus electrical tower	
213	Turbine generator building (2)	9,159.4
	Substructure	
	Superstructure	
	Building services	
214	Intake structures	4,438.5
	Circulating water	
	Service water	
215	Reactor service building	20,793.3
	Substructure	
	Superstructure	
	Building services	

TABLE 5-4 (Continued)

Description		Cost (\$1000)
218A	Control building	6,673.4
	Substructure	
	Superstructure	
	Building services	
218B	Diesel generator building (2)	7,114.6
	Substructure	
	Superstructure	
	Building services	
218C	Administration building	1,140.7
	Substructure	
	Superstructure	
	Building services	
218D	Turbine service building (2)	2,283.8
	Substructure	
	Superstructure	
	Building services	
218E	Helium storage building	319.3
226	Other reactor plant equipment	22,707.8
	Coolant receiving, sparge & makeup systems	
	Nitrogen cooling system	
	Auxiliary cooling system	
	Decontamination system	
	Miscellaneous suspense items	
227	Instrumentation & control	
	Reactor & process instrumentation & control equipment	22,038.3
	Automatic monitoring & computing equipment	
	Monitoring systems	
	Isolated indicating & recording gauges, meters, & instruments	
	Control & instrumentation piping & tubing	

TABLE 5-4 (Continued)

	Description	Cost (\$1000)
231	Turbine generators	31,554.3
	Turbine-generators & accessories	
	Foundation & supports	
	Generator cooling equipment	
232	Circulating water system	8,844.0
	Water intake facilities	
	Pumps & drives	
	Intake & discharge lines	
	Warming line	
	Discharge tunnel	
	Discharge canal	
233	Condensing systems	12,533.3
	Condensers	
	Condensate system	
	Gas removal system	
	Turbine bypass system	
234	Feedwater system	18,756.8
	Feedwater heaters	
	Feedwater pumps	
	Piping	
235	Other turbine plant equipment	31,495.2
	Main vapor piping	
	Turbine auxiliaries	
	Auxiliary cooling system	
	Makeup treatment system	
	Chemical treatment system	
	Lubricating oil system	
	Miscellaneous suspense items	
236	Instrumentation & control	5,266.8
	Process instrumentation & control equipment	
	Automatic monitoring & control equipment	

TABLE 5-4 (Continued)

Description	Cost (\$1000)
Isolated indicating & recording gauges, meters, & instruments Piping & tubing	
222B Secondary helium heat transfer loop Circulators Circulator turbine admission & bypass valves Circulator service system Helium purification system Process heaters (2) Steam generators (4) Reheaters (4) Piping, valves, insulation, installation	28,849.2
222C Refinery heat transport loop HTS pumps HTS inventory Piping, insulation, valves, supports, anchors, & installation	8,460.0
222D Refinery steam loop	3,113.1
241 Switch gear Generator equipment Station service	4,096.6
242 Station service equipment Startup transformers Low voltage unit substations & lighting transformers Auxiliary power sources	8,263.6
243 Switchboards Main control board for electric systems Auxiliary power & signal boards	1,827.2

TABLE 5-4 (Continued)

	Description	Cost (\$1000)
244	Protective equipment	762.0
	General station ground system	
	Fire protection systems	
245	Electrical structures & wiring	9,100.0
	Containers	
	Underground duct runs	
	Cable trays	
	Conduit	
	Other structures	
246	Power & control wiring	24,804.4
	Generator circuits wiring	
	Station service power wiring	
	Control wiring	
	Instrumentation wiring	
	Containment penetrations	
251	Transportation & lifting equipment	2,375.0
252	Air, hydraulic, water, & steam systems	9,552.4
	Service systems	
	Air systems	
	Water systems	
	Auxiliary heating steam system	
	Hydraulic power system	
253	Communications equipment	362.6
	Local communications systems	
	Signal systems	
254	Furnishings & fixtures	629.2
	Safety equipment	
	Shop, laboratory, & test equipment	
	Office equipment & furnishings	
	Change room equipment	
	Dining facilities	

TABLE 5-4 (Continued)

Description		Cost (\$1000)
910	Engineering, construction management, & field supervision	78,538.4
911	Temporary facilities	10,350.0
912	Construction equipment	18,600.0
913	Construction services	10,710.0
	Other undistributed costs	6,720.0
	Spare parts	
	Owner general office & administrative cost	
	Total BOP cost	478,533.4

TABLE 5-5
OVERALL COST SUMMARY^(a)

Configuration	Single Reactor	Dual Reactors, Steam at Refinery	Dual Reactors, Steam at Reactor
Capital costs (\$)			
NSS	105,072,000	202,335,000	202,335,000
BOP	284,100,500	472,239,200	478,533,400
17% interest during construction	66,159,100	114,677,600	115,747,700
Total	455,331,600	789,251,800	796,616,100
Annual costs (\$/yr)			
Capital at 0.15 fixed charge rate	68,299,700	118,387,800	119,492,400
Capital at 0.25 fixed charge rate	113,832,900	197,310,300	199,154,000
Operation and maintenance	2,757,000	4,583,000	4,583,000
Nuclear fuel at \$0.42/10 ⁶ Btu	22,607,400	45,214,800	45,214,800
Income from sale of electrical power at \$0.015/kWh	-25,854,500	-87,105,100	-91,288,100
Fossil fuel (oil) at \$2/10 ⁶ Btu	29,193,300		
Total at 0.15 fixed charge rate	97,002,900	81,080,500	78,002,100
Total at 0.25 fixed charge rate	142,536,100	160,003,000	157,663,700
Annual cost/10 ⁶ Btu to refinery (\$/10 ⁶ Btu)			
0.15 fixed charge rate	2.45	1.99	1.91
0.25 fixed charge rate	3.60	3.92	3.86

(a) Nuclear plant capacity factor = 0.90; fossil heater operates at 25% capacity 90% of the year and at 100% capacity 10% of the year.

Fig. 5-1. Refinery heat cost vs. electrical power selling price

Fig. 5-2. Refinery heat cost vs. nuclear fuel cost

Fig. 5-3. Refinery heat cost vs. electrical power selling price

Fig. 5-4. Refinery heat cost vs. nuclear fuel cost

cost capitalization factor of 0.15 (fixed charge rate of 15%). Figure 5-1 shows that, when the electrical power is sold for more than 13 mils/kw-hr, the cost per million Btu's delivered to the refinery is lower for the dual reactor configurations. The different slopes for dual and single reactor configurations are due to the fact that the dual reactor configurations generate nearly four times as much electrical power. The high cost of fossil fuel, relative to nuclear fuel, is the primary reason that the dual reactor configurations are lower in cost. For the dual reactor configurations, the system in which steam is generated at the reactor site has a small cost advantage due to a higher electrical output; i.e., 830 vs. 800 MW.

Figure 5-2 presents refinery heat costs as a function of nuclear fuel cost for a fixed electrical power selling price. The 15 mils/kw-hr electrical power price is the value obtained for a standard 2000 MW HTGR steam power plant using the same ground rules to obtain NSS, BOP, and operating and maintenance costs. Figure 5-2 shows that as the nuclear fuel cost increases the single reactor configuration becomes increasingly attractive relative to the dual reactor configurations.

Figures 5-3 and 5-4 are the same as Figs. 5-1 and 5-2 but with a fixed charge rate of 25% instead of 15%. The higher cost capitalization factor has the effect of penalizing the higher capital cost dual reactor configurations and it is seen that the single reactor configuration is, in many cases, the lower cost system.

5.4 ANALYSIS OF PROCESS HEAT SYSTEM COSTS

The costs for the refinery process heat systems were further analyzed to determine the value of energy at various points in the process. The results of this analysis are shown in schematic form in Fig. 5-5 for the single reactor configuration and in Fig. 5-6 for the dual reactor configuration with steam generated at the refinery. This analysis was performed for a cost capitalization factor of 0.15, an electric power selling price of 15 mils/kw-hr, a fuel oil cost of $\$2/10^6$ Btu, and a nuclear fuel cost of $\$0.42/10^6$ Btu.

Fig. 5-5. Dollar flow through process heat plant, single reactor configuration

Fig. 5-6. Dollar flow through process heat plant, dual reactor configuration, steam generated at refinery

The results for the single reactor configuration indicate that the refinery heat from the nuclear plant alone has a value of $\$1.57/10^6$ Btu, of which the nuclear reactor and fuel account for $\$1.30/10^6$ Btu; intermediate heat transport equipment accounts for the balance. The value of heat from the fossil heater is $\$4.55/10^6$ Btu or nearly three times the cost of the nuclear heat. After accounting for heater efficiency, fossil fuel costs contribute $\$3.29/10^6$ Btu. The high cost of fossil heat adds $\$0.67/10^6$ Btu to the refinery heat cost. The cost of producing electric power is not entirely recovered, and applying this loss to the cost of refinery heat adds an additional $\$0.21/10^6$ Btu. Electric power would sell on a break-even basis at about 20 mils/kW-hr.

The results for the dual reactor configuration show that the value of the refinery heat is slightly less than that for the single reactor configuration, owing principally to economies of scale. However, the cost of producing electric power is not fully recovered, and applying this loss to the refinery heat cost adds $\$0.48/10^6$ Btu. Electric power would sell on a break-even basis at about 18 mils/kW-hr.

