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1170-MW(t) HTGR-SC/C APPLICATION STUDY REPORT: DIRECT STEAM RETORTING OF OIL SHALE

by
R. RAO

Prepared under
Contract DE-AT03-76SF70046
for the San Francisco Operations Office
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ABSTRACT

This report describes the application of a high-temperature gas-cooled reactor (HTGR) that operates in a steam cycle/cogeneration (SC/C) mode to supply process heat, process steam, and electricity for the recovery of oil from shale using a direct steam retorting process. Among all the surface retorting processes developed by the shale industry thus far, the direct steam retorting process has shown the highest yield of shale oil and release of hydrogen-rich off-gases (data primarily backed up by laboratory experiments). The technical and preliminary economic merits of integrating an 1170-MW(t) HTGR-SC/C plant with the direct steam retorting process are assessed, along with those of an indirect gas retorting process assisted by an HTGR-SC/C plant and the standard product oil/gas-fired heat source. The letter process was previously investigated by Davy McKee Engineers and Constructors in a study for GA Technologies Inc.

The energy requirements for a large commercial direct steam retorting process producing approximately 8,590 m^3/D (54,030 B/D) of hydrogenated oil were developed based on the design parameters selected by the process developer, Marathon Oil Company Research Division of Denver, Colorado, for a bench scale test. The assumed plant location for this present study is northwestern Colorado. Ten modular retorts provide approximately 2.68 x 10^6 Kg/h (70,000 T/D) of retorting capacity and yield a net of 8,590 m^3/D (54,030 B/D) of hydrogenated shale oil. All mining, process, and support facilities necessary for retorting oil shale are included in the process economics assessment. A heat balance/steam cycle diagram is included showing the integration of an 1170-MW(t) HTGR-SC/C plant with the process and the cogeneration of 257 MW(e) electric power.

A preliminary cost estimate of a commercial direct steam retorting plant shows a price of $41.08 (1983 $, 30-yr levelized) per barrel of upgraded shale oil for a 2005 plant startup of an 1170-MW(t) HTGR-SC/C plant

with a backup 1170-MW(t) HTGR-SC/C plant. The reference fossil fuel-fired process shows a cost of $49.58 (1983 $, 30-yr levelized) per barrel using a consistent set of economic ground rules with fuel valued at market price. The HTGR-SC/C plant appears technically and economically favorable, assuming a 30-yr reactor plant economic life. The gross thermal efficiency of the direct steam retorting shale oil plant, based on the higher heating value of the products, is 67%.

The environmental information developed indicates that using an HTGR as the primary energy source will achieve an overall plant reduction in atmospheric emissions of particulate matter, sulfur dioxide, and nitrogen oxides. Specifically, the combustion emissions from the conventional oil-fired boilers, the hydrotreater feed preheater, and the steam/power generation will be eliminated. All generated wastewater streams will be treated as necessary for reuse on site, for dust control, for spent shale moisturization, and for retorted shale disposal.

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1. INTRODUCTION

1.1. SHALE PROCESS INDUSTRY

Several surface retorting processes have been developed by the shale industry. The key to the commercial deployment of such a process depends upon several factors and issues pertaining to technical, financial, and institutional aspects. Specifically, the primary commercialization concern surrounds the process characteristics for maximizing the Fischer Assay value (high kerogen yield from the shale) and minimizing the cost of producing the synthetic fuel. While significant headway has yet to be made in achieving these goals, continuous efforts are being made by the shale industry to pave the way for commercial operation.

Commercial shale operations require considerable energy in the form of electric power, process heat, and process steam. In most of the shale retorting operations, this energy is provided by burning the product oil as fuel. The use of product oil as process fuel is significant; it not only decreases the net product yield substantially (by nearly one-third), but also severely impacts the cost of producing shale oil. This report investigates the feasibility of using an 1170-MW(t) high-temperature gas-cooled reactor - steam cycle/cogeneration (HTGR-SC/C) heat source in conjunction with a direct steam retorting process for the production of synthetic crude from oil shale.

A similar study performed by GA Technologies Inc. during FY 1982 investigated the feasibility of integrating an HTGR-SC/C plant to provide energy to a large 295 m^3/h (44,500 B/D) commercial, indirect shale surface retorting operation using hot recycle gas (Ref. 1-1). The results of that study favored the use of an HTGR plant for energy supply to the product-oil fired energy plant. A further investigation showed that pyrolyzing shale with low pressure superheated steam yielded more kerogen (Fischer Assay

value >100%) (Ref. 1-2) than retorting by hot recycle gas (Fischer Assay value <100%). The present study with direct steam retorting was thus initiated to assess the increase in synthetic crude production and accruable economic benefits.

Thus far, the extraction of oil from oil shale has not seriously been pursued the U.S. because of several technical and economic uncertainties. The key restraint is development cost, as evidenced by the Exxon Company's publicized decision to terminate its participation in the TOSCO Colony project. Various incentives will need to be offered by the federal government if private firms are to be induced to develop any future commercial synfuel projects.

Because large portions of the U.S. shale oil reserves, and certainly the richest deposits, are located in the Piceance Basin of northwestern Colorado, the initial commercial development is expected to start in this area. This report focuses primarily on a project in that area, although most of this work would be valid for any other western U.S. site.

1.2. SHALE SURFACE RETORTING

The shale contains hydrocarbon matter (kerogen) that is pyrolized to form combustible fluids and gases. Shale surface retorting is generally performed at the mine site, since it is uneconomical to transport large volumes of shale and at the same time resolve environmental problems concerning spent shale disposal and satisfy regulatory requirements.

Substantial quantities of water are required during several phases of the shale retorting process. The water use varies from steam/power production to dust control and revegetation. However, the regions containing shale deposits are generally arid and have limited water resources. In fact, water availability may be a key factor in determining oil shale project size.

1.3. HTGR-SC/C PLANT APPLICATION POTENTIAL

Davy McKee originally studied the feasibility of integrating an 850°C (1562°F) (reactor coolant outlet temperature) HTGR-process heat (HTGR-PH) plant with the indirect retorting (Paraho) process. (The Paraho description and the Davy McKee study details are presented in Ref. 1-3.) Based on the Davy McKee study, the application of an HTGR-SC/C plant with 750°C (1382°F) reactor coolant outlet temperature was examined for the indirect Paraho process, as reported in Ref. 1-1. A comparison with the conventional Paraho retorting process that uses product oil as its energy supply showed that integrating an HTGR plant conserved approximately one-third of the upgraded product oil produced [2,206 m^3/D (13,876 B/D*) out of 7,160 m^3/D (45,042 B/D)].

The HTGR, as a nuclear heat source, is uniquely suited for the shale surface retorting process because of its capability to provide high-temperature heat [up to 538°C (1005°F)], whereas the light water reactors are constrained by design to deliver heat at <315°C (600°F).

1.4. REPORT ORGANIZATION

Section 2 of this report describes the direct steam shale retorting process, including raw shale oil upgrading, the basis of the design, and major assumptions. Process energy requirements, the forms of energy, and heat recovery from spent shale are discussed in Section 3. Section 4 focuses on HTGR-SC/C plant integration with the oil shale retorting plant and HTGR steam cycle development. Preliminary plant economics are presented in Section 5. Section 6 covers issues relating to environmental impact and process water use and resources. A preliminary evaluation of an oil shale surface retorting project integrating an 1170-MW(t) HTGR-SC/C plant is given in Section 7.

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*B/D = barrels per day.

REFERENCES

1-1. Rao, R., "1170-MW(t) HTGR-SC/C Application Study Report: Modified Paraho Retorting of Oil Shale," DOE Report GA-A16811, October 1982.

1-2. Allred, V. Dean, "Considerations for Retorting Oil Shales with Superheated Water Vapor," 12th Oil Shale Symposium Proceedings, Colorado School of Mines, August 1979.

1-3. Davy McKee Engineers and Constructors, "Paraho Retorting of Oil Shale Using a Very High Temperature Reactor," NC-5757, 1980.

2. PROCESS DESCRIPTION

2.1. SHALE PREPARATION

Approximately 2.78 x 10^6 kg/h (73,640 T/D) of mined shale are crushed and screened to produce approximately 2.65 x 10^6 Kg/h (70,000 T/D) of prepared shale [pieces nominally measuring 10 mm x 7.6 cm (3/8 in. x 3 in.)] for the retorts. A general arrangement of the equipment system used for this operation is shown in Fig. 2-1. About 1.4 x 10^5 kg/h (3640 T/D) of shale fines [minus 10 mm (0.38 in.)] are returned with spent shale for disposal. The sized shale is fed to twin batteries that have five retorts per battery. Each retort is a refractory-lined cylindrical vertical kiln having a capacity of approximately 2.6 x 10^5 kg/h (700 T/D). Spent shale, along with shale fines, are disposed of in an environmentally acceptable manner.

2.2. BASIS OF DESIGN AND MAJOR ASSUMPTIONS

The grade and characteristics of shale assumed in this study refer to the shale deposits of northwestern Colorado or their equivalent. The assumed raw shale grade has a yield of 0.125 m^3/tonne (30 gal/ton) based on Ref. 1-2 and subsequent discussions with the process developer. Superheated steam conditions of 0.172 MPa (25 psia) pressure and 510°C (950°F) temperature selected for the retorting phase in Ref. 1-2 showed a Fischer Assay value of the recovered oil in excess of 100%. However, a conservative Fischer Assay value of 100% was assumed for the commercial operation presented in this study. (By comparison, the standard Paraho process has a Fischer Assay value of 93.5%.) The commercial operation further assumes that the recovered crude shale oil (kerogen) is upgraded on site by the hydrotreating process at a pressure of 15 MPa (2200 psia) and a temperature of 396°C (745°F) to remove sulphur, nitrogen, and oxygen to produce a synthetic crude having a nitrogen content less than 3000 ppm. Approximately 8,590 m^3/D (54,030 B/D) of hydrotreated shale oil flows to product storage.

