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SUMMARY
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1170-MW(t) HTGR-PS/C PLANT APPLICATION STUDY REPORT: SHALE OIL RECOVERY APPLICATION

by
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DISCLAIMER

INTRODUCTION

The U.S. has large shale oil energy resources, and many companies have undertaken considerable effort to develop economical means to extract this oil within environmental constraints. The recoverable shale oil reserves in the U.S. amount to 160 x 10^9 m^3 (1000 x 10^9 bbl) and are second in quantity only to coal. This report summarizes a study to apply an 1170-MW(t) high-temperature gas-cooled reactor - process steam/cogeneration (HTGR-PS/C) to a shale oil recovery process. Since the highest potential shale oil reserves lie in the Piceance Basin of Western Colorado, the study centers on exploiting shale oil in this region.

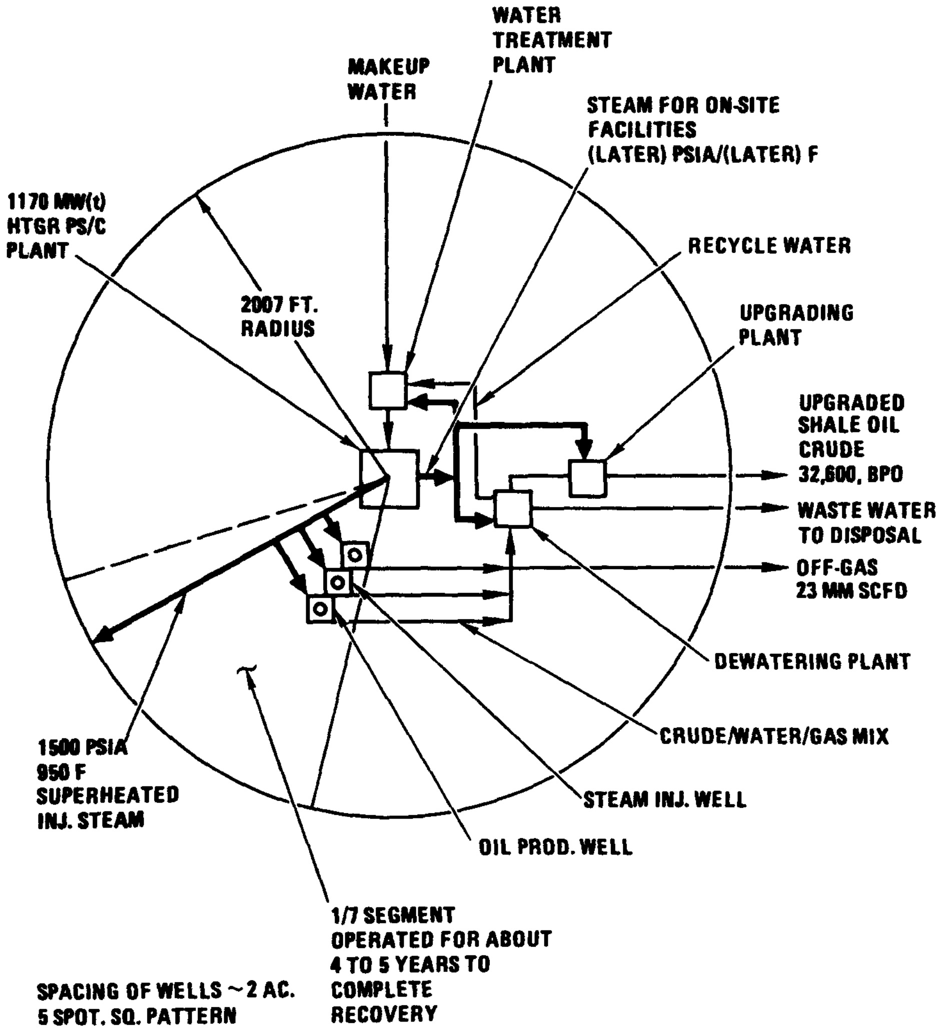
Shale is typically covered by an overburden that makes open pit mining uneconomical. The shale must be retorted to extract combustible fluids; the retorting is done at the mine site, because transporting the shale elsewhere is uneconomical. Above-ground retorting presents several disadvantages, such as large volumes of tailings (larger than the mined volumes due to expansion after retorting) that have to be revegetated, considerable power requirements for extraction and crushing, and severe environmental limitation to prevent atmospheric pollution and contamination to aquifers. These disadvantages all require large amounts of water, not available in arid Western Colorado. In fact, according to an Environmental Protection Agency sponsored study, the Piceance basin production will be limited to 63,560 to 95,340 m^3/day (400,000 to 600,000 bpd) by water availability if above-ground retorting is adopted.