The results of this analysis should be qualified to some extent because the division of capital costs among various portions of the plant requires some judgment. The capital costs assigned to various portions of the plant are shown in Tables 5-6 and 5-7. The reactor cost includes the entire NSS cost, including the intermediate heat exchanger, and the cost of supporting BOP systems. The capital cost for the intermediate loop includes piping, circulators, and support systems. The refinery heat transfer loop costs include the helium/HTS heat exchanger, and the steam generator and reheater costs are lumped with steam systems. The steam systems also include all steam plant equipment except the turbine generator set and equipment directly associated with the turbine/generator operation. The control and instrumentation costs and the electric plant costs are difficult to break down because a large proportion of these systems is integrally associated with several portions of the plant. The method used to divide these costs apportioned about 90% of the cost for instrumentation and control to the reactor, with the remainder divided among the rest of the plant in

TABLE 5-6
BREAKDOWN OF BOP COSTS, DUAL REACTOR CONFIGURATION, STEAM GENERATED AT REFINERY

Account No. and Description		Total	Reactor	Intermediate Loop	Refinery Loop	Steam Systems	Turbogenerator Plant
20	Land	1,500.0	919.1	77.0	75.0	289.0	139.9
211	Yard work	3,941.1	2,412.4	202.4	198.2	760.5	367.6
212	Reactor containment building	40,858.6	40,858.6				
213	Turbine generator building	9,159.4					9,159.4
214	Intake structure	4,438.5	310.0			4,128.5	
215	Reactor service building	20,793.3	20,793.3				
218A	Control building	6,673.4	5,298.9	189.0	178.0	689.0	318.5
218B	Diesel generator building	7,114.6	7,114.6				
218C	Administration building	1,140.7	697.3	58.6	57.8	220.5	106.5
218D	Turbine service building	2,283.8					2,283.8
218E	Helium storage building	319.8	159.9	159.9			
226	Other reactor equipment	22,707.8	22,707.8				
227	Instrumentation and control	20,034.8	20,034.8				
231	Turbine generators	30,631.0					30,631.0
232	Circulating water systems	8,844.0				8,844.0	
233	Condensing systems	11,906.5				11,906.5	
234	Feedwater systems	16,234.7				16,234.7	
235	Other turbine plant equipment	30,479.8				27,498.9	2,980.9
236	Instrumentation and control	5,266.8		697.0	682.0	2,621.0	1,266.8
222B	Secondary helium loop	31,437.5		18,485.0	7,920.0	5,032.5	
222C	Refinery loop	10,181.2			10,181.2		
240 to 249	Electric plant	48,842.0	33,138.6	1,932.0	1,891.5	7,265.9	4,614.0
251	Transportation and lifting	2,367.2	2,217.2				150.0
252	Miscellaneous systems	9,172.5	8,051.5	148.0	145.0	558.0	270.0
253	Communications system	362.6	172.5	23.0	22.3	90.1	54.7
254	Furnishings and fixtures	629.2	299.2	39.9	38.8	156.3	95.0
910 to 913	Architect/engineer charges	<u>124,918.4</u>	<u>59,411.2</u>	<u>7,916.8</u>	<u>7,693.1</u>	<u>31,037.3</u>	<u>18,860.0</u>
Total		472,239.2	224,596.9	29,928.6	29,082.9	117,332.7	71,298.1

TABLE 5-7
BREAKDOWN OF BOP COSTS, SINGLE REACTOR CONFIGURATION

Account No. and Description		Total	Reactor	Intermediate Loop	Refinery Loop	Steam Systems	Turbogenerator Plant
20	Land	1,000.0	682.0	51.0	71.0	131.3	64.7
211	Yard work	2,627.4	1,792.0	134.0	186.5	345.0	169.9
212	Reactor containment	20,429.3	20,429.3				
213	Turbine generator building	3,022.5					3,022.5
214	Intake structure	1,633.7	212.0			1,421.7	
215	Reactor service building	12,476.0	12,476.0				
218A	Control building	4,448.9	3,931.3	82.6	115.7	239.5	79.8
218B	Diesel generator building	3,557.3	3,577.3				
218C	Administration building	760.5	518.7	38.8	54.0	99.8	49.2
218D	Turbine service building	1,141.9					1,141.9
218E	Helium storage building	159.9	80.0	79.9			
226	Other reactor equipment	11,353.9	11,353.9				
227	Instrumentation and control	10,017.4	10,017.4				
231	Turbine generator	8,186.9					8,186.9
232	Circulating water systems	2,948.0				2,948.0	
233	Condensing systems	3,836.1				3,836.1	
234	Feedwater systems	5,562.7				5,562.7	
235	Other turbine plant equipment	10,430.7				9,507.8	922.9
236	Instrumentation and control	1,316.7		210.6	292.2	592.0	221.9
222B	Secondary helium loop						
	Process heater	2,244.0			2,244.0		
	Steam generator	2,029.5				2,029.5	
	Reheater	412.5				412.5	
	Circulator, valves, piping, miscellaneous	8,642.5		8,642.5			
222C	Refinery loop	9,666.2			9,666.2		
240 to 249	Electric plant	22,252.1	15,159.1	1,135.0	1,580.0	3,184.4	1,193.6
251	Transportation and lifting equipment	1,155.7	1,051.7				104.0
252	Miscellaneous systems	4,201.6	4,078.6	21.0	29.0	73.0	
253	Communication systems	181.3	99.5	12.1	16.6	35.4	17.7
254	Furnishings and fixtures	386.1	211.9	25.8	35.4	75.4	37.6
910 to 913	Architect/engineer charges	64,019.2	35,130.9	4,279.4	5,861.4	12,506.8	6,240.7
	Subtotal	220,100.5	120,781.6	14,712.7	20,152.0	43,000.9	21,453.3
	Fossil-fired heater	64,000.0					
	Total	284,100.5					

proportion to the cost of major equipment. About 75% of the electric plant costs were included in the reactor cost and the remainder also apportioned according to major equipment costs. Although other distributions of the capital costs could be equally valid, it is unlikely that these would affect the overall conclusions drawn from the results.

It is clear from the results that providing a backup heat source to meet 100% availability requirements for a refinery significantly increases the refinery heat cost. Considerable attention should be given to alternate configurations which could reduce the costs associated with backup systems or increase the revenue from the sale of electric power. The use of heat storage for either emergency refinery heat supply or supplying electric power for peaking are two attractive possibilities. It appears that pursuing alternate schemes in this area would be one of the most promising approaches to reducing the refinery heat cost while maintaining the high reliability required for refinery process heat systems.

6. SAFETY EVALUATION

This section outlines some of the principal safety related issues involved in reactor heat transport for refinery applications. Little distinction is made between the alternative designs; the dual reactor system with steam generated at the reactor site, dual reactor system with steam generated at the refinery, and the single reactor design with a fossil-fired backup heat source. The individual reactor systems and safety systems are similar enough to be treated as a general case.

The only exception is dual reactor operation, with both reactors supplying half of the refinery process heat. As shown in Table 6-1, dual reactor operation results in a slightly higher tritium level in the HTS system; however, this is still well within acceptable limits. There have been no operational safety problems identified with the dual reactor case since the reactor heat sources will be run as independent units.

Analysis indicates that contamination of the heat transfer fluid, HTS, and steam by radioactivity, primarily tritium, will be well within acceptable limits and therefore presents a minimal hazard to refinery operation. Heat exchanger equipment and transport system failures do not lead to accident conditions because of the relatively low radioactive inventories associated with each of the transport systems and chemical compatibility of the heat transport and process fluids.

6.1 RADIOACTIVE CONTAINMENT

6.1.1 Fission Products in HTGRs

Effective fission product control is easily maintained in the 2000 MW(t) process heat reactors with intermediate helium loop systems. This results in refinery product contamination well within acceptable limits.

TABLE 6-1
TRITIUM PERMEATION THROUGH HEAT EXCHANGERS

	Tritium Permeation Rate (curies/year)	Temperature Range (°F)	Tube Thickness (in.)	HX Material	HX Area (ft ²)
Primary/intermediate loop	1970	1350 - 642	0.025	Incoloy 800	4.98 x 10 ⁵
Single reactor intermediate loop/HTS system	14	1200 - 980	0.10	Incoloy 800	1.02 x 10 ⁵
		980 - 758	0.2	SS316	
Dual reactor intermediate loop/HTS system	65.7	1200 - 980	0.10	Incoloy 800	2.04 x 10 ⁵
		980 - 758	0.2	SS316	
Single reactor intermediate loop/steam system	133	845 - 673	0.10	Incoloy 800	1.48 x 10 ⁵
		800 - 440	0.0625	2-1/4 Cr-1 Mo	
Dual reactor intermediate loop/steam system	112	1150 - 586	0.10	Incoloy 800	1.24 x 10 ⁵
		780 - 449	0.0625	2-1/4 Cr-1 Mo	

The barriers and sinks provided by the process heat HTGR prevent fission products from being transported out of the reactor primary system and intermediate loop system, with limited fission product releases during postulated intermediate loop or HTS system failures.

The first and most important fission product barrier in the HTGR is the fuel particle coating. The effectiveness of this boundary depends principally on the material properties of the coating layers, service temperature, fission product half-life, and product atomic number. Under normal operating conditions, the SiC coatings of the TRISO fissile particles provide an absolute barrier for metallic fission products. The pyrocarbon coatings provide more of a selective barrier with some product retention and permeation by gaseous products and iodine.

The next retention barrier is the fuel rod matrix and structural graphite. Both the matrix and the graphite contain large surface areas in which less volatile fission products can be absorbed, but the effectiveness of the matrix as a diffusion barrier or capacity for holdup is minimized by the homogeneous distribution of fuel within it and its higher operating temperature. However, the structural graphite does provide an effective diffusion delay for metallic fission products, again depending on half-life, atomic number, and temperature. The structural graphite has little effect on gas transport because of its high permeability, allowing predominately gaseous products out into the primary coolant circuit.

Within the primary circuit, the purification systems and surfaces of the primary coolant boundary serve as a trap for fission products, and maintain the equilibrium helium activity at a relatively low concentration. Long life fission products along with other impurities are removed in the purification system by first passing through a high-temperature absorber, where metallic fission products and iodine are removed. Next, the gas stream is cooled and passed through a low-temperature absorber, where noble gases such as krypton and xenon are taken out. Finally, hydrogen and tritium are removed from the flow by passing through a getter unit consisting of a titanium sponge before returning to the main coolant system.

With these retentive fission product barriers and two independent closed heat transfer loops separating the primary system and refinery process system, tritium remains as the only radioactive contaminant of potential concern during normal operation. Although tritium transport through metal barriers is by diffusion, separate heat exchanger barriers that the tritium source term must travel through diminish the activity at the process end to a level low enough that it is of little or no concern from the standpoint of public health and safety.