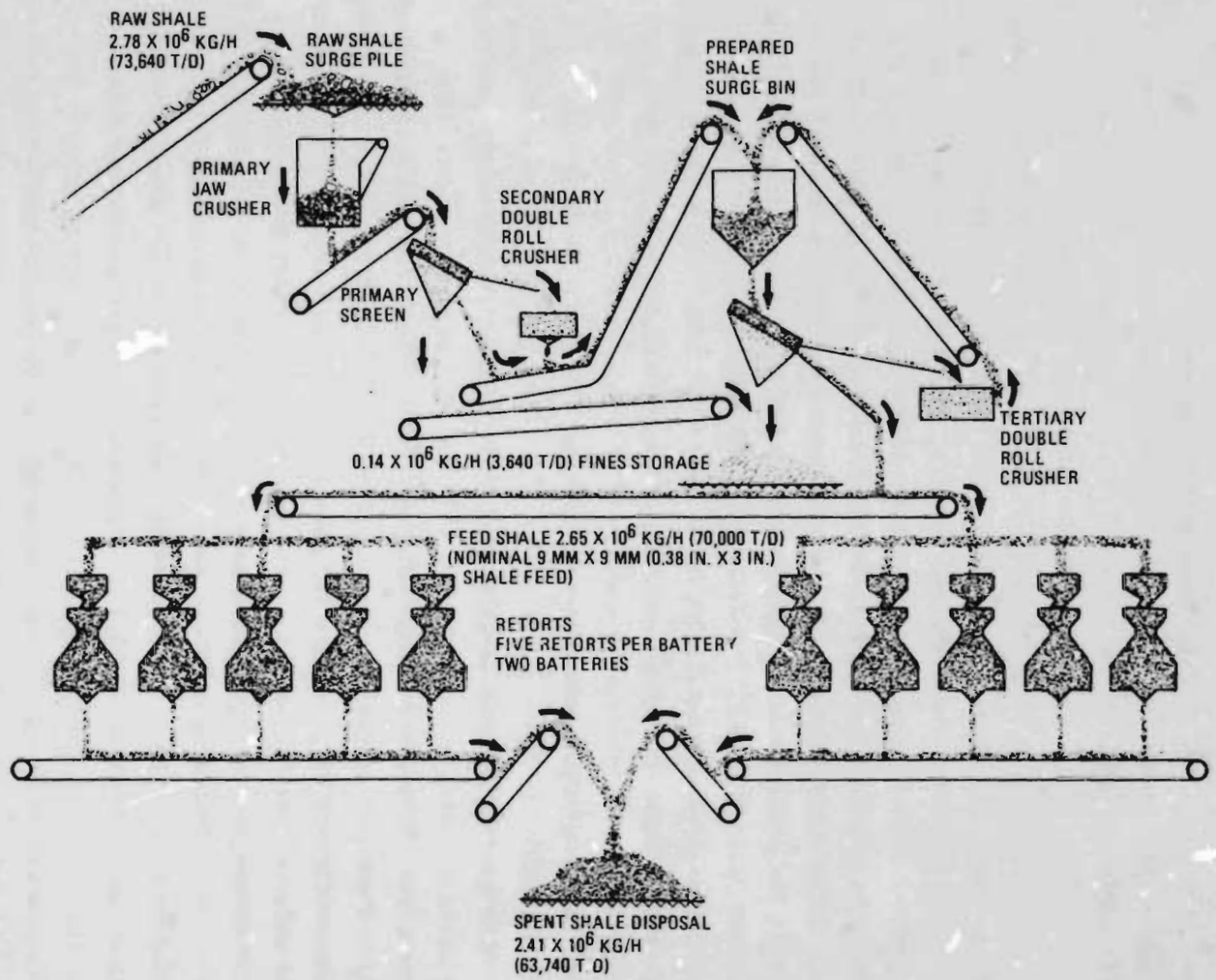


Fig. 2-1. Shale preparation and disposal scheme

Off-gas from the hydrotreater flows to an acid gas removal system. For this study, the retort kinetic characteristics of the direct steam retorting process were assumed to be the same as those given for the indirect Paraho process, which uses a hot recycle gas (Case III of Ref. 1-3). The height of the retorting zone and, consequently, that of the retorting vessel was increased by approximately 12% [from 6.7 m (22 ft) (Ref. 1-3) to 7.6 m (25 ft)] to accommodate the increased shale feed.

2.3. PROCESS DESCRIPTION AND COMMERCIAL OPERATION

The direct steam retorting process of oil shale was originally developed by the Marathon Oil Company Research Division of Denver, Colorado (Marathon). Based on the results of Marathon's laboratory experiments (Ref. 1-2), this process indicates the potential for substantially higher hydrogen-rich gas production and high shale oil yield and quality obtainable from lower retorting temperatures. Fischer Assay values in excess of 100% are predicted in the direct steam retorting process with several combinations of retorting pressure and temperature parameters. Additionally, from the environmental impact perspective, the system produces more environmentally acceptable retorted shales because the steam retorting process enhances the formation of silicates rather than alkaline earth oxides.

A process block flow diagram for the direct steam heated retort with major process parameters is shown in Fig. 2-2. In the direct steam retorting process, raw, sized shale enters ten direct heated vertical retorts having a total capacity of 2.65×10^6 kg/h (70,000 T/D). There it is pyrolyzed by passing and reacting with superheated steam vapor at superficial velocities between 0.5 m/s to 1.0 m/s (100 to 200 ft/min) and at temperatures of 510°C (950°F) or higher. Approximately 8,590 m^3/D (54,030 B/D) of hydrotreated shale oil flows to product storage.

Figure 2-3 shows the process arrangement for direct steam retorting of shale (in this diagram the primary heat is supplied from an 1170-MW(t) HTGR-SC/C nuclear heat source). The retort is a refractory-lined, vertical kiln that acts as a countercurrent, gas-to-solids heat exchanger.

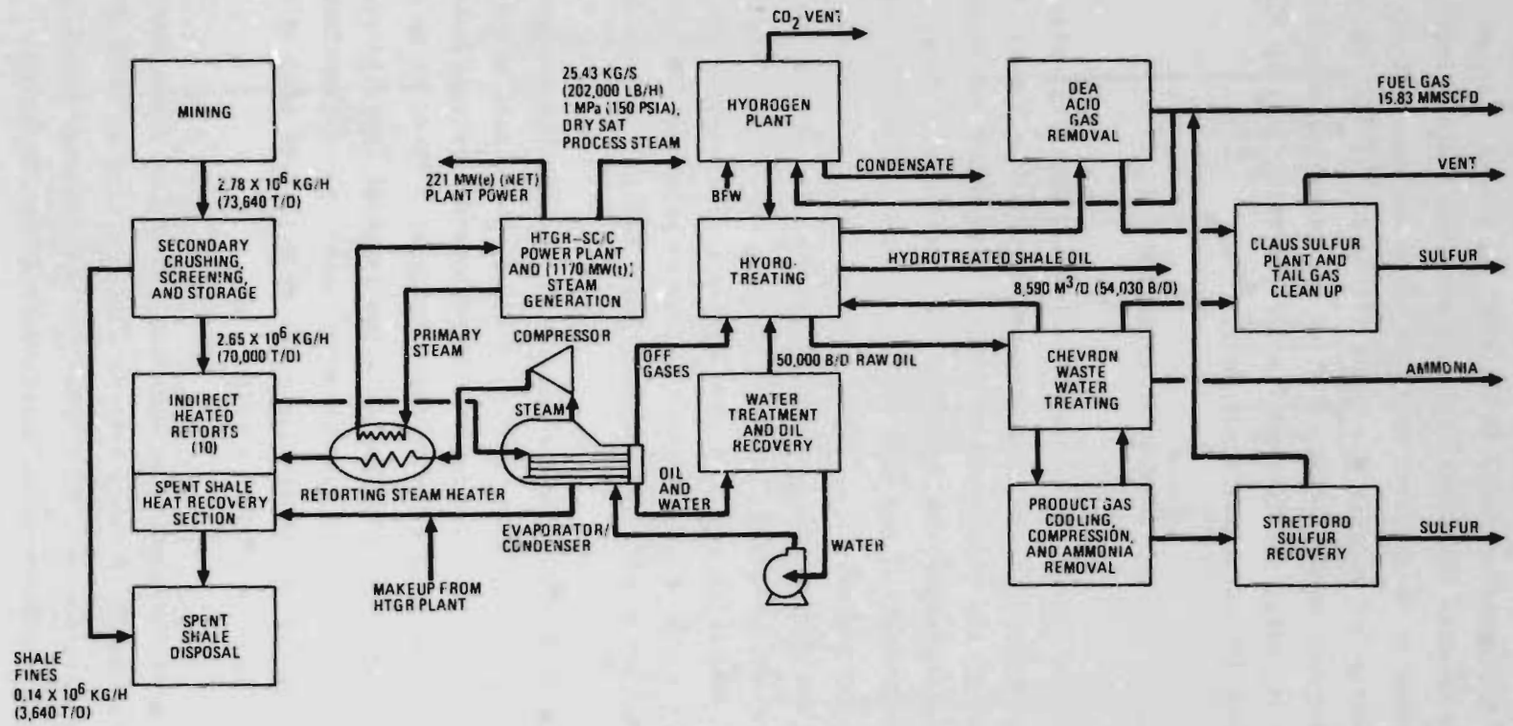


Fig. 2-2. Process block diagram for direct steam shale surface retorting with an 1170-MW(t) HTGR-SC/C plant