In-situ retorting is one alternative being investigated. In this approach, shale is fractured underground by blasting, then retorted with air (by igniting the shale underground and flowing air to the fire) or with steam injected at sufficient temperatures [427° to 538°C (800° to 1000°F)] to extract the combustible fluids. Controlling underground combustion, ensuring complete collection of valuable combustion products, and preventing aquifer contamination are difficult with air retorting. Steam retorting allows better emission control and improves the quality of the shale oil produced. It is particularly appropriate for shales that have a natural porosity. The recovery pattern is similar to that of in-situ heavy oil recovery with steam.

Shale oil extraction processes are still being investigated. Accordingly, this study is necessarily preliminary. It is based on in-situ steam retorting, which appears to be potentially attractive. The HTGR is highly suitable as a steam source for this process, while light water reactors (LWRs) are unsuitable, because they produce steam at temperatures too low for shale retorting.

APPLICATION REQUIREMENTS

This study is based on the Equity Oil Company in-situ steam retorting project, located in Piceance Basin shale fields having a good natural porosity. A pilot plant is being operated within these fields, injecting steam at 10.34 MPa (1500 psia) and 538°C (1000°F). For the HTGR application, a five-spot, 0.8-m^2 (2-acre) square pattern of oil recovery wells is proposed with a centrally located steam injection well (see Fig. 1). Steam is to be injected continuously at 17.0 kg/s (1.25 x 10^5 lb/hr) through each injection well. The steam is injected over the 16.2-m^2 (40-acre) area, and an oil liberation of 5182 m^3/day (32,600 bpd) is expected. This yield represents ~50% of the in-place reserve. Since the Piceance Basin is a remote area, the reactor can be located relatively close to the well heads, and pressure drops and steam losses in the steam lines are expected to be modest. No reboiler has been included to isolate the injected steam from the secondary coolant loop of the reactor. A reboiler may be included, if deemed necessary, but it would modestly reduce performance, primarily reducing output of cogenerated electrical power.



IN-SITU PROCESS – STEAM DRIVE			
OPERATION PRODUCTION AREA	0.16×10^6 M^2 (40 Ac)		
TOTAL PRODUCTION AREA	1.15×10^6 M^2 (285 Ac)		
STEAM REQUIREMENTS	KG/S	LB/HR	B/D
INJECTION WELLS @ 1500 PSIA/950 F	338	2.7×10^6	18.4×10^4
ON-SITE UPGRADING		LATER	
WATER TREAMENT		LATER	
DEWATERING		LATER	
SHALE OIL RECOVERY			
FROM TOTAL PRODUCTION AREA	5087×10^6 LTRS (320×10^6 BARRELS)		
OFF-GAS EQUIVALENT THERMAL ENERGY	42 MWt		
RECOVERY OF RESOURCES IN PLACE	~50%		