6.1.2 Mechanism for Tritium Production and Transport

Tritium production in HTGRs results from ternary fission and from neutron activation reactions. The major reactions are with He-3 in the helium coolant,* Li-6 trace impurities in the core and reflector graphite, and B-10 in the control rods. All other tritium producing reactions are insignificant due to negligible concentrations of the reactive product or low reaction thresholds (Ref. 21).

The equilibrium H-3 in the primary helium coolant is maintained at a low value by partial retention in the core graphite and control rod structural material and by H-3 removal by titanium absorbers inside the purification system. Additional removal is by diffusion through various metals that act as the boundary of the primary system. Although the mechanism of H-3 diffusion is not entirely understood, experimental data on hydrogen permeation through metals is available and can be used to arrive at an estimate of H-3 permeation results (Ref. 22).

Chemically, tritium is nearly indistinguishable from hydrogen and has been shown to exhibit similar permeation characteristics in controlled environments (Refs. 22-24). The only difference between H-3 and H-2 permeation rates is that H-3 has $1/\sqrt{3}$ times the H-2 rate under identical conditions. This correction factor is applied to allow for the mass dependence of the diffusion jump frequency (Ref. 25).

*The He-3/He-4 atom ratio in the helium coolant is 2×10^{-7} .

Other influences on permeation rates include metal temperature and material composition. Permeability increases exponentially with increasing metal temperature because vibrational excitation of the constituent atoms with increasing temperature expands the lattice structure and allows gas atoms to migrate more rapidly from one interstitial site to another. Material composition also has a strong effect on hydrogen and tritium permeation. Pure metals show a wide range of diffusion rates (Ref. 21) indicating that experimental verification is necessary to accurately predict tritium permeation through various heat exchanger materials.

Surface oxidation inhibits the gaseous diffusion through metals by providing a protective film on the metal, altering the metallic constituents incorporated in the film. However, for the purposes of this study, no credit is taken for the buildup of an oxide coating on any heat exchanger surface. Data for various oxidized surfaces is difficult to obtain, and since the actual surface conditions of the heat exchanger materials during service are unknown, this conservative approach has been taken.

Surveys have been conducted at Peach Bottom to quantitatively monitor the rate of the tritium diffusion through the steam generator walls. Based on the results of these surveys, design and expected levels of tritium diffusion have been extrapolated for large HTGRs. These estimates have taken into account the difference in plant parameters that influence the rate of tritium diffusion and give results that are somewhat comparable to analytical approaches. This information has been used to calculate the source term H-3 released to the primary system coolant for a 2000 MW(t) HTGR used for this refining application.

6.1.3 Tritium Permeation into Transport and Steam Systems

Calculations of tritium permeation rates through the heat exchangers and steam generators of a 2000 MW(t) HTGR heat source indicate that extremely low radioactivity, well within the guidelines of Appendix I to 10CFR50, would be introduced into the petroleum process stream. Actual transport through the process heat exchangers from the heat transport salt

system has not been specifically examined since design of the petroleum process heat exchanger equipment was not within the scope of this study. However, the low levels of activity entering the HTS from the intermediate helium loop show that this presents essentially no operational or safety problems.

Table 6-2 summarizes the maximum or design condition tritium permeation and equilibrium inventories expected in the HTGR heat transport and steam generation systems. These calculations are based on the assumptions that the permeation behavior of tritium at very low concentrations in helium can be extrapolated from the permeation mechanism of hydrogen, and that the permeation rate is inversely proportional to the thickness of the heat exchanger tubing. In addition, no credit is taken for back permeation of tritium in the presence of concentration gradients across the heat exchanger tube boundary or any lowering of tritium permeation rates by films or oxides formed between the impurities in the heat transport coolant and the metal surfaces.

On the basis of equilibrium considerations, and assuming no decay of tritium, the tritium generation rate N_t in the primary coolant should be equal to the rate of loss of tritium N_t' from the helium coolant by permeation through the intermediate heat exchangers plus the rate of tritium removal N_t'' in the purification system:

$$N_t = N_t' + N_t''$$

This also applies to the intermediate loop and process heat transport system. Additional helium purification in the intermediate loops contributes to some tritium removal, while removal in the HTS system and closed steam cycle systems is by normal coolant leakage and makeup.

Evaluation of the equilibrium inventories in each of the closed systems is by using the heat exchanger permeation rates of tritium as the new source term, N_t .

TABLE 6-2
SYSTEM RADIOACTIVITY AND CLEANUP RATES

	Total Design Circulating Activity (curies)	Tritium Inventory (curies)	He Cleanup Rate (lb/hr)
Primary system	1.27×10^5	1.63	2000
Intermediate He loop system	4.62×10^{-1}	4.62×10^{-1}	1800
Single reactor HTS system	4.7×10^{-3}	4.7×10^{-3}	
Dual reactor HTS system	7.0×10^{-3}	7.0×10^{-3}	
Single reactor steam system	4.6×10^{-2}	4.6×10^{-2}	
Dual reactor steam systems	6.9×10^{-2}	6.9×10^{-2}	

The tritium permeation rate N'_h is given by:

$$\frac{N'_t}{N'_h} = \frac{C_t}{C_h} \frac{1}{\sqrt{3}},$$

where C_t and C_h are, respectively, the concentrations of the tritium atom and the hydrogen atom at the metal surface.

Permeation from the primary system to the intermediate loops is more than an order of magnitude greater than the permeation through the heat transport salt exchanger, the steam generators, and reheaters. The principal factors limiting the diffusion through the secondary system are:

1. Tube thickness. The metal boundary formed by the heat exchanger tubing is much greater on the secondary systems compared to the intermediate heat exchanger. See Table 6-1.
2. Larger surface area. The total heat transfer and available permeation area is more than twice as large with the intermediate loop compared to the secondary system.
3. Purification. Helium cleanup systems in the intermediate loops contribute to tritium removal, reducing the equilibrium inventory and heat exchanger permeation rates.
4. Material differences. The predominant material used for the intermediate loop is 2-1/4 Cr-1 Mo, a metal that has been shown to have greater hydrogen permeation than the nickel alloys such as Incoloy 800.

6.2 HTS/PETROLEUM PROCESS INTERACTION

6.2.1 Chemical Reactions

There are several processes involved in the utilization of the HTS heat carried from the reactor heat source to the petroleum refinery system. A summary of these is given in Appendix A. As indicated, the majority of the processes are at high operating pressures (above 300 psig). This compares with the HTS pressure at the refinery of 200 psig. Therefore, heat exchanger tube failures will cause hydrocarbon leakage into the HTS system; precautions could be taken such as duplex tubes and/or double tube sheets where conditions warrant it.

Although the HTS itself is nonflammable and will be circulated in a completely closed system, combustible vapors would be generated by the introduction of hydrocarbons from the petroleum process into the elevated temperature inorganic fluid. Chemical reaction with the HTS is relatively slow, and the precautions would be necessary to assure that the vapors do not become exposed to an air- or oxygen-containing atmosphere. Experience with liquid metal systems has shown that noncondensable gases and vapors can be successfully removed from the transport system by allowing gas bubbles to surface into a gas space. This can be accomplished in the pressurizer normally used to maintain system design pressure in the HTS system. The inerted cover gas above the pressurizer system can be used to collect and remove any combustible vapors from the HTS system.

Petroleum products and other flammable liquids tend to vaporize rapidly in contact with the molten HTS and burn when mixed with air. For example, crude oil has been shown to burn in a similar manner on the open surface of the HTS at 1150°F and on the surface of molten lead at the same temperature (Ref. 9). Where motor gasoline, cracked gasoline, gas oil, and crude oil mixed with sulfur were released below the surface of an open container of HTS at 1100°F, the hydrocarbons vaporized and burned; in the cases of crude oil and gasoline, hot salt spattered considerably due to the rapid, sub-surface vaporization of the liquids. Chemical analysis showed

little change in the salt composition, indicating that the principal reactions were between the vaporized hydrocarbons and the air above the salt bath.

6.2.2 Petroleum Process Contamination

Portions of the process conducted at lower pressures than the HTS (see Table 6-3) cause HTS contamination into the process fluid when there are heat exchanger tube leaks or failures. Chemically, because of the non-reactive behavior of the HTS, there is little or no safety concern, although impurities introduced into the process stream could affect the commercial acceptability of the final products.

HTS leaks would introduce small amounts of radioactivity into the process stream in the form of tritium present in the inorganic salt. However, since only small amounts of tritium and other activity are expected to leak or diffuse into the HTS system from the helium system, the equilibrium concentrations in the HTS system will be no more than 2.19×10^{-6} μ curies/cc, approximately the background concentration in water. For an assumed equivalent leak rate of 0.1 lbm/day of HTS into the process stream, the activity released through the process itself would be 5.5×10^{-5} μ curies/day.*

Dilution in the 75.5×10^6 lb/day refinery product flow results in a large reduction in activity release concentrations to an estimated 2×10^{-10} μ Ci/cc. This is four orders of magnitude below background tritium concentrations in water, and clearly is acceptable within the guidelines of both 10CFR20, "Standards for Protection Against Radiation," and the new 10CFR50 Appendix I, "Licensing of Production and Utilization Facilities." Further, because of the conservative assumption used in the tritium diffusion calculations the concentration could be even less in actuality.

*0.1 lbm/day of primary helium is the equivalent reheater leak rate assumed for normal release calculations in the Delmarva Preliminary Safety Analysis Report for a 2000 MW(t) HTGR.