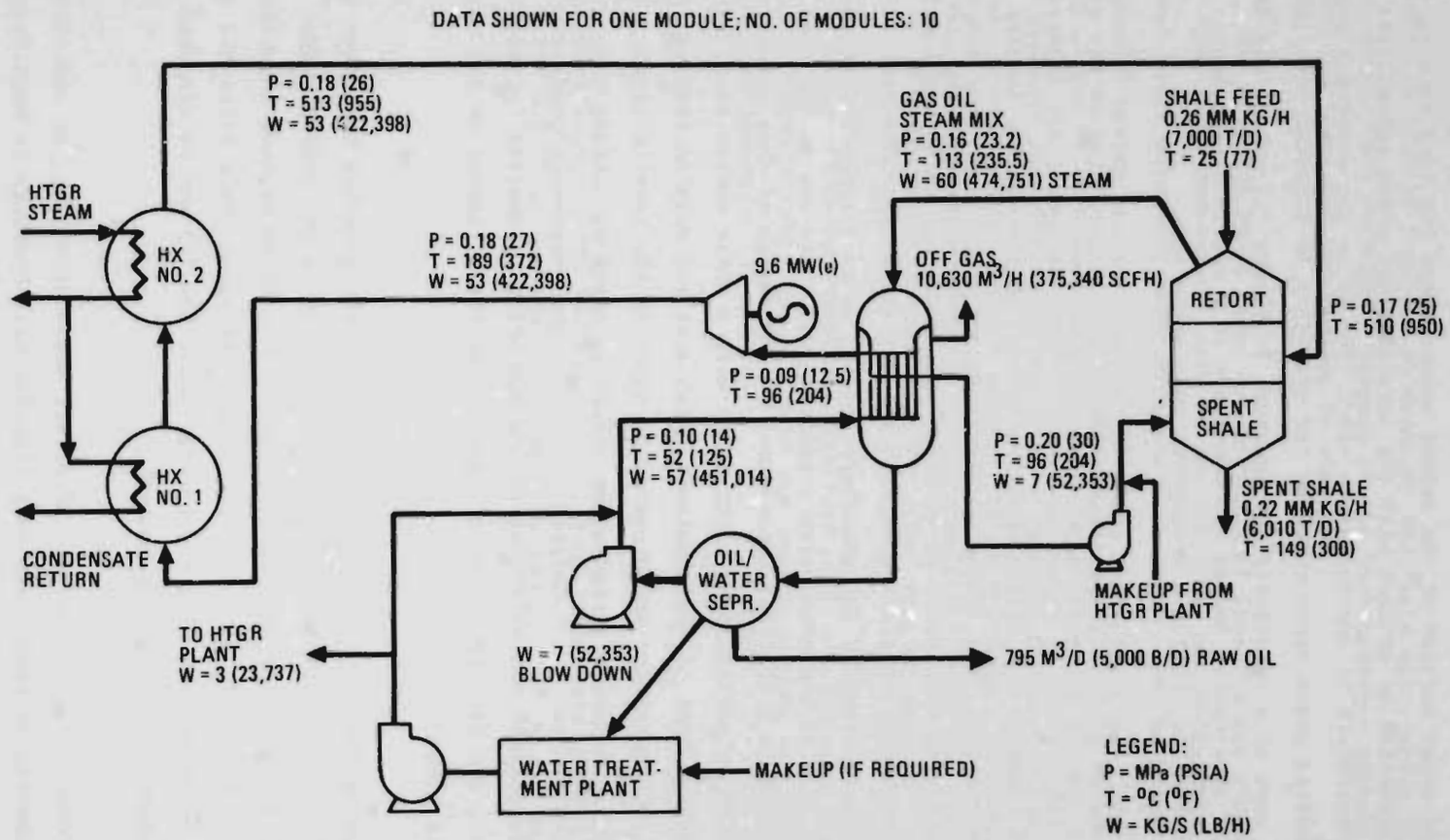


Fig. 2-3. Process arrangement for an 8,590 m^3/D (54,030 B/D) shale oil plant with direct steam retorting

In the upper section of the retort vessel where the feed enters, the shale is preheated by contact with the ascending hot steam and attains a surface temperature of approximately 483°C (900°F) in the retorting zone. The superheated steam vapor required for retorting is injected into the retorting zone at a relatively low pressure [0.17 MPa (25 psia)] and is circulated and alternately heated and condensed in a nearly closed loop. The kerogen within the oil shale decomposes into shale oil.

Because of a significant steam/carbon reaction occurring in the retort, hydrogen-rich (H_2 50% by volume in acid-free gas) off-gases are liberated in the retort vessel. The carbon monoxide content of the off-gas is also significantly reduced. The liberated off-gases and steam then carry droplets of shale oil from the retort to an evaporator/condenser unit in which the steam is condensed, separating it from the raw shale oil. The heat of condensation is absorbed by the secondary cooling water circulating in the evaporator side of the evaporator/condenser unit. The use of the condensing heat exchanger is a critical requirement in the design of this retorting system. This is particularly significant with a water system since water has a very high heat of vaporization, which must not only be removed in the condenser, but must also be recovered to vaporize the recycle steam. A commercial operation using direct steam retorting needs to achieve this step in an economical manner. A conceptual design of the evaporator/condenser unit and a discussion of the selection of its operating parameters (pressure, temperature, and flow rate), which have a significant impact on the unit design, are given in Ref. 2-1.

Following the retorting of the oil shale, the sensible heat from the retorted shale is recovered as the shale descends in the retort vessel through a stream of low-temperature steam. This steam becomes superheated and partly contributes to shale retorting. The spent shale exits the retort vessel at a temperature of approximately 149°C (300°F) and is disposed of in an environmentally acceptable manner.

The commercial implications of direct steam retorting, as indicated by the experimental research, are very significant. Hydrogen in significant

quantities will be required in treating the shale oil product to remove oxygen, sulfur, and nitrogen. Because of the high hydrogen content in the off-gases, the feed gas requirement is minimized.

The acid and basic gases can be scrubbed from the gas stream leaving a gas with large amounts of hydrogen and few other noncondensables. Conventional water scrubbing using stripped wash water from the Chevron wastewater treatment system removes residual NH_3 from the product gas. The sulfur content of the product gas is then removed by a Stretford sulfur recovery unit. The purified gas containing less than 1 ppmv H_2S flows to the hydrogen plant, providing feed for the manufacture of hydrogen. Following absorption of acid gas (carbon dioxide and hydrogen sulfide), high Btu gas [33.33 MMJ/m^3 (895 Btu/SCF)] is available for other uses or export.

Reference 1-3 describes the Stretford unit, the hydrogen plant, the Chevron hydrotreating unit, the acid gas removal system, and other auxiliary process equipment.

REFERENCES

2-1. Cavallaro, L. and Kaufman, J. S., "Heat Exchangers for Oil Recovery and Oil Shale Surface Retorting," GA unpublished data, July 1982.

3. PROCESS ENERGY REQUIREMENTS AND ENERGY SUPPLY FROM HTGR-SC/C PLANT

The direct steam shale surface retorting process is energy intensive, with the energy required to be steam, process heat, and electric power. Oil shale mining, crushing and screening, shale retorting, and oil upgrading operations are the major consumers of process energy. Since all phases of process operations are performed in remotely located shale oil fields, all forms of energy should be available on site. In the standard indirect shale retorting process (Ref. 2-1), both product oil and product gas are used as fuel to generate process heat, process steam, and steam for electric power generation on site. Energy required for mining, crushing, and spent shale disposal is provided by diesel-fuel-operated field equipment. This diesel fuel consumption is estimated to be 2.5 m^3/h (375 B/D) [~30 MW(t)].

Table 3-1 shows energy requirements by form at various phases of a commercial shale retorting operation processing 2.65 MMkg/h (70,000 T/D) of shale. Most of the energy generated is used for shale retorting, followed by hydrogen production and mining operations. The thermal energy requirement shown for shale retorting is exclusive of the heat recovered from retorted shale. The electric power requirement is considerable for shale retorting and oil recovery operations, mining, hydrotreating, and compressing retorting steam. The total power requirement for the steam compressors is estimated to be 96 MW(e), and the compressors are large in order to handle a large volume of steam vapor at low pressure. Table 3-2 shows a detailed breakdown of electric and process steam requirements totaling 240,888 kW and 25.45 kg/s (202,000 lb/h), respectively. Dry, saturated process steam at 1 MPa (150 psia) is required to be supplied by the HTGR plant. A small portion of the required process steam is generated internally in the process and can be extracted from the hydrotreating unit and the Claus and Scot sulfur recovery unit (Ref. 1-3).

TABLE 3-1
ENERGY REQUIREMENTS FOR AN 8,590 m^3/D (54,030 B/D)
(REFINED OIL) DIRECT STEAM RETORTING PROCESS

	Process Requirement MW
1. Steam for retorting Pressure: 0.17 MPa (25 psia) Temperature: 510°C (950°F) Flow rate: 53.18 kg/s (422,400 lb/h)	372.0
2. Process steam Pressure: 1 MPa (150 psia) dry sat. Flow rate: 25.43 kg/s (202,000 lb/h)	67.0
3. Hydrotreater	13.0
4. Hydrogen plant	205.0
5. Electric power	
Process	145.0
Steam compressors	96.0
Total	898.0

TABLE 3-2
ELECTRIC AND PROCESS STEAM REQUIREMENTS
FOR AN 8,590 m^3/D (54,030 B/D) (REFINED) SHALE OIL
PLANT WITH DIRECT STEAM RETORTING

Section	Power (kW)	Steam[a] kg/s (lb/h)
Mining	28,543	
Secondary crushing and screening	6,848	
Retorting and oil recovery	69,771	
Spent shale disposal gas cooling, compression, and NH_3 removal	1,268	
Stretford plant	4,678	0.54 (4,320)
Waste water treating	3,000	
Hydrotreating	19,396	[(3.49) (27,750)]
Hydrogen plant	10,372	
DEA acid gas removal	168	1.27 (10,080)
Claus and Scot plants	168	[(0.74) (5,900)]
Chevron waste water treatment	576	22.96 (182,400)
Shale oil storage		4.91 (38,850)
Steam compressors	96,100	
Total	240,888	25.45 (202,000)

[a] 1 MPa (150 psia) dry, saturated.

The overall process thermal efficiency was estimated to be 67%.

Figure 3-1 shows the temperature versus heat (T-Q) diagram for the process thermal heat load. Approximately 69% of the thermal heat load is required at a temperature $\leq$538°C (1000°F). The high-temperature energy [>538°C (1000°F)] extends up to 790°C (1450°F); this constitutes approximately 31% of the total thermal heat load.

In the conventional surface shale retorting process, about one-third of the gross product yield is consumed as fuel in the plant to provide the process thermal and electric power.