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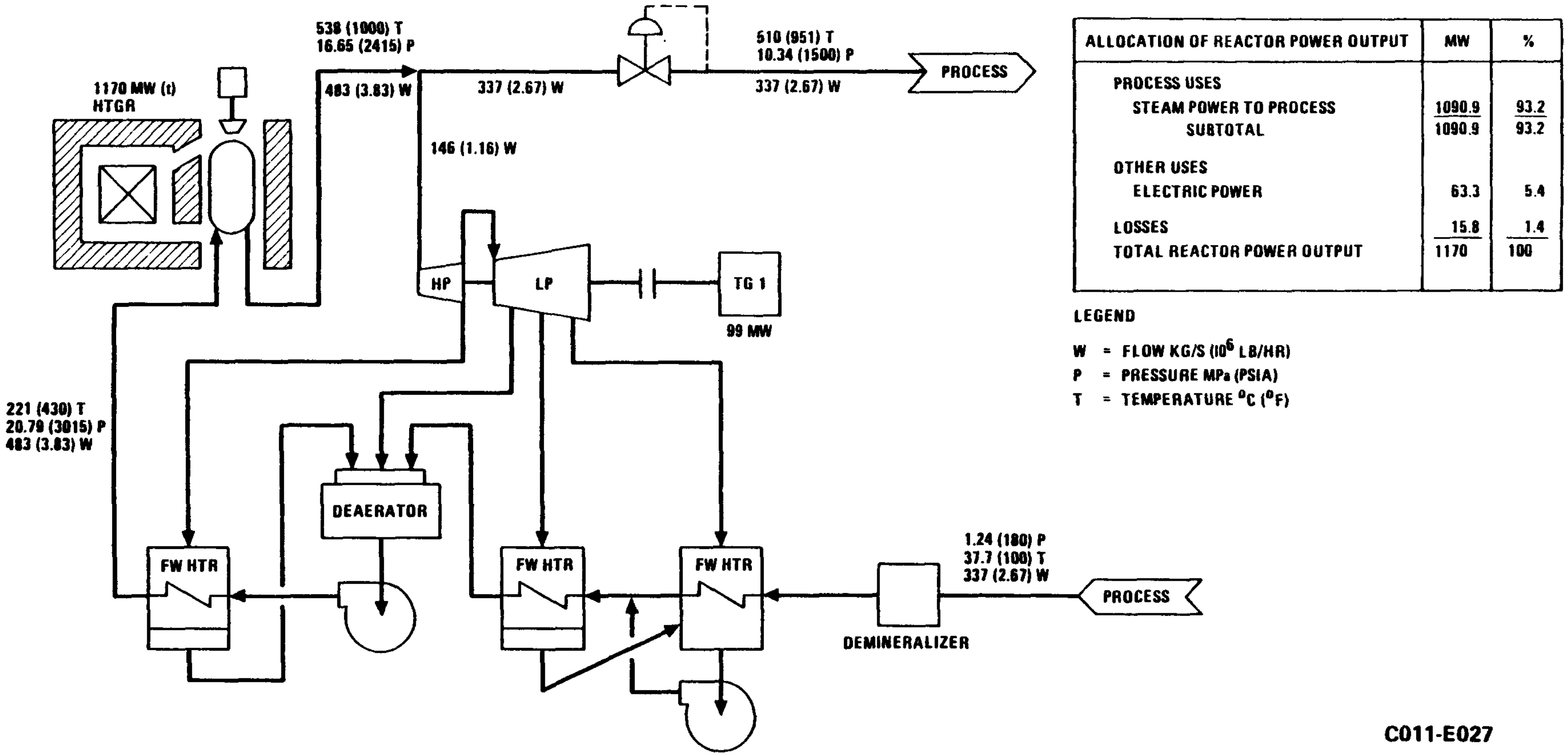
Fig. 1. Field arrangement for 5173 m^3 (32,600 barrel) per stream day oil shale recovery application using an 1170-MW(t) HTGR-PS/C

The selected heat cycle (see Fig. 2) is designed to produce as much steam as possible to recover shale oil. No specific electric power requirements are established for the recovery process at this time, but they are assumed to be small in the absence of any immediate product upgrading plant. Only enough steam to provide extraction steam for feedwater heating is supplied to the turbine generator. The feedwater train includes three heaters plus a deaerating heater. The turbine is a noncondensing unit expanding from 16.65 MPa (2415 psia) to 58 kPa (8.42 psia), similar to the high-pressure and intermediate-pressure units of a small conventional turbine generator. The turbine flow is 146 kg/s (1.16×10^6 lb/hr), while the steam flow generated by the 1170-MW(t) HTGR-PS/C is 483 kg/s (3.83×10^6 lb/hr); the remaining 337 kg/s (2.67×10^6 lb/hr), representing an output of 1091 MW, are used for injection, after throttling down to the injection pressure of 10.34 MPa (1500 psia). The steam temperatures are 538°C (1000°F) at the HTGR outlet and about 510°C (915°F) at the injection wells. The return flow of condensate and makeup from the shale oil recovery process is assumed to be at 124 kPa (180 psia) and 38°C (100°F). This flow is passed through a full flow demineralizer. The electrical generator output is 99.3 MW(e), while the net output is 63.3 MW(e). The difference is used to drive the HTGR circulators, the feedpumps, and other nonprocess auxiliaries.