TABLE 6-3
REFINERY PROCESS HEAT EXCHANGERS LEAK PATHWAYS

Process Exchanger	Process Fluid	HTS Flow Rate (1 x 10 ⁶ lb/hr)	Operating Pressure (psig)	
			Process	HTS
Leaks Resulting in Contaminated HTS				
Recycle gas	Hydrocarbon vapor	2.94	2300	200
Recycle oil	Hydrocarbon liquid	0.184	2350	200
Debutanizer reboiler	Mixed phase	1.49	300	150
Ultrafiner charge	Vapor	3.22	800	150
Ultraformer charge	Vapor	2.60	400	200
Preheater	Vapor	6.93	325	200
Stripper reboiler	Mixed phase	2.03	275	150
Debutanizer reboiler	Mixed phase	1.47	250	150
Leaks Resulting in Contaminated Process				
Sputter reboiler	Mixed phase	1.43	30	150
Prefractionator reboiler	Mixed phase	1.82	20	150
Atmospheric heater	Mixed phase	7.8	45	180
Vacuum heater	Mixed phase	7.8	-11	150

The principal unrestricted pathway for this extremely low level of radioactive release that would give rise to radiation exposure would be through use of the petroleum products. Home heating usage probably represents the most direct form of exposure to tritiated petroleum products. In this case, even assuming conservative dilution factors, the activity would be no more than 10^{-12} μ curies/cc. This level of tritium activity is eight orders of magnitude lower than the initial activity levels anticipated in the principal exposure pathway of natural gas released by nuclear stimulation under the Plowshare Program (Ref. 20). The tritium levels found in these wells were 7×10^{-4} μ Ci/cc for the Rulison test (Ref. 26).

The present Nuclear Regulatory Commission (NRC) guidelines that give applicable standards for acceptable radioactivity releases are 10CFR20, "Standards for Protection Against Radiation" and the new 10CFR50 Appendix I, "Licensing of Production and Utilization Facilities." Although these are written specifically for discharged effluents of light-water power reactors, they have been applied to HTGRs and probably will be applied to process gas-cooled reactors. The newly adopted guides limit the annual dose or dose commitment from liquid effluents from the reactor for any individual in an unrestricted area from all pathways of exposure to not more than 3 millirems to the total body and 10 millirems to any organ, (Ref. 27).

Based on equivalent doses calculated by Barton et al. (Ref. 28), the 10^{-12} μ Ci/cc activity would amount to only 2×10^{-6} millirem/year. This is clearly acceptable under present guidelines and any revisions that may occur. This also implies that even if large errors are present in the tritium diffusion calculations, tritium contamination of the process product would still be insignificant.

6.3 PRIMARY/INTERMEDIATE LOOP HEAT EXCHANGER FAILURE

Although the primary and intermediate loop helium pressures are approximately the same, small pressure differences will cause helium leaks from tube failures to flow in one direction or the other. This section

identifies the principal safety advantages and disadvantages of alternative design pressure levels in each system.

The first possibility is maintenance of the intermediate system at a higher helium pressure than the primary system. The main advantage of this is that radioactivity in the primary system, other than the tritium that diffuses through the heat exchanger walls, can be contained within the primary coolant boundary during postulated leaks. This is similar to the steam cycle HTGR safety philosophy, except in this case steam introduction and graphite reaction are not of concern.

The disadvantages of this concept are that leak detection would be difficult since there are negligible differences between the primary coolant helium and intermediate coolant except for activity levels. Small leak detection may be possible by introducing a trace element into the intermediate system with detectors in the primary system. An inert gas such as argon may prove suitable for this purpose; however, further investigation is necessary to assure compatibility with the primary system chemistry and for economic justification. Leak detection would require a total plant shutdown and repair in order to prevent overpressurization of the PCRV, which would affect total availability of the reactor facility for process heat duty.

A second alternative is maintenance of the intermediate loop system at a lower pressure than the primary system. Tube leak detection would easily be provided by sensitive radiation monitors located downstream in each of the three intermediate heat exchanger loops. Isolation by the containment isolation valves in each loop would assure that the release to the secondary system is limited and localized to a small section of the entire intermediate loop system. Plant availability with reduced capacity could be maintained by continued operation with the one leaking loop shutdown until a routine reactor shutdown and maintenance period is reached.

In order to assess these alternatives, a more detailed design of the heat exchanger systems is needed. An attempt has been made here only to outline the safety implications of the alternatives. Specific information

such as value response times, heat exchanger design, and systems costs will have a significant impact.

6.4 INTERMEDIATE LOOP FAILURES

The intermediate helium heat transfer system described in Section 4.2 couples the primary helium system with the HTS and steam generator systems. Piping entering and leaving three primary-to-secondary helium heat exchangers penetrate the PCRV and containment building and are connected in parallel to a common ducting before transferring heat to the process fluid.

Isolation of the piping lines penetrating the containment, as required by 10CFR50 Appendix A,^{*} is provided by valves located on the outside containment boundary on all six pipe systems. Failure of this piping system should present no significant safety problem since the system has a relatively low radioactive inventory.

Plant protection system (PPS) monitoring of the core inlet temperature will indicate a depressurization event of the intermediate loop and a reactor trip will be initiated. The loss of coolant circulation and reduced pressure would reduce the helium coolant capability to effectively remove reactor generated heat. This new requirement should not affect plant operation since this type of intermediate loop failure should be a low probability event.

6.4.1 Intermediate Loop Pipe Rupture Outside of Containment

A postulated offset shear rupture of one of the 7 ft diameter low-temperature helium inlet lines or 8 ft diameter high-temperature outlet lines outside of the containment would cause a release of radioactivity to the environment. However, since the only source of radioactivity contributing to the equilibrium inventory of this system is tritium diffusing through the primary-to-secondary helium heat exchangers, a total release

^{*} Criterion 57 - Closed System Isolation Valves.

of the helium inventory, with no credit for isolation, results in a release of 0.462 curie of tritium. This would give inhalation whole body doses that are 10^{-3} of those that are calculated for secondary coolant releases of steam cycle HTGRs at typical reactor site exclusion area boundaries (EAB) (Ref. 29). This, therefore, should be acceptable from a licensing viewpoint.

6.4.2 Intermediate Loop Pipe Rupture Inside of Containment

A postulated failure of one of the intermediate loop piping systems inside of the containment boundary would result in a release of helium to a closed vessel. Although isolation by closure of the safety class containment isolation valves would prevent complete loss of the 8000 lb of helium inventory, the containment can withstand the depressurization of the intermediate loop system. Since the containment is designed for the Design Basis Depressurization Accident (DBDA) of the primary coolant system, which has an 88% greater inventory, intermediate loop failure will not impose excessive demands on this fission product barrier. Therefore, this principal issue, over-pressurization of the containment boundary, should not be of concern if a containment structure similar to that of large steam cycle HTGRs is adopted.

7. RESEARCH AND DEVELOPMENT REQUIREMENTS

The HTGR research and development requirements necessary for this process heat application are limited mainly to component development work. Little or no reactor core modifications are anticipated since the operating conditions are similar to that of large steam cycle HTGRs currently being designed. Likewise, it is assumed that the fuel cycle will be identical with that adopted by the steam cycle HTGR, so that the fuel economics will be comparable.

The helium system components that are the principal development items are the heat exchangers, circulators, and valves. As indicated, much of the development effort will rely on present development programs, and represent an extension to achieve the components and systems designs necessary for commercial refinery applications.

7.1 HEAT EXCHANGER DEVELOPMENT

Heat exchanger equipment, which transfers heat from the primary to the intermediate helium systems and from the intermediate helium systems to the HTS system, will require some development effort and test verification. The steam generator designs will be similar to existing large steam cycle HTGR steam generators, but will be smaller in size and, therefore, will make use of existing technology.

7.1.1 Helium/Helium Heat Exchanger

The development effort necessary to arrive at a suitable intermediate helium heat exchanger design is similar to that required for the gas turbine HTGR recuperator, which also transfers heat from one helium system to another (Ref. 30). Figure 7-1 shows the helium/helium heat exchanger design for a

Fig. 7-1. Intermediate helium/helium heat exchanger

2000 MW(t) reactor plant transferring heat through three separate loops. A detailed description of this heat transfer system is provided in Section 4. Development tasks necessary to confirm that this design meets all performance requirements are summarized below.

7.1.1.1 Vibration Testing. Vibration testing on representative sections of the heat exchangers will be necessary to assure that material fatigue will not be introduced by the bending stresses accompanying the tube movement. Service conditions will be modeled so that the full effect of coolant temperature, pressure, and flow rate will be understood. Since the reactor system will not be subjected to rapid changes in load conditions, transient effects will be of secondary importance. Work contributing to the building of the test rig(s) will include the development of specifications, the design and construction of the test equipment for vibration measurement, instrumentation, and planning of the test program.

Two kinds of vibration tests will be performed:

1. Small-scale samples of the bundle tubesheet joints and support structures will be subjected to mechanical vibration.
2. Representative module sections will be tested to examine flow-induced vibration effects.

The latter tests, which represent most of the testing effort, will be carried out under conditions that simulate the actual tube bundle flow forces and dynamic forces as closely as possible. The flow-induced vibration testing will be carried out with air as the test medium; flow, temperature, and pressure levels will be selected to give close-to-design values of Reynolds number and aerodynamic loading. Following the experimental program, results will be evaluated, and modifications, if required, will be made to the joint and tube support designs.

7.1.1.2 Friction and Wear Tests. A companion program to the flow-induced vibration testing will be friction and wear testing for the tube support and other components in the heat exchanger that will be subjected to sliding action in the actual unit. These tests will use materials intended for service and will simulate the actual geometry where rubbing may occur. Tests will be conducted in helium at the temperatures and impurity levels expected in the reactor system. Samples will be examined metallographically after completion of testing.

The material oxide coating will be examined so that tritium diffusion parameters can be established. As indicated in Section 6, this information is necessary in order to accurately define equilibrium radioactivity levels in the intermediate helium loop.

7.1.1.3 Structural Analysis. As the primary system boundary, the intermediate heat exchanger will be designed as a Safety Class 1 component and therefore will follow the rules of ASME Boiler and Pressure Vessel Code, Section III, Nuclear Components. All major pressure boundary and load-carrying parts of the exchangers will receive a detailed structural analysis, including pressure, seismic, dead weight, fluid drag, and thermal loading. Analysis will develop stress magnitudes, categorize the stresses, and apply specific allowable limits to each category of stress. Generally, the categories will be mechanical primary stresses, thermal secondary stresses, and peak stresses. Boundaries will include fatigue considerations and time-dependent creep effects will be included for high temperature regions.