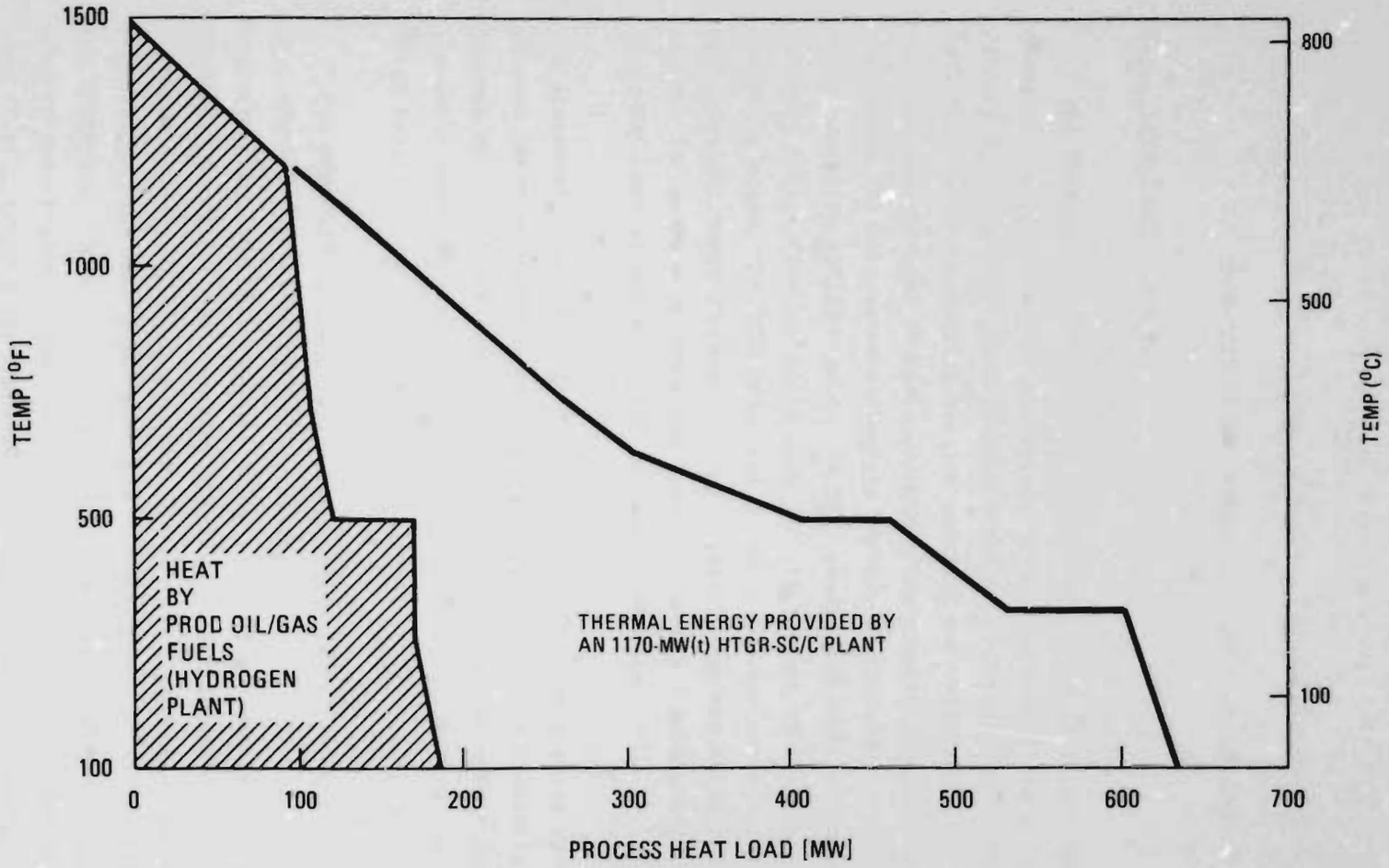


Fig. 3-1. Temperature vs heat load diagram for an 8,590 m^3/D (54,030 B/D) refined shale oil plant using direct steam retorting

4. HTGR-SC/C PLANT INTEGRATION AND HEAT BALANCES

4.1. INTEGRATED PLANT DESIGN

The HTGR-SC/C plant provides process steam and electric power to the commercial shale retorting operations using superheated steam for retorting. Primary steam exiting the HTGR-SC/C plant at 17.34 MPa/540°C (2515 psia/1005°F) is used for heating the low pressure retorting steam and is then expanded though power turbines, cogenerating electric power. The exhaust steam from the intermediate pressure turbine is adjusted to meet the process steam condition and flow rate. In this study, the heat cycles were so arranged that, after providing heat for the heating of the low pressure retorting steam, the HTGR steam was expanded through power turbines to maximize electric power production. Any primary steam remaining in excess of its use for process purposes was expanded through a condensing turbine-generator unit to enhance electric power production.

Integration of an HTGR-SC/C plant with the direct steam retorting process provides the process energy and conserves a considerable amount of product oil by effectively replacing the use of approximately one-third of the daily production of shale oil [2,544 m^3/D (~16,000 B/D)] as fuel oil, which also includes power generation.

The HTGR-SC/C plant primary steam, which is delivered to the process at 17.3 MPa/540°C (2415 psia/1005°F), provides the heat for the retorting and hydrotreating, and also supplies steam required at various stages of the process. Surplus steam from the HTGR-SC/C plant is expanded through power turbines, cogenerating electricity. However, the hydrogen plant also requires process heat [~205 MW(t)] at a temperature of 787°C (1450°F), which the HTGR-SC/C plant cannot provide. Fossil fuel (product oil and gas) is used to supply this process heat, as shown in the temperature versus heat load diagram (Fig. 3-1). Approximately 75% of the total energy

demand-electric power, process heat, and process steam of the 7,950 m^3/D (50,000 B/D crude) direct steam retorting shale oil plant is provided by a single 1170-MW(t) HTGR plant.

The HTGR-SC/C plant for this application would be located in relatively remote parts of Colorado. The HTGR-SC/C plant can be sited relatively close to the retorting plant so that process steam transmission distances and, therefore, steam pressure losses would be modest.

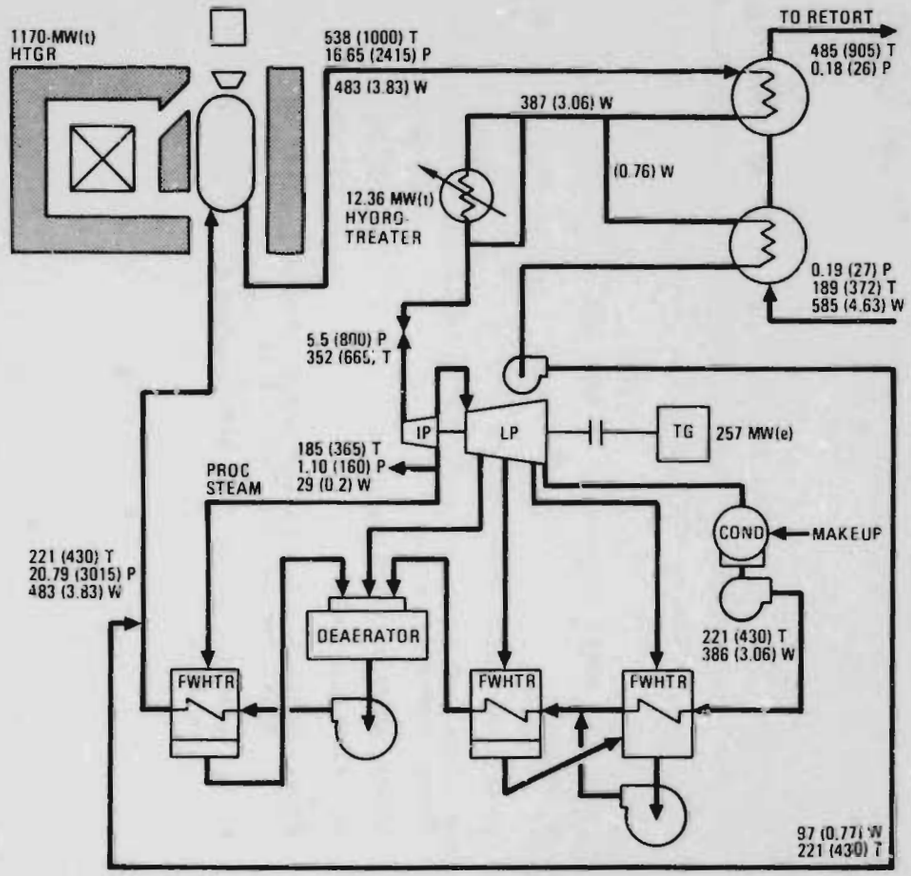
4.2. NUCLEAR STEAM SUPPLY (NSS) DESIGN

The HTGR-SC/C is a high-efficiency system, as described in Ref. 4-1. The 1170-MW(t) NSS used in this study to provide steam energy for the process plant is a modular unit containing the reactor core and two steam generator/helium circulator loops within a thick-walled, multicavity, prestressed concrete pressure vessel that functions as the primary containment and biological shielding for the reactor and primary coolant system.

A separate, auxiliary heat-removal system with its own heat exchangers and helium circulators is also located in the prestressed concrete reactor vessel (PCRV). The PCRV and auxiliary systems are housed inside a conventional, steel-lined, reinforced-concrete containment building. Flexibility in the process steam temperature and pressure conditions from an HTGR used in a cogenerating mode provides the necessary conditions to meet the requirements of this process application.

4.3. HEAT CYCLE

Figure 4-1 shows the HTGR-SC/C heat cycle for the direct steam retorting process. This heat cycle uses split heat exchangers to heat the process retort steam from 189°C (372°F) to 513°C (955°F). On the HTGR NSS primary steam side, steam is desuperheated, condensed, and subcooled. The drain temperature of the condensate was selected to match the feedwater temperature requirement of the HTGR steam generators. The heat exchangers



ALLOCATION OF REACTOR POWER OUTPUT	MW	%
PROCESS USES		
STEAM POWER TO PROCESS	438	37
ELECTRIC POWER	221	19
AUX POWER	35	3
CONDENSER	470	40
LOSSES	6	1
TOTAL REACTOR POWER OUTPUT	1170	100

LEGEND:
W = FLOW KG/S (10^6 LB/HR)
P = PRESSURE MPa (PSIA)
T = TEMPERATURE ^{0}C (^{0}F)

Fig. 4-1. 1170-MW(t) HTGR-SC/C steam cycle arrangement for an 8,590 m^3/D (54,030 B/D) refined oil direct steam shale retorting process

were assumed to be located about 0.8 km (0.5 mile) from the reactor plant, and a 0.34-MPa (50-psia) pressure loss in transmission piping was estimated. That pressure loss, combined with a piping heat loss of about 1.75 MJ/kg (0.75 Btu/lb) of steam, results in a steam temperature of ~536°C (996°F) at the HX 2 inlet.