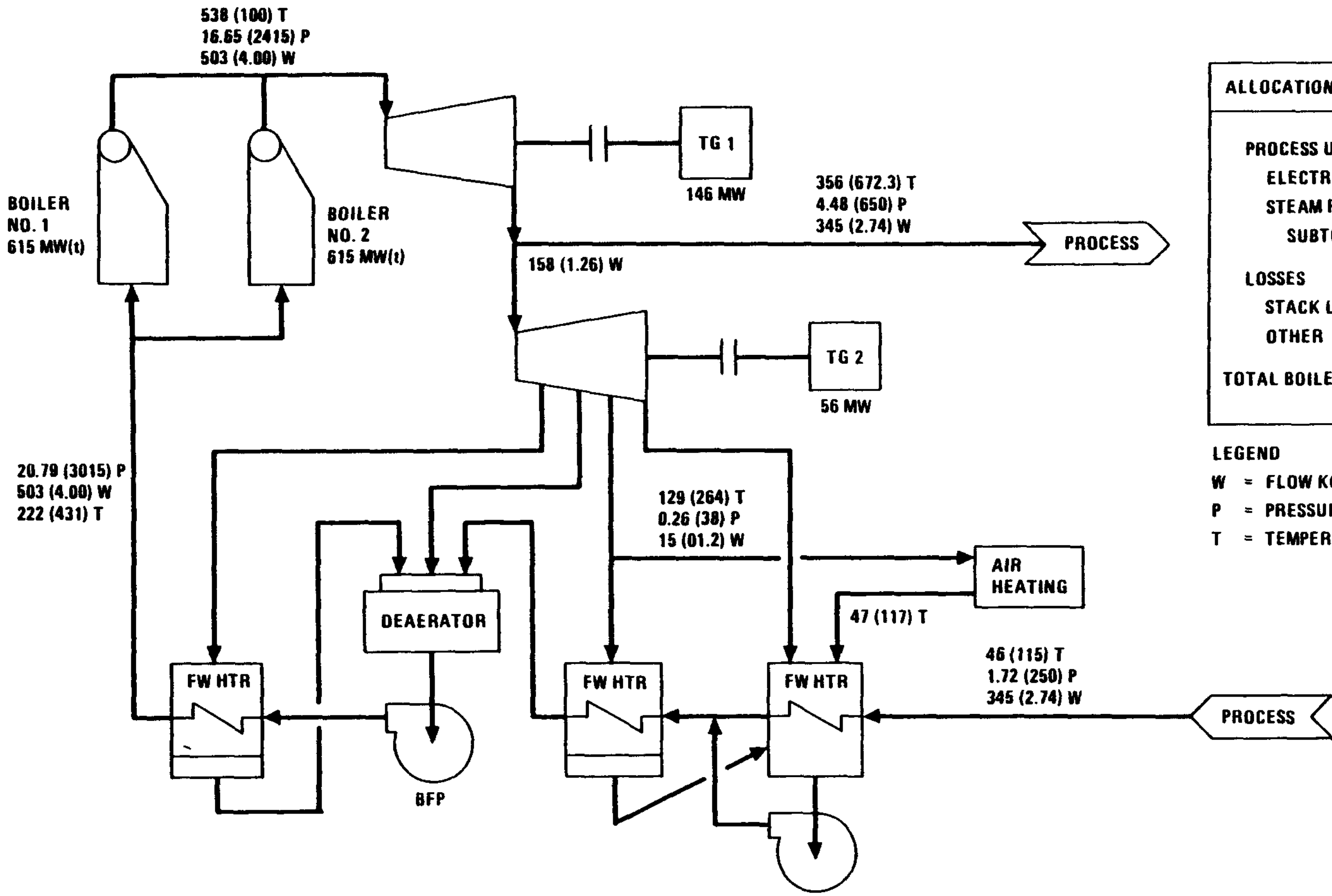
A coal-fired cycle, having a steam output of the same magnitude as the 1170-MW(t) HTGR, was studied for comparison. As indicated by Fig. 3, this cycle is very similar to the previous one, except for the heat source. The coal-fired plant delivers the same supply of steam to the shale oil field, but it requires a higher overall thermal rating [1230.2 instead of 1170 MW(t)] and produces more electric power [69.5 instead of 63.3 MW(e)].