7.1.1.4 Thermal and Pressure Cycle Tests. A test module of representative surface geometry will be constructed for thermal and pressure cycle tests. It is likely that the flow-vibration test rig could be modified to handle this phase of the test program. Data from this test will be compared with the estimated values of temperature gradients and stress levels to verify the mathematical models and analytical tools used in the structural and thermal analysis.

7.1.1.5 Tube Plugging. Evaluation of tube plugging will be made. Influence on heat transfer performance will be analyzed and compared to experimental work. Maintenance factors for tube or module plugging will be incorporated into the design so that procedures and maintenance equipment can be developed at a later time.

7.1.2 Helium/HTS Heat Exchanger

Design verification of the parallel counterflow helium/HTS heat exchanger equipment will follow a program similar to that of the intermediate heat exchanger development effort. These tests will require separate facilities than those used for the intermediate loop heat exchanger testing. Modeling of fluid transport characteristics of the HTS may be conducted using water as a substitute for the HTS, reducing the costs of the tests. Likewise, extensive data from existing molten salt development programs should be of value in evaluating the corrosive behavior and heat transfer properties of the HTS. Since the heat exchanger equipment does not form the primary coolant pressure boundary, and has only minor nuclear safety considerations, it probably can be designed to a low safety classification or be non-nuclear rather than designed to the ASME Code, Section III.

7.2 CIRCULATOR DEVELOPMENT

Helium circulators needed in both the primary and system and intermediate loop system are larger and operate under different conditions than these used on the current 3000 MW(t) HTGR designs. As outlined in Section 4.4, the power requirement for the steam cycle plant circulator is 14,000 hp. This compares with three 27,500 hp primary circulators and three 25,000 hp intermediate loop helium circulators. Although the basic design is an extension of steam cycle HTGR technology, using the same water bearings principle, steam drive, single-stage helium circulator blading, and rotating shaft speed, the helium blading aerodynamic characteristics and steam drive conditions are different enough to require testing. This testing

program would verify the design and off-design performance of the circulators, including stall characteristics under simulated operational conditions.

7.2.1 Performance Tests

For these large circulators, at least a one-third scale model test of the compressors and associated flow path are necessary. A common test rig for both circulator designs is probably suitable, as long as appropriate steam conditions for both designs are simulated. Like the test rig now being built to test 14,000 hp HTGR circulators, testing would be done using atmospheric air (Ref. 31). This choice of fluid, coupled with the reduced size, enable flow similarity to be preserved, in particular parameters such as Mach number and Reynold's number, while permitting extensive testing at reduced speed and power. The following information would be pertinent for this type of test verification:

1. Overall compressor performance.
2. Inlet flow characteristics for different flow contours.
3. Diffuser flow characteristics.
4. Effect of reactor component misalignment on compressor inlet flow.
5. Effect of shutoff valve position on discharge flow.
6. Back flow torque resulting from reverse flow through the compressor blading.
7. Noise levels generated by the compressors.

7.2.2 Thrust Loads

Thrust bearing performance testing for these large circulators may be necessary. Figure 7-2 shows a rotor inertia simulator used for Fort St. Vrain 5200 hp circulator bearing and rotor dynamics testing. This test rig can probably be modified to subject the process heat circulators to simulated anticipated loads. This can be accomplished by pressurizing a dome region over the compressor end in order to subject the rotor to thrust loads.

Thrust bearing performance can be determined by this rig for a range of speeds, thrusts, clearances, and supply pressures by measuring bearing pressure profiles in both the tangential and radial directions. Unbalance conditions can be simulated to give rotor response at operating conditions, with displacement measurements and unbalancing force measurements being made to verify analysis.

These tests should provide adequate verification of the design to proceed to actual prototype testing and plant testing. Additional acceptance testing of all production circulators prior to delivery to the reactor site will be part of the overall qualification program. These acceptance tests will include numerous starts and stops and transient cycles, and endurance steady-state operation at 100% speed and temperature.

7.3 VALVE DESIGN DEVELOPMENT

The valves used in the reactor and transport systems depend, to a certain extent, on the particular system design alternatives. Valve development efforts will be required on valves used in the intermediate helium transport system, while it is expected that none will be necessary for the valves used in the HTS system. The HTS valves used in the three alternative designs are relatively small diameter valves, and must function as isolation valves only.

Fig. 7-2. Rotor inertia simulator

7.3.1 Helium Valves in Single Reactor with Fossil Fuel Back-Up

The type of valving requirements for this helium system are the simplest of the alternatives. A summary of these is the following:

1. Primary loop shutoff valve. This would be similar to the present steam cycle HTGR valves, both in design and function.
2. Intermediate loop shutoff valve. This could also be similar to the present HTGR valves, located near the circulator diffuser.
3. Containment isolation valves. These valves are necessary to isolate the sections of the intermediate loop that penetrate the containment building boundary.

7.3.2 Helium Valves for Dual Reactor Concepts

Both designs (steam generated at the reactor and steam generated at the refinery) need the same types of helium valves. These are:

1. Primary loop shutoff valve.
2. Intermediate loop shutoff valve.
3. Containment isolation valve.
4. Flow control valve.

The first three are identical to those needed in the single reactor case. The flow control valve is needed to regulate the flow in the intermediate loop systems. As shown in Fig. 2-3, a portion of the helium flow must be diverted to the HTS heat exchanger, while the remainder goes to the steam generator. When one of the two reactor systems is shut down, the flow in the operating 2000 MW(t) reactor must all be directed to the HTS system, with the steam generator system shut down.

7.3.3 Testing Requirements

The development effort for the containment isolation valves and the flow control valves will include a testing program. This program would be similar to the development of the present large HTGR primary coolant shut-off valves, which have been tested to demonstrate the performance and suitability as primary coolant shutoff valves. The valve tests were conducted using an air test rig. Data were obtained for leakage, closing time, free position versus flow, pressure drop, and flow stability. All test objectives were realized and no significant technical problems were encountered in this program, including actual production valve testing at the Valmont Test Facility, near Fort St. Vrain in Colorado, in conjunction with production circulator testing.

A similar test rig could be used to test both the containment isolation valves and flow control valves in the intermediate helium system. Isolation valve testing will include verification of mechanical valve operation, leakage, structural integrity, and reliability. The response times, along with leak tightness requirements, will be established by the safety criteria and design basis accident events.

The important characteristics of the flow control valve that should be tested include structural integrity, correlation between flow conditions and valve positions, drag characteristics, and reliability.

7.4 DEVELOPMENT COST ESTIMATE

The total cost of the component development program is \$13,268,400. This has been computed in 1975 dollars and does not account for escalation factors resulting from actual development program schedules. Development program schedules have not been included since this report is limited to establishing a reference process heat reactor design for refinery applications. The level of component development funding required for research and development indicates the additional cost expenditures required to advance

the HTGR system design for this application beyond the current large steam cycle HTGR design.

Since the reactor power and temperature conditions do not exceed present licensable HTGR designs, no new reactor development work is necessary. Likewise, it has been assumed that the HTS system design is within the limits of known technology and will require little development effort.

The costs presented in Table 7-1 are intended to include the costs of component development, test rig design and construction, testing, design engineering, and other costs which would not be repeated for subsequent reactor plants designed and constructed.

TABLE 7-1
COMPONENT DEVELOPMENT COST ESTIMATE (\$)

1.	Heat Exchanger Design and Testing	
	Design and test labor	4,580,000
	Hardware and construction	432,000
2.	Circulator Design and Testing	
	Primary circulator design	640,000
	Intermediate loop circulator design	745,000
	Test facilities hardware and construction	4,000,000
3.	Valve Design and Testing	
	Isolation valve development	130,000
	Flow control valve development	130,000
	Test rig hardware	400,000
	TOTAL COST	11,057,000
	With 20% contingency costs	13,268,400

8. PLANT AVAILABILITY

Plant availability for a standard steam plant is the percent of total time in a given period that the plant is available for producing electricity. It is equal to the time the generator was available for electricity production divided by the total time during the period. For the nuclear process heat plant, availability will be defined as the percent of the total time in a given period that the plant is available for producing process heat.

The steam-producing HTGR has a total scheduled outage of 16 days per year and thus a scheduled plant availability of 95.6%. All economic calculations were based on a 90% load factor because nuclear-heated process heat plants are expected to be base loaded, and thus outages should be less frequent than with electrical plants.

9. CONCLUSIONS

1. The HTGR does provide a practical means of supplying process heat for petroleum refining and other petrochemical processes.
2. The use of an intermediate helium loop to remove heat from the reactor coolant and transfer it to steam generators and process fluid heaters is practical.
3. HTS is a practical, low cost heat transport fluid for temperatures up to 1100°F.
4. The use of gaseous heat transport fluids results in large piping and pumping cost penalties when the fluid must be transported over distances greater than a few hundred feet.
5. The selection of a means for providing a backup heat source is highly dependent upon nuclear and fossil fuel costs, electrical power costs, and the method used to capitalize the NSS and BOP costs.
6. The proposed method of supplying process heat is exceptionally safe because of the low radioactive inventories handled in the heat transport fluid.

10. RECOMMENDATIONS

1. A more extensive search for desirable heat transport fluids should be undertaken.
2. While the current study was limited to producing and transporting heat at 1100 F, the selection of heat transport fluids and the design of reactor systems for other temperatures may be desirable.
3. The time and budget limitations of this study did not allow a sufficiently detailed examination of control systems, particularly with regard to startup and faulted operation.
4. A more detailed flexibility analysis of the heat transport loop piping should be undertaken.
5. Design details of the heat transport loop anchors and supports should be established.
6. It is believed that a single reactor system which is not required to generate electrical power would result in a significant cost savings and an investigation of this alternative is recommended.
7. Including a fossil-fired heater for immediate standby operation accounts for a large proportion of the overall cost. Alternate methods for emergency power should be considered.
8. The use of a molten salt heat storage system to supply electric power for peaking should be considered.

As an extension of the work discussed above, a twin 2000 MW(t) HTGR was studied as a process heat source. The results are presented in Appendix B.