Also shown in Fig. 4-1 is the extraction of 25.45 kg/s (202,000 lb/hr) of steam at 1.1 MPa (160 psia) from the turbogenerator (TG) for process use. Additionally, some steam from the HX 2 outlet is used in the hydrotreating process to heat fluid from 368° to 396°C (695° to 745°F). That heat load was specified to be 12.36 MW(t).

Steam at the TG inlet is throttled after it leaves the heat exchangers in order to limit turbine exhaust moisture to the same level as in the straight steam cycle turbines, which have 16.65 MPa/538°C (2415 psia/ 1000°F) steam at the inlet.

The TG unit generates a net electric power of 221 MW(e), which is slightly less than the process requirement of 241 MW(e) (Table 3-1). This deficit is supplied by a backup HTGR plant and part-time by the grid.

The net electric power produced from the 1170-MW(t) HTGR-SC/C plant is summarized as follows:

	KW(e)
Gross generator output	256,000
Less: HTGR auxiliary power	-35,000
Net electric power	221,000
Note: Shale plant electric power requirements (See Table 3-1)	241,000
Electric power from backup plant or grid	20,000

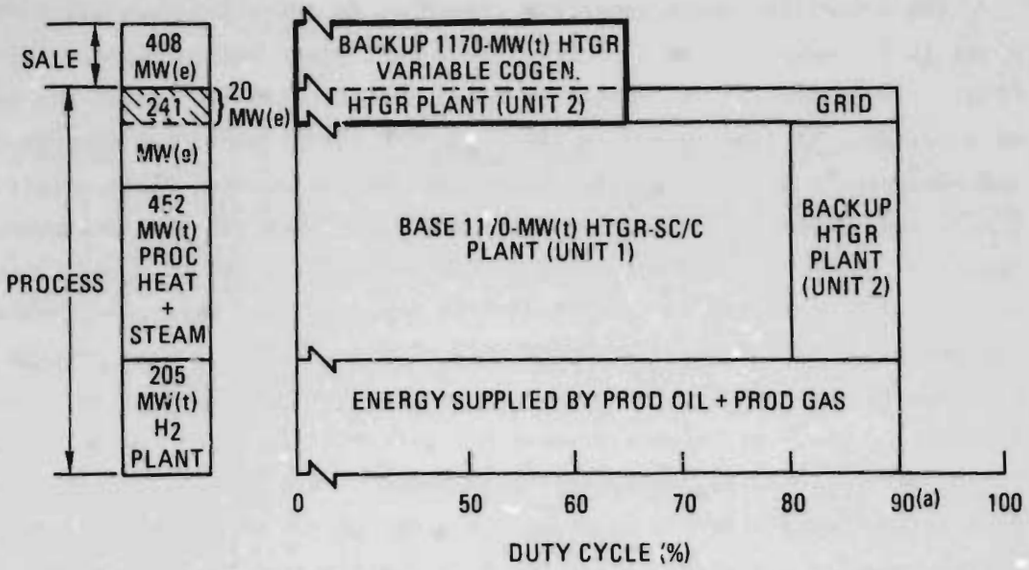
4.4. BACKUP HTGR PLANT

The commercial shale retorting plant has an operating capacity (90%) which is in excess of the 1170-MW(t) HTGR-SC/C plant design capacity factor (80%). Therefore, an 1170-MW(t) variable cogeneration HTGR plant was added as a backup. It functions like the HTGR-SC/C plant, providing process steam and electricity for 10% capacity (thus meeting the process plant requirement), and generates 428 MW(e) of sole electric power for the remaining 65% capacity. (The variable cogenerator HTGR plant has a design capacity factor of 75% while operating in an all-electric power mode.) Figure 4-2 shows the operation of the two 1170-MW(t) HTGR plants relative to the process plant operation. Figure 4-2 includes a table showing the sale and purchase of electric power at various process plant operating capacities. The electric power for sale is considered "firm power" if an amount of power specified is made available for sale for a minimum of 75% of a specified time period (usually one year); otherwise it is considered "non-firm power." The sale price varies depending on the case. The backup plant supplies the deficit 20 MW(e) required by the process for 65% capacity, and the grid supplies for the balance 25% capacity.

For comparison, an alternative case using an oil-fired backup plant was considered. Figure 4-3 shows the operation of the oil backup plant relative to the process plant. In order for the oil backup plant to be readily available and respond to the process plant full-load energy demand, it was assumed to be operating at a minimum 10% full load while idling.

REFERENCE

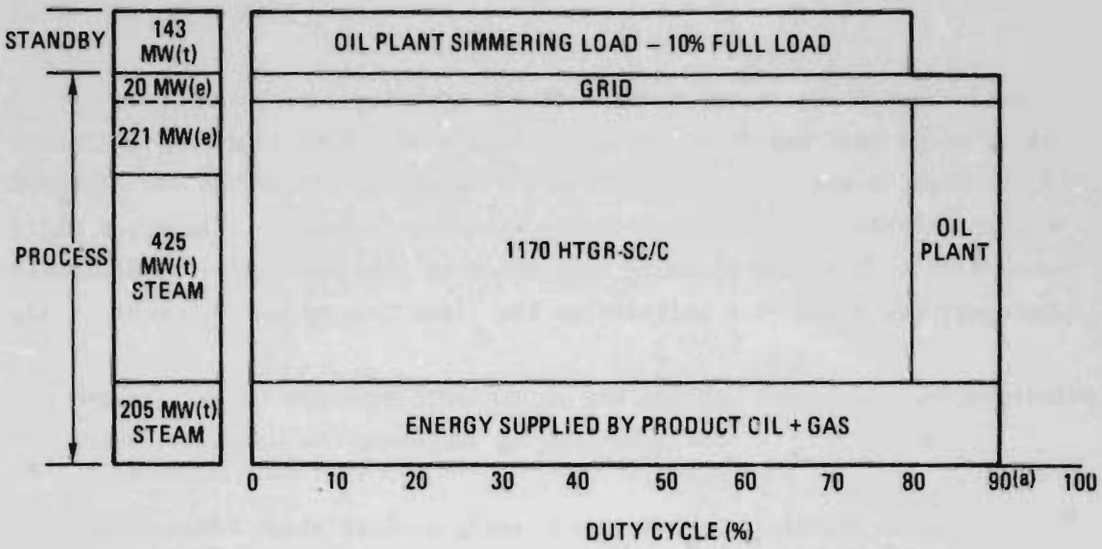
4-1. "1170-MW(t) HTGR Steamer Cogeneration Plant NSSS Design Report," DOE Report GA-A15222, August 1980.



(a)PROCESS PLANT REQUIREMENT

	HTGR CAPACITIES		
	0-65%	65%-80%	80%-90%
DUTY CYCLE (%)	65	15	10
BASE HTGR-SC/C PLANT [MW(t)]	1170	1170	–
BACKUP HTGR PLANT [MW(t)]	1170	–	1170
ELECTRIC POWER			
SALE	408	–	–
PURCHASED	–	20	20

Fig. 4-2. 1170-MW(t) HTGR plants direct shale retorting process with a backup HTGR plant



(a)PROCESS PLANT REQUIREMENT

	HTGR CAPACITIES	
	0 – 80%	80 – 90%
DUTY CYCLE	80	10
HTGR-SC/C [MW(t)]	1170	–
BACKUP OIL PLANT [MW(t) INPUT]	143	1427
ELECTRIC POWER PURCHASED [MW(e)]	20	20

Fig. 4-3. 1170-MW(t) HTGR plant with oil-fired plant backup for direct steam shale retorting

5. ECONOMICS

5.1. COST ESTIMATES

A preliminary cost estimate was made for a commercial direct steam retorting operation to obtain a cost comparison with the Davy McKee study based on the indirect recycle gas retorting operation (Paraho) using HTGR-PH [then known as very high-temperature reactor (VHTR)] and HTGR-SC/C reactor plants (Ref. 1-3). The process plant cost estimate was derived or extrapolated from Davy McKee cost data, and no detailed cost input was prepared.

Highlights of the Davy McKee basis and general terms used in developing the plant economics are presented in this section.

The capital costs include plant investment, engineering services, construction expenses, contingency, and working capital. A preliminary capital cost was developed based on such information as process flow diagrams, major equipment sizes, in-house pricing for process packages, budget prices based on other similar projects, and published cost data.

For determining direct capital costs of major plant sections, the six-tenths exponent rule was applied to the scaling of plant capacities. The Chemical Engineering Plant Cost Index escalation factors were used as a method to update plant costs. Single-source quotations from previous studies were used to determine the costs of major equipment such as furnaces, compressors, turbogenerators, towers, heat exchangers, and pumps. Recommended exponents were used for scaling equipment costs, and the Marshall and Swift Equipment Cost Index was used to update the costs. All costs were based on January 1, 1980 dollars and were updated to 1983 dollars with appropriate escalation factors. Power plant cost for the 1170-MW(t) HTGR-SC/C plant was developed by GA Technologies Inc. (GA) in cooperation with United Engineers & Constructors and formed the basis for the cost study.

Systems and components were modified to suit the direct steam shale retorting process application design requirements. These systems and components included structures and improvements and equipment pertaining to the reactor plant, the turbine plant, the electric plant, and other related components. All costs are expressed in January 1, 1983 dollars.

Table 5-1 shows itemized capital costs for a 2.78 x 10^6 kg/h (73,640 T/D) shale process plant. An equilibrium HTGR-SC/C plant was assumed in the economic analysis.

5.2. ECONOMIC ANALYSIS

5.2.1. Methodology

The revenue requirement method (Ref. 5-1) was selected as the method for evaluating the alternative projects. This technique, which is commonly accepted by the electric utility industry for evaluating long-lived power plant projects, determines the revenue needed by the firm as compensation for all expenditures, fixed and variable. Hence, the revenue requirements of the firm are the costs to the consumer of the process steam cogenerated.

Under the revenue requirement technique, the concept of levelization is used to convert a stream of escalating costs to a single level cost stream, or equal payment annuity. Such a technique explicitly accounts for the time value of money to the firm (discount rate), the escalation (inflation) rate, and the life of the project.

Base year capital costs are escalated through plant construction, and interest during construction is added to arrive at a total capital cost in commercial operation year dollars. A fixed charge rate is applied to the total capital cost to arrive at an annual fixed charge to which are added the levelized annual fuel costs, levelized annual operation and maintenance (O&M) costs, and a credit for the levelized value of cogenerated power, to arrive at a total levelized annual cost.

TABLE 5-1
DIRECT STEAM RETORTING - COMMERCIAL PROCESS PLANT
ITEMIZED CAPITAL COST [2.78 x 10^6 kg/h (73,640 T/D) MINED SHALE; 8,590 m^3/D (54,030 B/D) GROSS OIL YIELD]

NOTE: ALL $ IN JANUARY 1980 $ UNLESS OTHERWISE NOTED

	$
Mining	123
Secondary crushing and screening	70
Retorting and oil recovery[a]	274
Spent shale disposal	25
Gas cooling, compression and ammonia removal	3
Stretford plant	11
Wastewater treating	9
Hydrotreating	82
Hydrogen plant	44
DEA acid gas removal	2
Claus and Scot plants	4
Chevron wastewater treatment	14
Shale oil storage	10
Power plant	--
Water supply	11
Offsites[b]	76
Total direct costs	758
Other costs:	
Engineering services[c]	114
Construction expense[d]	152
Contingency[e]	181
Total indirect costs	447
Fixed capital investment	1205
Working capital[f]	196
Total capital investment	1401
Total capital investment in 1983 $[g]	1732

[a] Includes $40 million for evaporator/condenser units, steam compressors, pressure seal systems for the retort vessel, booster pumps, and oil/water separator unit.

[b] Offsites are 10% of the total direct costs.

[c] Engineering services are 15% of the total indirect costs.

[d] Construction expenses are 20% of the total indirect costs.

[e] The contingency factor, which provides an estimating allowance, is taken as 15% of the fixed capital investment.

[f] The working capital, which includes plant start-up, prepaid royalties, environmental monitoring, organizational development, operating expenses, catalysts and chemicals and product inventory, is 14% of the total capital investment.

[g] Escalation is 9% through 1982 and 4% to 1983.

5.2.2. Assumptions

Table 5-2 shows the economic assumptions used in this study. Table 5-3 shows the financial assumptions employed in the study. The economic analysis was based on private industries ownership for the process plant and utility ownership for the energy plants. Oil and gas used as fuel in the hydrogen production plant were assumed purchased at the world market price. An additional economic analysis in which the use of oil and gas as fuel was deducted from the gross plant product yield was considered for illustration. In this case, the product price was determined on the basis of net product yield.

The economic assumptions shown in Table 5-2 were established by GA in cooperation with Gas Cooled Reactor Associates. Although these ground rules are consistent with private industry practice, they are subject to modification by a specific developer. Additional economic advantages, if any, depend on the ground rules of a specific developer.

5.3. RESULTS

Table 5-4 shows the economic results for the direct steam retorting process using an 1170-MW(t) HTGR-SC/C plant with two backup plant options: (1) a variable cogeneration HTGR plant and (2) an oil-fired plant. Table 5-5 shows the results of the Davy McKee economic study (Ref. 1-3) performed on a similar basis for the indirect gas retorting process, which included an 1170-MW(t) HTGR-PH (VHTR) plant (oil backup), an 1170-MW(t) HTGR-SC/C plant (HTGR or oil backup), and the standard Paraho plant. The standard Paraho plant consumes a considerable amount of fuel oil (nearly one-third of gross output) in the power plant. Therefore, on a purchased basis, the cost of fuel oil for the standard Paraho process is significantly higher than the HTGR nuclear fuel cost either for the indirect gas or for the direct steam retorting process, as shown in Tables 5-4 and 5-5.

TABLE 5-2
ECONOMIC ASSUMPTIONS

Commercial plant basis	N^{th} plant
Capacity factor	90%
Base date for all costs	January 1983
Date of operation for all plants	January 2005
Investment life for all plants	30-yr
Credit value for electric power [Mills/kW(e)-h]	53[a], 84[b], 33[c]
2005 fuel cost projections (January 1983 $)	
Uranium	$111.00/kg ($50/lb) U_3O_8
Conversion	$3/kg UF_6
Separative work (0.2% tails)	$140/SWU
Nuclear fuel cycle	LEU/Th once through $1.30/GJ ($1.37/10^6 Btu)
Oil/gas	$8.82/GJ ($9.30/10^6 Btu)

O&M costs (January 1983 $)	Fixed (10^6 $/yr)	Variable [mills/kW(t)-h]
HTGR-SC/C single/twin	40.0/60.0	0.30
Nat. gas (central station) single/twin	4.0/6.0	0.30

Common cost factors	Percent (%)
Weighted cost of capital	5.4
Levelized fixed charge rate (utility/industry)	8.5/13.7
Allowance for funds during construction (utility/industry)	4.4/8.5
Real escalation rates (%)	
General	0.0
Electric power	0.5/1.0
Natural gas/oil	1.5
Indirect & contingency factors (single/twin)	
Const. serv. & field eng. (% of direct costs)	25.0/20.0
Eng. serv. & fees (% of total field costs)	15.0/12.0
Contingency (% of field cost & eng. serv.)	10.0/10.0
Owner's cost (% of total plant investment)	5.0/3.0

---

[a] Sale - firm.
[b] Purchased.
[c] Non-firm.

TABLE 5-3
FINANCIAL ASSUMPTIONS
(ASSUMING ZERO INFLATION RATE)

Marginal tax rate	50%
Investment tax credit	8%
Property taxes	
Constant fixed charge rates (FCR)[a] adder	1%
Inflated FCR adder	2%
Yearly capital replacement	
Constant FCR adder	1%
Inflated FCR adder	2%
Book life (years)	30
ACRS depreciation per ERTA 1981, as amended by TEFRA 1982 (150% declining balance used as an approximation)	
Tax life (years):	
All cogenerators	10
Fossil electric or steam	15
Nuclear electric	10
Nuclear decommissioning	Sinking fund at 8% of initial capital cost

[a] FCR were determined using the above financial factors.

TABLE 5-4
ECONOMIC ANALYSIS FOR A COMMERCIAL 8,590 m^3/D (54,030 B/D) HYDROGENERATED SHALE OIL PLANT WITH DIRECT STEAM RETORTING PROCESS

NOTE: ALL $ IN 1983 CONSTANT $ UNLESS OTHERWISE NOTED

	Energy Plants				
	Option One		Option Two		
	Primary	Backup	Primary	Backup	
	HTGR-SC/C (N^{th} plant)	Oil Plant	HTGR-SC/C (N^{th} plant)	HTGR-SC/C (N^{th} plant)	Process Plant
Ownership	Utility	Utility	Utility	Utility	Industry
Plant parameters					
Feed shale, MMkg/h (T/D)					2.65 (70,000)
Thermal rating (input), MW(t)	1170.0	1427.0	1170.0	1170.0[a]	
Heat input to the cycle, MW(t)	1170.0	1170.1	1170.0	1170.0	
Gross electric output, MW(e)	256.0	256.0	256.0	464.0/256.0	
Net electrical output, MW(e)	221.0	221.0	221.0	428.0/221.0	
Purchased electric, MW(e)	20.0	20.0	20.0	20.0[b]	
Salable electric, MW( )	0.0	0.0	0.0	408.0[c]	
Product output, MMB/yr					17.749
Process thermal efficiency, %					67
Capital costs					
Total direct costs	558.0		558.0	591.8	
Construction services & field eng.	139.5		111.6	118.4	
Total field costs	697.5		669.6	710.2	
Engineering services & fees	104.6		80.4	85.2	
Contingency	80.2		75.0	79.5	
Total plant investment	882.3		825.0	874.9	
Owner's cost	44.1		24.8	26.2	
Subtotal costs	926.4	280.0	849.8	901.1	1732.2
Escalation on total direct cost[d]	0.0	0.0	0.0	0.0	0.0
Subtotal escalated costs	926.4	280.0	849.8	901.1	1732.0
AFUDC[e]	127.7	12.3	138.2	146.6	147.2
Total capital requirement, 1983 MM$	1054.1	292.3	988.0	1047.7	1879.4
Annual cost (1983 MM$; 30-yr levelized)					
Fixed	89.6	24.6	84.0	89.1	257.5
Fuel - nuclear	38.3		38.3	35.9	
Fuel - oil/gas	62.1	86.4	62.1		
O&M process energy plant	42.5	4.7	62.5	1.0[f]	
O&M process plant		1.5			181.6
Electric power (credit)/debit	12.3		2.3	(85.1)	
Total annual cost, 1983 MM$	244.8	117.2	249.2	40.9	439.1
Cost of products, $/B (1983 $)	45.14		41.08		

[a] Standby/on line.

[b] Excess process electric bought from backup plant.

[c] Standby all electric.

[d] Escalation = subtotal costs compounded from project start to the centroid of the construction period.

[e] AFUDC = subtotal costs compounded from construction start to the centroid of the construction period.

[f] Twin plant O&M on base plant.

A review of Table 5-4 results shows that the HTGR-assisted direct steam retorting process with an HTGR backup has a lower product price ($41.08/B) than with an oil-fired plant backup ($45.14/B), since the latter has a higher fuel oil use and derives no electric power credit. A relative comparison with the product price of the indirect gas retorting process (Ref. 1-3) shown in Table 5-5 indicates that the HTGR-SC/C-assisted case (with an HTGR backup) is the nearest competitor ($42.36/B) to the corresponding case in the direct steam retorting process. The HTGR-PH, the HTGR-SC/C-assisted indirect retorting operation with oil backup, and the standard Paraho process all have considerably high product price,primarily because of high consumption of expensive fuel oil for primary or backup energy.

Table 5-6 shows an additional economic analysis for the HTGR-SC/C-assisted direct steam retorting process in which the amount of product oil and gas used as fuel is deducted from the gross product yield. In addition, a real escalation rate of 2% per year is applied to the shale mining costs as the seams in the mine become progressively thinner and increasingly difficult to mine. The combination of these two effects shows a product price of $47.70/B (1983 $, 30-yr levelized). This additional economic analysis is presented for illustration only.

REFERENCE

5-1. "EPRI Technical Assessment Guide," Electric Power Research Institute Report EPRI PS-1201-SR, July 1979.