APPENDIX A
REFERENCE REFINERY HEAT BALANCE

The data in the attached exhibits were provided by Amoco Oil Company.

Exhibit I is a possible refinery layout arranged in such a manner as to minimize piping distances for the high temperature heat transfer medium.

Exhibit II is a summary of low temperature heat and power requirements for the refinery. Low temperature heat is supplied in the form of steam at 575 psig, 700°F and at pressures of 140 psig and lower via noncondensing mechanical drive steam topping turbines. Total load is approximately 1600 MW(t) and is equivalent to 20,500 BCD of fuel or a little over 8% of refinery throughput.

Exhibit III is a concept of a circulation system for the heat transfer medium. Note that several services are placed in series in order to reduce heating medium return temperature. Temperature crosses in several individual heat exchanger services will also require flow of heating medium through a series of two or more exchangers (pressure drop may be a problem).

Exhibit IV is a summary of the heat exchangers shown in Exhibit III. Molten salt is shown on the tube side in order to minimize inventory. This will make difficult the cleaning of exchangers with high fouling factor stocks on the shell side. Some of the process pressures will be low relative to the heating medium pressure, thus leakage of salt into the process will be a problem requiring further investigation.

Shell Oil Company supplied additional data on refinery heat loads and shutdown schedules, and hydrogen requirements.

Refinery layout - prototype of 250,000 BCD refinery

1-24-75

UTILITIES SUMMARY
250,000 BCD Refinery

	Steam Mlb/Hr				Mlb/Hr Condensate Return				Mlb/Hr BFW	Power KW	Water 1000 GPM
	575	140	60	15	480°F	350°F	300°F	115°F			
Ultracracker	532	59	108	71	46	33	-	215	-	6,000	58
Ultraformer	481	52	150	-	-	36	-	243	-	12,800	33
Crude Unit	-	193	-	-	-	87	-	-	-	7,800	6
Coker	241	178	-	-	30	-	-	-	-	1,700	1
FCU	137	117	-	-	-	-	-	-	294	1,100	9
MEA-SRU-SWS	116	166	243	-	-	166	266	-	150	3,500	7
Propylene	47	-	17	-	-	17	1	46	-	600	4
Alkylation E ₄	38	41	5	-	-	41	5	38	-	2,400	5
Dist Desulf	-	2	-	-	-	2	-	-	-	5,100	Neg
FCU Feed	-	47	-	-	-	31	-	-	-	9,400	11
Plant Air	-	-	-	-	-	-	-	-	-	5,000	-
Shipping	-	-	-	-	-	-	-	-	-	4,000	-
Storage	-	25	-	75	-	-	-	-	-	1,000	-
Cooling Towers	68	-68								7,400	-
Sub-totals	1154	0	7	4	76	413	272	542	444	67,800	134
Auxiliaries	11	-	-7	-4	-	-	-	-	1226	4,600	1
Totals	1165	-	-	-			1303		1670 1303	72,400	135
							Makeup Water		367		

Heat Duty - Steam Generation	= 1344 MBtu/Hr (t)
Boiler Blowdown (5%)	16 MBtu/Hr (t)
Power Generation @ 18,000 Btu/kwh	724 MBtu/Hr (t)
High Temp Process Heat	3296 MBtu/Hr (t)
	5380 MBtu/Hr (t)

W = % BY WEIGHT OF TOTAL CIRCULATION RATE
EXCLUDING MINIMUM FLOW BY-PASS.

AMOCO OIL CO.
1-24-75

Schematic of molten salt circulation system - 250,000 BCD refinery

250,000 BBL Refinery

Unit ULTRACRACKER														
Location				EXCHANGER SUMMARY						Page 1 of 7				
Exch. Unit No.	Exchanger Unit Name	Side	Fluid Circulating	Pressure, Psig			Temperature, °F			No. of Shells	Film Coefficient Btu/Hr/Ft ² /°F	Fouling Factor	Maximum Heat Flux Btu/Hr-Ft ²	Heat Duty MBtu/Hr
				DES	Oper Inlet	Test	DPS	In	Out					
U-1	Recycle Gas	Shell	HC Vapor		2300			667	862		300	.001	12000	152
		Tube	Salt					1100	960					
U-2	Recycle Oil	Shell	HC Liquid		2350			550	775		400	.003	10000	36
		Tube	Salt					1100	600					
U-3	Debutanizer Reboiler	Shell	HC Mixed Phase		300			508	631		450	.003	12000	202
		Tube	Salt					960	600					
U-4	Sputter Reboiler	Shell	HC Mixed Phase		30			487	605		400	.003	12000	194
		Tube	Salt					960	600					
		Shell												584
		Tube										Ultracracker Total		
		Shell												
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Unit ULTRAFORMER														
Location			EXCHANGER SUMMARY										Page 2 of 7	
Exch. Unit No.	Exchanger Unit Name	Side	Fluid Circulating	Pressure, Psig			Temperature, °F			No. of Shells	Film Coefficient Btu/Hr/Ft ² /°F	Fouling Factor	Maximum Heat Flux Btu/Hr-Ft ²	Heat Duty MBtu/Hr
				DES	Oper Inlet	Test	DPS	In	Out					
F-1	Ultrafiner Charge	Shell	HC Vapor		800			600	700		150	.002	12000	109
		Tube	Salt					970	880					
F-2	Ultraformer Charge	Shell	HC Vapor		400			750	950		250	.002	12000	292
		Tube	Salt					1100	800					
F-3	No. 1 Preheat	Shell	HC Vapor		375			788	970		250	.002	12000	253
		Tube	Salt					1100	850					
F-4	No. 2 Preheat	Shell	HC Vapor		350			873	970		250	.002	12000	140
		Tube	Salt					1100	950					
F-5	No. 3 Preheat	Shell	HC Vapor		325			899	970		250	.002	12000	103
		Tube	Salt					1100	950					
F-6	No. 4 Preheat	Shell	HC Vapor		300			946	980		250	.002	12000	51
		Tube	Salt					1100	1000					
F-7	Regen. Gas	Shell	Gas		350			460	1050		35	.002	12000	76
		Tube	Salt					1100	520					
E-4	Prefractionator Reboiler	Shell	HC Mixed Phase		20			468	480		350	.003	12000	116
		Tube	Salt					825	655					
E-9	Stripper Reboiler	Shell	HC Mixed Phase		275			507	520		400	.003	12000	129
		Tube	Salt					825	655					

American Oil Company

Unit ULTRAFORMER														
Location			EXCHANGER SUMMARY										Page 3 of 7	
Exch. Unit No.	Exchanger Unit Name	Side	Fluid Circulating	Pressure, Psig			Temperature, °F			No. of Shells	Film Coefficient Btu/Hr/Ft ² /°F	Fouling Factor	Maximum Heat Flux Btu/Hr-Ft ²	Heat Duty MBtu/Hr
				DES	Oper Inlet	Test	DPS	In	Out					
E-12	Debutanizer Reboiler	Shell	HC Mixed Phase		250			405	450		300	.003	12000	94
		Tube	Salt					825	655					
		Shell												1363
		Tube										Ultraformer Total		
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				DES	Oper Inlet	Test	DPS	In	Out					
H-1	Atmos. Heater	Shell	HC Mixed Phase		60			450	660		250	.004	12000	550
		Tube	Salt					775	640					
H-2	Vacuum Heater	Shell	HC Mixed Phase		4			610	795		150	.004	11000	400
		Tube	Salt					965	775					
		Shell												950
		Tube												
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Unit COKER														
Location			EXCHANGER SUMMARY										Page 5 of 7	
Exch. Unit No.	Exchanger Unit Name	Side	Fluid Circulating	Pressure, Psig			Temperature, °F			No. of Shells	Film Coefficient Btu/Hr/Ft ² /°F	Fouling Factor	Maximum Heat Flux Btu/Hr-Ft ²	Heat Duty MBtu/Hr
				DES	Oper Inlet	Test	DPS	In	Out					
C-1	Coking Heater	Shell	HC		25			680	930		100	.005	8000	160
		Tube	Salt					1100	820					
		Shell												
		Tube												
		Shell												
		Tube												
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Exch. Unit No.	Exchanger Unit Name	Side	Fluid Circulating	Pressure, Psig			Temperature, °F			No. of Shells	Film Coefficient Btu/Hr/Ft ² /°F	Fouling Factor	Maximum Heat Flux Btu/Hr-Ft ²	Heat Duty MBtu/Hr
				DES	Oper Inlet	Test	DPS	In	Out					
D-1	Distillate Heater	Shell	HC					450	700		350	.003	10000	106
		Tube	Salt					820	530					
D-2	FCU Feed Heater	Shell	HC					450	700		350	.004	10000	60
		Tube	Salt					820	530					
		Shell												
		Tube												
		Shell												
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American Oil Company

Unit FCU														
Location			EXCHANGER SUMMARY										Page 7 of 7	
Exch. Unit No.	Exchanger Unit Name	Side	Fluid Circulating	Pressure, Psig			Temperature, °F			No. of Shells	Film Coefficient Btu/Hr/Ft ² /°F	Fouling Factor	Maximum Heat Flux Btu/Hr-Ft ²	Heat Duty MBtu/Hr
				DES	Oper Inlet	Test	DPS	In	Out					
G-1	Feed Heater	Shell	HC Liquid					570	630		350	.004	12000	36
		Tube	Salt					1100	620					
G-2	Recycle Oil Heater	Shell	HC Liquid					550	660		350	.004	12000	37
		Tube	Salt					1100	620					
		Shell									FCU Total			73
		Tube												
		Shell												
		Tube												
		Shell												
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		Tube												

A-12

A-13

APPENDIX B
HYDROGEN AND PROCESS HEAT EXTENSION

SUMMARY

The application of a twin 2000 MW(t) HTGR has been briefly studied as a process heat source for:

1. Providing hydrogen and process heat for a crude oil refinery.
2. Providing hydrogen and electricity for a coal liquefaction unit.
3. Providing hydrogen and process heat for an oil shale liquids refinery.