TABLE 5-5
ECONOMIC ANALYSIS FOR A PARAHO LARGE COMMERCIAL 7,150 m^3/D (45,000 B/D) HYDROGENATED SHALE OIL PLANT WITH INDIRECT GAS RETORTING
NOTE: ALL $ IN 1983 CONSTANT $ UNLESS OTHERWISE NOTED

	Option One			Option Two		
	Primary	Backup		Primary	Backup	
	HTGR-PH (N^{th} Plant)	Oil Plant	Process Plant	HTGR-SC/C (N^{th} plant)	Oil Plant	Process Plant
Ownership	Utility	Utility	Industry	Utility	Utility	Industry
Plant parameters						
Feed shale, MMkg/h (T/D)			2.48 (65,600)			2.72 (71,900)
Thermal rating (input), MW(t)	1170.0	1427.0		1170.0	1427.1	
Heat input to the cycle, MW(t)	1170.0	1170.1		1170.0	1170.1	
Gross electric output, MW(e)	215.0	215.0		275.0	275.0	
Net electrical output, MW(e)	130.0	130.0		240.0	240.0	
Salable electric, MW(e)	0.0	0.0		83.0	83.0	
Product output, MMB/yr			15.359			15.491
Process thermal efficiency, %						59
Capital costs						
Total direct costs	763.7			550.7		
Construction services & field eng.	190.9			137.7		
Total field costs	954.6			688.4		
Engineering services & fees	143.2			103.3		
Contingency	219.6			79.2		
Total plant investment	1317.4			870.9		
Owner's cost	65.9			43.5		
Subtotal costs	1383.3	280.0	1375.2	914.4	280.0	1612.3
Escalation on total direct cost[a]	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal escalated costs	1383.3	280.0	1375.2	914.4	280.0	1612.3
AFUDC[b]	190.7	12.3	116.9	126.1	12.3	137.0
Total capital requirement, 1983 MM$	1574.0	292.3	1492.1	1040.5	292.3	1749.3
Annual cost (1983 MM$; 30-yr levelized)						
Fixed	133.8	24.6	204.4	88.4	24.6	239.7
Fuel - nuclear	43.6			38.3		
Fuel - oil/gas		108.0		61.8	86.4	
O&M energy plant	64.6	4.8		42.5	4.7	
O&M process plant			187.9			181.6
Electric power (credit)/debit	0.0	0.0		(32.7)	(4.1)	
Total annual cost, 1983 MM$	242.0	137.4	392.3	198.3	111.6	421.3
Cost of shale oil (upgraded), $/B (1983 $)			50.24			47.20

TABLE 5-5 (Continued)

	Option Three			Option Four	
	Primary	Backup		Standard	Paraho
	HTGR-SC/C (N^{th} Plant)	HTGR-SC/C (N^{th} Plant)	Process Plant	Energy Plant	Process Plant
Ownership	Utility	Utility	Industry	Utility	Industry
Plant parameters					
Feed shale, MMkg/h (T/D)			2.72 (71,900)		2.48 (65,600)
Thermal rating (input), MW(t)	1170.0	1170.0		1155.0	
Heat input to the cycle, MW(t)	1170.0	1170.0		947.0	
Gross electric output, MW(e)	275.0	464.0/275.0	(c)	137.0	
Net electrical output, MW(e)	240.0	428.0/240.0	(d)	137.0	
Salable electric, MW(e)	83.0	345.0/83.0	(d)	0.0	
Product output, MM B/yr			15.491		15.393
Process thermal efficiency, %			59		60
Capital cost					
Total direct costs	550.7	591.8			
Construction services & field eng.	110.1	118.4			
Total field costs	660.8	710.2			
Engineering services & fees	79.3	85.2			
Contingency	74.0	79.5			
Total plant investment	814.1	874.9			
Owner's cost	24.4	26.2			
Subtotal costs	838.5	901.1	1612.3	166.6	1508.8
Escalation on total direct cost[a]	0.0	0.0	0.0	0.0	0.0
Subtotal escalated costs	838.5	901.1	1612.3	166.6	1508.8
AFUDC[b]	136.4	146.6	137.0	7.3	128.2
Total capital requirement, 1983 MM$	974.9	1047.7	1749.3	173.9	1637.0
Annual cost (1983 MM$; 30-yr levelized)					
Fixed	82.9	89.1	239.7	14.6	224.3
Fuel - nuclear	38.3	35.9			
Fuel - oil/gas	61.8			349.9	
O&M energy plant	62.5	1.0		6.7	
O&M process plant			181.6		167.8
Electric power (credit)/debit	(32.7)	(103.9)		0.0	
Total annual cost, 1983 MM$	212.8	22.1	421.3	371.1	392.1
Cost of shale oil (upgraded), $/B (1983 $)			42.36		49.58

(a) Escalation = subtotal costs compounded from project start to the centroid of the construction period.

(b) AFUDC = subtotal costs compounded from construction start to the centroid of the construction period.

(c) Standby/on line.

(d) Non-firm/firm.

TABLE 5-6
ECONOMIC ANALYSIS FOR A COMMERCIAL 8,130 m^3/D (51,139 B/D)
NET HYDROGENERATED SHALE OIL PLANT WITH DIRECT STEAM RETORTING PROCESS

NOTE: ALL $ IN 1983 CONSTANT $ UNLESS OTHERWISE NOTED

	Option One		Option Two		
	Primary	Backup	Primary	Backup	
	HTGR-SC/C (Nth Plant)	Oil Plant	HTGR-SC/C (Nth Plant)	HTGR-SC/C (Nth Plant)	Process Plant
Ownership	Utility	Utility	Utility	Utility	Industry
Plant parameters					
Thermal rating (input), MW(t)	1170.0	1427.0	1170.0	1170.0	
Heat input to the cycle, MW(t)	1170.0	1170.1	1170.0	1170.0	
Gross electric output, MW(e)	256.0	256.0	256.0	464.0/256.0[a]	
Net electrical output, MW(e)	221.0	221.0	221.0	428.0/221.0[a]	
Purchased electric, MW(e)	20.0	20.0	20.0	20.0[b]	
Salable electric, MW(e)	0.0	0.0	0.0	408.0[c]	
Product output, MM B/yr					16.799
Capital Costs					
Total direct costs	558.0		558.0	591.8	
Construction services and field eng.	139.5		111.6	118.4	
Total field costs	697.5		669.6	710.2	
Engineering services and fees	104.6		80.4	85.2	
Contingency	80.2		75.0	79.5	
Total plant investment	682.3		825.0	874.9	
Owner's cost	44.1		24.8	26.2	
Subtotal costs	926.4	280.0	849.8	901.1	1732.2
Escalation on total direct costs[d]	0.0	0.0	0.0	0.0	0.0
Subtotal escalated costs	926.4	280.0	849.8	901.1	1732.2
AFUDC[e]	127.7	12.3	138.2	146.6	147.2
Total capital requirement, 1983 MM$	1054.1	292.3	988.0	1047.7	1579.4
Annual cost (1983 MM$, 30-yr levelized)					
Fixed	89.6	24.6	84.0	89.[illegible]	257.5
Fuel - nuclear	38.3		38.3	35.9	
Fuel - oil/gas					
O&M process plant	42.5	4.7	62.5	1.0[f]	181.6
Electric power (credit)/debit	12.3	1.5	2.3	(85.1)	135.0
Shale scarcity[g]					
Total annual cost, 1983 MM$	182.7	30.8	187.1	40.9	574.1
Cost of products, $/B (1983 $)		50.90		47.75	

[a] Standby/on line.
[b] Excess process electric bought from backup plant.
[c] Standby all electric.
[d] Escalation = subtotal costs compounded from project start to the centroid of the construction period.
[e] AFUDC = subtotal costs compounded from construction start to the centroid of the construction period.
[f] Twin plant O&M on base plant.
[g] Scarcity rate = 2%.

6. ENVIRONMENTAL AND WATER CONSIDERATIONS

6.1. ENVIRONMENT

Davy McKee has performed an in-depth environmental study of the Paraho shale oil recovery process in which all process heat is supplied by firing upgraded product oil (Ref. 1-3). Environmental data pertinent to the direct steam retorting process using an HTGR-SC/C plant, are presented in this section and compared with those of the indirect Paraho process. Environmental considerations primarily extend to four areas: (1) air, (2) water, (3) solid waste, and (4) thermal impact. Each of these areas is briefly discussed in the following subsections.

6.2. AIR

Atmospheric emissions will occur from several sources during oil shale processing. The major sources of sulfur dioxide (SO_2), nitrogen oxide (NO_x), and carbon monoxide (CO) will be fuel combustion for process heat, predominantly at the reforming furnace. Particulate matter emissions will occur from fuel combustion, raw and spent shale dust in process streams, raw and spent shale handling and disposal, mining and blasting, and other site activities that generate fugitive dust.

Pyrolysis of oil shale will produce polycyclic organic material (POM). POM compounds could be released to the atmosphere during shale retorting, disposal, and handling of retorted shales or during combustion of shale-derived oils. Gaseous ammonia (NH_3), hydrogen sulfide (H_2S), and volatile organics may be released during moisturizing and subsequent cooling of the retorted shale. Fugitive dust emissions are expected from spent shale handling and during catalyst regeneration, handling, and final disposal. The exact consequences of releasing the above contaminants into the atmosphere

are presently not known. However, it is likely that the emission of such pollutants can be held to acceptable levels through control technology.

Table 6-1 presents an overall emission summary for the direct steam retorting process, which uses an HTGR-SC/C plant as its energy source, with a backup HTGR-SC/C plant; Table 6-2 shows the emissions for the same case with an oil-fired plant backup. Table 6-3 shows a summary of air emissions from a standard Paraho retorting plant for comparison. The commercial oil shale plant is assumed to be located in an "attainment area," defined as an area where the ambient air quality is currently cleaner than defined in the National Ambient Air Quality Standards for SO_2, CO, total suspended particulates, photochemical oxidants (O_x), nitrogen dioxide (NO_2), or lead (Pb).

There are presently no federal emission standards specifically covering oil shale production. The State of Colorado, however, has enacted a few regulations directed to the shale oil industry on air emissions. One requires commercial operations [producing more than 6.7 m^3/h (1000 B/D)] to restrict themselves to 0.85 kg SO_2/m^3 (0.3 lb SO_2/B) of oil production plus an equal amount for the refining operation. Similarly, hydrogen sulfide emission is limited to 10 ppm based on a one-hour average ambient air concentration.