The production capacity has been found to be 216,600 bbl of crude oil/day for a crude oil refinery, 173,950 bbl of coal liquids/day for the coal liquefaction plant and 155,200 bbl of syncrude/day for the oil shale facility.

With both reactors on line, each system will produce a considerable amount of excess electricity.

This investigation was based on one case of the main study (see Section 2.2). The following changes were made:

1. A parallel reformer-steam generator combination was added in the secondary helium loop upstream of the process heat exchanger. (For the coal liquefaction facility, this was omitted.)

2. The top temperature of the secondary helium loop was raised from 1300°F to 1600°F.
3. The primary coolant conditions were changed in accordance with item 2 above:
 - a. Core inlet temperature from 715.5°F to 851°F.
 - b. Core exit temperature from 1400°F to 1700°F.
 - c. Helium flow rate from 7.976×10^6 lb/hr to 6.43×10^6 lb/hr.

The higher temperature levels in the secondary helium loop make it possible to increase the thermal efficiency of the steam cycles and to produce refinery process heat at higher temperature levels. This should be the basis for a further study.

B.1. INTRODUCTION

At the request of ORNL, the current study has been extended with the following three cases.

1. An HTGR as a heat source for a crude oil refinery. The HTGR will provide process heat as described in the main study and heat for a hydrogen reformer. This reformer will provide for the total hydrogen requirements of the refinery, not replacing, however, that byproduct hydrogen normally produced in a refinery.
2. An HTGR as a heat source for the production of coal liquids. For this part the HTGR will be assumed at the mining site and will be used as the hydrogen source for coal liquid production.
3. An HTGR at a syncrude refinery to produce hydrogen and process heat for a refinery utilizing syncrude derived from oil shale as a feedstock.

All cases have been based on the operation of a dual 2000 MW(t) HTGR unit. Due to the limited time available, the three cases were studied on a scoping basis and the processes described below have not been optimized.

B.2. DESCRIPTION OF PROCESSES

B.2.1. Crude Oil Refinery

B.2.1.1.2. Basis of Design. For this case the refinery is assumed to require 0.447 MM Btu/bbl of process heat as described in Section 1. The hydrogen requirement will vary according to the type of crude. A value of 450 scf/bbl was found to be a reasonable average. In order to keep the unit at the reactor site as simple as possible, the minimum amount of equipment for the hydrogen plant was situated at the reactor site: two product feed exchangers, a steam generator, and the reformer. Further treatment of the reformer effluent, shift reaction acid gas removal and compression are assumed to be done at the refinery site. The reformer design is the one described in Ref. 18, except for the fact that it is situated outside the PCRV in the secondary helium loop.

B.2.1.2. Discussion of Results. A flow schematic is presented in Fig. B-1 and the data in Table B-1. The situation shown is for one reactor, assuming both reactors are on line. The feed for the hydrogen plant (stream 5), is assumed to be a hydrogen containing light hydrocarbon gas, such as for the example described in Ref. 31 which is comparable to the feed used in the study described in Ref. 18. This feed is heated to reformer inlet conditions in a feed-product exchanger (E11). Process steam for the reforming is generated from feed water in a product-feed exchanger (E12) and in the steam generator (E3). It is mixed with the feedstock before it enters the reformer.

Helium from the primary loop transfers the reactor heat to the secondary helium loop in heat exchanger E1. The secondary helium (stream 16) leaves E1 at 1600°F and is split into three streams (17, 19, and 23).

Fig. B-1. Crude oil refinery and oil shale oil refinery

TABLE B-1
CRUDE OIL REFINERY DATA

Stream No.	Flow (10 ³ lb/hr)	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Stream No.	Flow (10 ³ lb/hr)	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)
1	22765	167.5	625.8	0	28	7606		850	
2	11382	167.5	625.8	0	29	7606		869.5	
3	11382		1100	173.85	30	1696	1.1	105	73
4	22765		1100	173.85	31	1696	250	105.3	74
5	70.68	535	100		32	2053	100	327.8	298.4
6	35.34	515	1010		33	2053	700	329	301.1
7	216.03	515	1010		34	2053	650	674	1332.4
8	216.03		1240		35	2053	235	483	1255.1
9	216.03		1060		36	2053	220	754	1400
10	216.03	260	440		37	1154	190	750	1400
11	432.06	260	440		38	1154	20	332	1206.3
12	180.69	100	208.5		39	1899	220	754	1400
13	180.69		209.0		40	397.6-420.2	100	667	1363
14	180.69	570	479.5		41	375	100	667	1363
15	180.69	515	1010		42	22.6-45.2	100	667	1363
16	7606		1600		43	1696	1.1	105	1022.6-1009.1
17	313.4		1600		44	22.6-45.2	14.7	60	23.06
18	313.4		1219		45	1415	1.1	105	73
19	3489.6		1600		46	1415	320	105.5	74
20	3489.6		1562.4		47	1756	150	358.4	335.5
21	3803		1534.3		48	1756	3100	365.8	342.8
22	3803		1106.9		49	1756	3000	950	1404.8
23	3803		1600		50	1756	620	551	1254.2
24	3803		1502.2		51	1756	570	1002	1518.1
25	3803		1106.9		52	341	150	735	1394.2
26	7606		1106.1		53	1415	1.1	105	1030
27	7606		1076.1						

Stream 23, containing 50% of the total flow of stream 16, serves the steam cycle in heat exchangers E7 and E8. The other two streams (17 and 19), together with 50% of stream 16, first serve the reformer, E2, and the process steam generator, E3, then they are combined and deliver the heat for the process heat exchanger E4. Thereafter the two helium streams are recombined into stream 26 and in exchangers E5 and E6 generate steam for the "in-house power" loop as described in Section 2.2.

In the latter steam loop, some excess power is generated, in T3, and also some steam is used for feedwater heating of the reformer process steam: flow 42 with flow 44 as makeup.

As can be seen with respect to the base case described in Section 2.2, only two major changes have been introduced.

1. A parallel reformer-steam generator assembly is added in the helium loop upstream of the process heat exchanger.
2. The top temperature of the secondary helium loop is raised to 1600°F.

The refinery heat load increased on a unit feed basis and the refinery size had to be reduced from 250,000 bbl/day (Section 2.2) to 216,600 bbl/day (see Table 1-1). Also the amount of excess power produced by the system is reduced from 799.8/116 to 796/112 MW(e) because of the feedwater heating for the reformer (stream 42).

Since the highest temperature in the secondary loop is raised from 1300°F to 1600°F the temperature level in the primary helium loop will have to be raised as well. This is necessary in all three cases and will therefore be discussed separately in Section 11.3.

Raising the temperature in the secondary loop is required for the reformer where it was felt that the minimum practical process temperature

is 1400°F, although this deserves further study. Product-feed heat exchange in the reformer itself will reduce the reformer effluent temperature from 2400°F to 1240°F before the feed product heat exchanger. Obviously, raising the temperature of the primary loop and then of the secondary loop could result in a higher thermal efficiency. For this, however, the conditions in the power steam loop should be recalculated to a new optimum condition. However, the advantage of a higher thermal efficiency shall partly be offset by the increase in equipment cost due to the more severe steam conditions and increased cost in the primary cycle due to the fact that its temperature level will have to be raised as well. Since it was out of the scope of this study, the plant configuration has not been optimized. From the new mean temperature differences the new sizes of heat exchangers E7 and E8 have been estimated relative to those in the main study (see Table B-2). From this the advantage due to higher temperature level in the secondary loop can be seen. As can be seen, the exchangers in the steam loops decrease to 30%, 34%, 59%, and 53% for, respectively, E5, E6, E7, and E8. The size of the process salt heat exchanger E4 decreases to 36%. The latter decrease, however, is partly due to a 13% lower heat load as compared with the main case in Section 2.2.

TABLE B-2
NEW HEAT EXCHANGER SIZES

Exchanger No.	Relative Surface Area (%) (Base Case: Section 2.2 = 100%)
E4	36(a)
E5	30
E6	34
E7	59
E8	53

(a)

Partly due to a 13% lower heat load.

Alternatively the higher temperature level could be utilized by increasing the temperature level of the heat transport fluid and thus increasing the utility of this fluid in the refinery.

B.2.1.3.2. Recommendations. The plant configuration is not optimal. Further study is necessary to determine a more optimum use of the increased temperature in the secondary loop. This should also include a redesign of the reformer in such a way that the flow ratio of helium to reformer feed can be set so as to result in helium effluent temperature of the process steam generator. In this study the difference is 343.4°F.

In this case also the parallel setup of the reformer and the process steam generator should be re-evaluated and possibly be modified to be more efficient. A lower temperature in the secondary helium loop may be possible while maintaining the same reforming conditions.

The requirements of the refinery for process heat at a higher temperature level should be investigated, as the increase of the temperature of the secondary helium loop makes process heat delivery, for instance, at 1400°F possible.

An alternative approach for the improvement of this secondary cycle is the application of a gas turbine in the secondary cycle as a gas turbine-compressor unit will use the higher temperature heat more efficiently.

B.2.2. Coal Liquids Facility

B.2.2.1. Basis of Design. It is assumed that the coal liquids facility and the associated dual HTGR unit are situated at the coal mine. The HTGR will be used to produce the necessary hydrogen and electricity for the coal liquids plant. As a feedstock for the hydrogen plant, gas, and, if necessary, some of the coal liquids will have to be used.

The criterion for the liquid produced is that it should be pumpable to a distant refinery. There are various approaches in the production of liquids from coal and they are all based on the principle of adding hydrogen to the coal molecule. Reaction conditions, type of catalyst, and type of coal basically determine the yield of the liquid and gaseous products and their properties.

For the purpose of this study the Synthoil process (Ref. 32) was taken as a typical example. The hydrogen requirement (4245 scf/bbl gross produced) and the production figures are taken from Ref. 32.

For the electricity requirement, a figure of 33 kwh/t is used, which has been taken from Ref. 31.

It is assumed that the actual coal liquid plant is physically separated from the HTGR unit. Therefore, the hydrogen plant is assumed to be split in the same way as was assumed for the refinery study.

B.2.2.2. Discussion of Results. A block diagram showing the routing of the various streams and their magnitude is shown in Fig. B-2. A flow schematic of the streams at the HTGR unit is shown in Fig. B-3. One reactor is shown with both reactors on line. Table B-3 gives the data for Fig. B-3.

As can be seen from Fig. B-2, the feed for the hydrogen plant is a combination of off-gas from the reactor consisting of light hydrocarbons and hydrogen, pyrolizer off-gas consisting of hydrogen and methane, and of a fraction of the light ends. This stream will contain too high a sulphur content and must be treated in order to prevent poisoning of the reformer catalyst.

The layout of the part of the hydrogen plant at the HTGR site is identical to that in the refinery study, Section B.2.1. The reformer (E2) and the main process steam generator (E3) are in parallel lines in

Fig. B-2. Routing of streams in coal liquids facility

Fig. B-3. Streams at HTGR unit

TABLE B-3
COAL LIQUIDS FACILITY DATA

Stream No.	Flow (10 ³ lb/hr)	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Stream No.	Flow (10 ³ lb/hr)	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)
1	556	535	100		23	1696	250	105.3	74
2	278	515	1010		24	2053	100	327.8	248.4
3	1681.4	515	1010		25	2053	700	329	301.1
4	1681.4		1240		26	2053	650	674	1332.4
5	1681.4		1058.6		27	2053	235	483	1255.1
6	3362.8	260	440		28	2053	220	754	1400
7	1403.4	100	269		29	1154	190	750	1400
8	1403.4	570	480.7		30	1154	20	332	1206.8
9	1403.4	515	1010		31	899	220	754	1400
10	7606		1600		32	375	100	667	1363
11	2429.8		1600		33	220.6-441.1	100	667	1363
12	2429.8		1219		34	1696	1.1	105	904.9-773.8
13	1373.2		1600		35	220.6-441.1	14.7	60	28.06
14	1373.2		900.9		36	1415	1.1	105	73
15	3803		1600		37	1415	320	105.5	74
16	3803		1502.2		38	1756	150	358	330.5
17	3803		1106.9		39	1756	3100	365.8	392.8
18	7606		1106.9		40	1756	3000	950	1404.8
19	7606		1076.1		41	1756	620	551	1254.2
20	7606		850		42	1756	570	1002	1518.1
21	7606		869.5		43	341	150	735	1394.2
22	1696	1.1	105	73	44	1415	1.1	105	1036

the secondary helium loop. Two product feed exchangers are employed: E4 and E5. The process steam feed water heating system again used some steam from the in-house power steam loop (stream 33 with stream 35 as makeup).

With one exception, the secondary helium loop is identical to the one in the refinery study. Here no process heat is generated so the process salt heat exchanger is omitted. Also, the conditions in the primary helium loop are identical to those in the refinery study.

The dual 2000 MW reactor unit is capable of producing the hydrogen and electricity required for a 2259 t/hr 19.79×10^6 t/yr coal plant and will produce 173,950 bbl/day of coal liquids. When both plants are on line, the amount of excess electricity generated is 683 MW. When one reactor is off line no excess electricity will be generated, as shown in Table 1-1.

B.2.2.3. Recommendations. All the general recommendations made in Section B.2.1.3. concerning optimization with respect to the higher temperature level in the secondary helium loop are also valid for this configuration. The Synthoil process, which is used here, may not be the most suited process for combination with an HTGR unit because:

1. For hydrogen production a light fraction of the product must be used, which will have to be desulphurized in order to prevent poisoning of the catalyst.
2. The amount of hydrogen actually consumed per ton of coal is so little that the application of a twin 2000 MW(t) reactor results in a coal production rate of 19.79×10^6 t/yr. This would be a very large mine. Current mines are on the order of 2×10^6 t/yr.*

* On the other hand it is recognized that projected oil shale plants require mining operations which even surpass this size (24×10^6 t/yr) (Ref. 34).

It is conceivable that the coal liquefaction process could be modified in such a way that the coal liquids could absorb more hydrogen. A favorable result of this would be: (1) more methane will be produced which may make the use of light end liquid for reformer fuel unnecessary, and (2) the size of the mine will decrease. The extent to which coal liquids should be treated more with hydrogen largely depends on the market situation. Coal liquids are highly aromatic/naphthenic and are as such a valuable product; an increase in the hydrogen absorbed may decrease its value.

B.2.3. Oil Shale Liquids Refinery

B.2.3.1. Basis of Design. It was assumed that the refinery in this case would be a liquid that was derived from oil shale. The HTGR unit would be situated at the refinery and not at the mining site.

Several processes for the production of a "syncrude" from oil shale at the mine site have been proposed (see Ref. 34). In all cases the syncrude as produced is in general with respect to its hydrogen requirement in a refinery comparable to crude oil. Therefore the case for a refinery using this syncrude as a feedstock will be equal to the case presented in Section B.2.1 and will not be further dealt with here.

An alternative setup will be the treatment of the oil shale to produce products that can be transported through a pipeline. For this the Union Two process is a good alternative. It includes a combination of the Union Oil Company internal combustion retorts (Ref. 35) and circulating hot gas retorts (Ref. 36). Through judicious balancing of the relative amount of shale processed in each type of retort, fuel gas generated in the combustion retorts is used to heat the gas circulated through the recycle retorts (Ref. 37). This combination produces a high-Btu gas from the hot gas retorts and a crude shale oil, which is a combination from all retorts effluents. This crude product needs to be hydrotreated in order to convert it to a syncrude of reasonable quality. Transportation through a pipeline at elevated temperature for a short distance, however, is

conceivable. The process as described in this section is based on this principle: The crude shale oil and the retort off-gas are transported by pipelines to a refinery where the oil is hydrotreated with 1530 scf/bbl to yield a syncrude of 43 API gravity after which it will follow the normal crude oil refinery steps as mentioned in Section B.2.1.1: 450 scf H₂/bbl and 0.447 MM Btu/bbl. The off-gases produced by the hot gas retorting process would be used as a feedstock for the hydrogen plant.

B.2.3.2. Discussion of Results. Figure B-4 shows a block diagram of this process. It must be borne in mind that actually the hydroforming and refining processes will be integrated. These have been shown here separately to give a better insight into the basis of the calculations. As can be seen, a twin 2000 MW HTGR is capable of processing 155,200 bbl/day syncrude equivalent to 9405 t/hr of 34 g/t assay oil shale. The relevant mine size is about 82.4×10^6 t/yr which is 3.5 times as large as current proposals. However, the set up as chosen here offers the possibility to process the crude products of different mines at a central site. A flow schematic of the streams at the HTGR unit is shown in Fig. B-1. Table B-4 gives the values for this process. One reactor is shown assuming both reactors are on line.

As can be seen from Fig. B-4 no conceptual difference exists between this setup and the one for a crude oil refinery, Section B.2.1. The only difference exists in the magnitude of the heat loads of the hydrogen reformer (E2) and its matching process steam generator. This is due to the higher hydrogen requirements of crude shale oil. A further description of the process is therefore given in Section B.2.1.2 and a summary of the results is given in Table 1-1.

B.2.3.3. Recommendations. All the general recommendations made in Section B.2.1.3 concerning optimization with respect to the higher temperature level in the secondary helium loop are also valid for this configuration and will not be repeated here.

TABLE B-4
OIL SHALE FACILITY

Stream No.	Flow (10 ³ lb/hr)	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Stream No.	Flow (10 ³ lb/hr)	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)
1	16305	167.5	625.8	0	28	7606		850	
2	8153	167.5	625.8	0	29	7606		869.5	
3	8153		1100	173.85	30	1696	1.1	105	73
4	16305		1100	173.85	31	1696	250	105.3	74
5	261.4	535	100		32	2053	100	327.8	298.4
6	130.7	515	1010		33	2053	700	329	301.1
7	700.5	515	1010		34	2053	650	674	1332.4
8	700.5		1240		35	2053	235	483	1255.1
9	700.5		1035.3		36	2053	220	754	1400
10	700.5	260	440		37	1154	190	750	1400
11	1401.1	260	440		38	1154	20	332	1206.8
12	569.8	100	327.81		39	899	220	754	1400
13	569.8		328.8		40	490.4-605.8	100	667	1363
14	569.8	570	480.7		41	375	100	667	1363
15	569.8	515	1010		42	115.4-230.8	100	667	1363
16	7606		1600		43	1696	1.1	105	967.4-898.8
17	921.8		1600		44	115.4-230.8	14.7	60	28.06
18	921.8		1819		45	1415	1.1	105	73
19	2881.2		1600		46	1415	320	105.5	74
20	2881.2		1474.9		47	1756	150	358.4	330.5
21	3803		1412.9		48	1756	3100	365.8	362.8
22	3803		1106.9		49	1756	3000	950	1404.8
23	3803		1600		50	1756	620	551	1254.2
24	3803		1502.2		51	1756	570	1002	1518.1
25	3803		1106.9		52	341	150	735	1394.2
26	7606		1106.1		53	1415	1.1	105	1036
27	7606		1076.1

Fig. B-4. Shale oil production and refining with twin 2000 MW(t) HTGRs

B.3. REACTOR SYSTEM

The reactor system has already been described in Section 4.1. For the cases as described in this extension study, the conditions for the primary cycle will have to be changed to make a maximum temperature of 1600°F in the secondary loop possible.

Studies concerning higher core exit temperatures already have been reported (Ref. 18). Using these results the primary coolant conditions have been found to be:

Core exit temperature 1700°F

Core inlet temperature 851°F

Coolant flow rate 6.43×10^6 lb/hr.

As a result of this the pressure drops and thus the load on the primary circulator will be somewhat lower than for the base case. In the calculations, however, the higher value has been used.

B.4. CONCLUSIONS

1. This scoping study has shown that if a twin 2000 MW(t) HTGR would be used to provide for the process heat and/or hydrogen requirement of a crude oil refinery, a coal liquefaction plant, or a shale oil refinery, the sizes of these units would respectively be: 216,000, 173,950, and 155,200 bbl/day.
2. More work should be done regarding a more optimum use of the HTGR process heat in these cases.

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