A review of Tables 6-1 and 6-3 shows a considerable reduction in pollutant emission from a direct steam retorting HTGR-SC/C plant as compared with a standard indirect Paraho retorting plant. This reduction occurs primarily because of a substantial reduction in the use of the product oil as fuel. The particulates and SO_2 emissions are reduced to approximately two-thirds of the standard plant emission, and the NO_x is reduced by 60%. Thus, the integration of an HTGR-SC/C plant as an energy source with the direct steam retorting process minimizes the overall plant effluents.

The HTGR-SC/C oil backup case showed only a marginal increase in pollutant emissions when compared with the twin HTGR-SC/C plant case.

TABLE 6-1
AIR EMISSION SUMMARY FOR A 2.65 x 10^6 kg/h (70,000 T/D)/8,590 m^3/D (54,030 B/D)
DIRECT STEAM PROCESS USING AN 1170-MW(t) HTGR-SC/C PLANT WITH
AN 1170-MW(t) VARIABLE COGENERATION HTGR BACKUP

	Particulates	SO_2	NO_x	HC	CO	CO_2	H_2S
Mining[a]	12 (624)		2 (87)		21 (1,100)		
Shale preparation[b]	16 (892)						
Retorting	10 (553)	15 (815)	114 (6,074)	5.0 (275)	26 (1,377)	0.1 x 10^6 (5.22 x 10^6)	4 (212)
Spent shale treatment and disposal	25 (1,308)						
Upgrading	0.3 (20)	0.6 (30)	5 (239)	0.25 (11)	1.0 (54)	4,616 (244/222)	
Ammonia and sulfur recovery				63 (3,284)	1,554 (82,260)		
Product storage				1.7 (87)			
Steam and power							
Hydrogen production	5 (234)	7 (345)	49 (2,569)	2 (117)	11 (584)		
Total[c]	68 (3,631)	22 (1,190)	170 (8,969)	72 (3,774)	1,613 (85,375)	0.2 x 10^6 (11.06 x 10^6)	

[a] Does not include mobile mine equipment.

[b] Does not include hauler emissions.

[c] It should be noted that emissions are regulated on a process basis and are not generally regulated as one large point source emission for the entire process area.

TABLE 6-2
AIR EMISSION SUMMARY FOR A 2.65 x 10^6 kg/h (70,000 T/D)/8,590 m^3/D (54,030 B/D) DIRECT STEAM PROCESS USING AN 1170-MW(t) HTGR-SC/C PLANT WITH AN OIL-FIRED BACKUP
[kg/h (lb/day)]

	Particulates	SO_2	NO_x	HC	CO	CO_2	H_2S
Mining[a]	12 (624)		2 (87)		21 (1,100)		
Shale preparation[b]	16 (892)						
Retorting	10 (553)	15 (815)	114 (6,074)	5.0 (275)	26 (1,377)	0.1 x 10^6 (5.22 x 10^6)	4 (212)
Spent shale treatment and disposal	25 (1,308)						
Upgrading	0.3 (20)	0.6 (30)	5 (239)	25 (11)	1.0 (54)	4,616 (244/222)	
Ammonia and sulfur recovery				63 (3,284)	1,554 (82,260)		
Product storage				1.7 (87)			
Steam and power	8 (404)	4 (187)	54 (2,870)	1.1 (58)	5.5 (288)	0.01 x 10^6 (1.21 x 10^6	
Hydrogen production	5 (234)	7 (345)	49 (2,569)	2 (117)	11 (584)	0.1 x 10^6 (5.6 x 10^6)	
Total[c]	76 (4,035)	30 (1,377)	224 (11,839)	73 (3,832)	1,619 (85,663)	0.22 x 10^6 (12.2 x 10^6)	

[a] Does not include mobile mine equipment.

[b] Does not include hauler emissions.

[c] It should be noted that emissions are regulated on a process basis and are not generally regulated as one large point source emission for the entire process area.

TABLE 6-3
AIR EMISSION SUMMARY FOR A 2.49 x 10^6 kg/h (66,000 T/D)/7,000 m^3/D (44,064 B/D)
STANDARD INDIRECT RECYCLE GAS (PARAHO) RETORTING PLANT
[kg/h (lb/day)]

	Particulates	SO_2	NO_x	HC	CO	CO_2	H_2S
Mining[a]	11 (584)		1.5 (79)		20 (1,045)		--
Shale preparation[b]	16 (835)						--
Retorting	10 (518)	14 (766)	106 (5,702)	5 (259)	24 (1,296)	0.1 x 10^6 (4.91 x 10^6)	--
Spent shale treatment and disposal	23 (1231)						--
Upgrading	0.3 (16)	0.4 (24)	3 (180)	0.15 (8)	0.7 (41)	3,426 (185,000)	--
Ammonia and sulfur recovery				50 (2,726)	1264 (68,275)		212
Product storage				1.3 (72)			--
Steam and power	37 (2,016)	17 (936)	266 (14,352)	5 (288)	26 (1,440)	0.11 x 10^6 (6.06 x 10^6)	--
Hydrogen production	5 (234)	6 (345)	48 (2,569)	2 (117)	11 (584)	0.1 x 10^6 (5.6 x 10^6)	--
Total[c]	102 (5,434)	38 (2,071)	424 (22,882)	64 (3,470)	1,346 (72,681)	0.3 x 10^6 (16.8 x 10^6)	--

[a] Does not include mobile mine equipment.

[b] Does not include hauler emissions.

[c] It should be noted that emissions are regulated on a process basis and are not generally regulated as one large point source emission for the entire process area.

6.3. WATER

There are four sources of water available in the shale oil fields of Colorado:

1. Surface water.
2. Mine water.
3. Well water.
4. Run-off water.

However, water availability from these sources is not abundant and is a major concern in developing the shale oil industry in Colorado. The shale oil fields are generally in arid areas; indeed, any large-scale commercial oil shale operation in Colorado may be limited by water availability. Wastewater streams resulting from surface retorting facilities are treated for reuse as well as for dust control, spent shale moisturization, and shale disposal on site.

Based on environmental considerations, contaminated wastewater streams from shale surface retorting facilities could have access to aquifers and ground water, resulting in fouling. Depending upon the pollutant, an effluent limitation may permit some level of pollutant discharge or may prohibit any discharge of the pollutant. The State of Colorado issues discharge or disposal permits for the sources of pollutants to ensure compliance with all effluent limitations and other requirements.

6.4. SOLID WASTE

Solid waste disposal from oil shale processing presents one of the major problems associated with commercial development of the oil shale industry. The predominant source of solid waste will be shale-derived, including spent shale, raw shale fines, and mined raw shale. No solid waste resulting from shale surface retorting facilities has yet been classified as hazardous by federal or state agencies.

6.5. THERMAL IMPACT

The thermal pollution of Colorado waters under the aquatic life classification is limited, generally, to a maximum 3°C (38°F) increase over a minimum of a four-hour period, lasting for 12 hours maximum. Recreational, agricultural, and domestic water classifications do not have express thermal limitations.

6.6. HTGR EFFLUENTS

The foregoing discussion on enviromental effluents pertains primarily to shale retorting and process side. Table 6-4 shows the environmental effluents (air emissions, solid wastes, and liquid effluents) from an 1170-MW(t) HTGR plant. They are within limits set by the Federal Nuclear Regulatory Administration.

TABLE 6-4
ENVIRONMENTAL EFFLUENTS FROM AN 1170-MW(t) HTGR PLANT

Air emissions	
Noble gases, Ci/yr	99[a]
Iodine and particulates, Ci/yr	0.01
Solid wastes	
Miscellaneous radioactive material, Ci/yr	7570[b]
Liquid effluents	
Mixed fission products (no tritium), Ci/yr	0.0021

[a] Includes 0.09 Ci/yr of tritium.

[b] Includes tritium contained in solidified high-specific-activity liquids.

7. CONCLUSIONS

The direct steam shale surface retorting process integrating an 1170-MW(t) HTGR-SC/C plant has several advantages over the standard indirect retorting process, which uses about one-third of the product oil as fuel. It also compares favorably with the indirect Paraho process that integrates an HTGR-SC/C plant (Ref. 1-1) and an HTGR-PH plant as described in the Davy McKee study (Ref. 1-3). However, the direct steam retorting process, thus far, has been backed up only by laboratory experiments. Large bench scale testing has yet to be completed, and only Marathon, the only active developer of this process, has conducted preliminary bench scale work. Because of the proprietary nature of the work, Marathon has not released any significant interim results and/or information leading to a commercial development. Therefore, the conclusions stated herein are based on the assumption that the commercial plant operation will be reasonably close to the laboratory experiments, without a significant loss of performance due to the expansion of scale.

Major conclusions of the present study are:

1. A survey of various surface retorting processes developed thus far by the shale industry shows that the direct steam retorting process has higher Fischer Assay values (higher oil yield) for a combination of several temperature and pressure parameters of the retorting medium used in other processes.

2. The H_2 content of the off-gases from the direct steam retorting process (50% by volume, acid-free basis) is higher than that obtained in other known processes. The higher H_2 content not only reduces the feed gas supply to the reforming (H_2) plant and increases the product fuel gas yield, but also enhances the gas higher heating value [34 MJ/m^3 (895 Btu/SCF) is predicted].

3. The HTGR-SC/C is an available technology that can be integrated as the source of energy with the direct steam retorting process.

4. The HTGR-SC/C plant as an energy source conserves considerable amounts of product oil (nearly a third of the gross product yield) that would otherwise be burned to provide the necessary energy.

5. The HTGR-SC/C plant reduces the environmental emissions significantly in comparison with the standard oil-burning process.

6. One 1170-MW(t) HTGR-SC/C plant with a 1170-HTGR-SC/C backup can supply approximately 69% of the process thermal energy and all of the on-site electrical power requirements except during a brief 10% process plant operation time when a 20-MW(e) electric power deficit is secured from other sources. However, during 65% of the process plant operation, a surplus 408 MW(e) electric power is cogenerated for export; this affords a substantial revenue credit.

7. Preliminary economic analysis favors the direct steam/HTGR-SC/C process over the standard indirect process on the basis of product price (ratio 1.00:1.21).

8. The critical equipment item in the direct steam retorting process is the economizer/condenser unit. This component condenses steam trapped in a multicomponent (steam, oil, gas) mixture at a relatively low pressure (slightly above atmospheric pressure). The impact of steam partial pressure and mass transfer variation during condensation is a major design consideration. The performance of such a component for a large commercial plant operation holds the key for the success of the process.

END OF PAPER