Oil shale processes, as presently formulated, provide most of their own energy requirement through an intermediate product, a low-caloric combustible off-gas. To make the HTGR application attractive, the process should be modified to utilize this off-gas economically. Upgrading the gas to make it marketable appears difficult considering the large shipping distances involved. An attractive alternate could involve upgrading the shale oil to



ALLOCATION OF REACTOR POWER OUTPUT	MW	%
PROCESS USES		
STEAM POWER TO PROCESS	1090.9	93.2
SUBTOTAL	1090.9	93.2
OTHER USES		
ELECTRIC POWER	63.3	5.4
LOSSES	15.8	1.4
TOTAL REACTOR POWER OUTPUT	1170	100

Fig. 2. Cycle diagram for an 1170-MW(t) HTGR-PS/C plant for 5173 m^3 (32,600 barrel) per stream day oil shale recovery application



ALLOCATION OF REACTOR POWER OUTPUT	MW	%
PROCESS USES		
ELECTRIC POWER	157.5	11.5
STEAM POWER TO PROCESS	1000.4	73.2
SUBTOTAL	1157.9	84.7
LOSSES		
STACK LOSSES	130.0	10.0
OTHER	72.1	5.3
TOTAL BOILER HEAT INPUT	1366	100

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

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Fig. 3. Cycle diagram for a coal-fired PS/C plant for multipurpose applications

reduce its waxiness, improve its viscosity and pour point, and make it suitable for feeding to conventional refineries presently using light crude as feedstock. A further merit of the latter approach is that the combustible off-gases may be a backup energy supply for the injection steam generator so that shale oil recovery and upgrading may continue when the reactor is shut down for maintenance and repairs, including refueling.

ECONOMIC ANALYSIS

The revenue requirement method was selected to evaluate alternative projects. This technique is appropriate for evaluating long-lived coal and nuclear cogeneration power plant projects. It determines the revenue needed by the firm as compensation for all fixed and variable expenditures. Hence, the revenue requirements of the firm equal the consumer cost for the process steam cogenerated.

Table 1 compares estimated energy costs of the 1170-MW(t) HTGR-PS/C versus the comparable coal-fired PS/C plant for shale oil recovery. It shows a clear advantage (28% less cost to deliver energy) of the HTGR over a coal-fired plant.

This analysis is based on economic assumptions used to evaluate utility cogeneration projects in progress for the Department of Energy (DOE) by GA in coordination with Gas Cooled Reactor Association (GCRA). Table 2 gives the principal assumptions of the economic analysis, a key one being the 18% fixed charge rate for capital use/recovery. Such a rate may be higher if industrial ownership ground rules are applied. Therefore, the economics should be determined using the economic ground rules appropriate for the specific application. Industrial user input is being developed regarding possible alternative economic ground rules.

TABLE 1
ECONOMIC ANALYSIS OF HTGR-PS/C PLANT VERSUS
COAL-FIRED PS/C PLANT FOR SHALE OIL RECOVERY APPLICATION

	HTGR-PS/C Plant	Coal-Fired Plant
Heat input to cycle (MW)	1170.0	1230.2
Heat output in process steam (MW)	1090.9	1090.9
Net electrical power output (MW)	63.3	69.5
Capital Costs ($\$ \times 10^6$)		
Base capital cost (1/80 $)	536	358
Escalation through construction	535	405
Interest during construction	336	152
Total capital cost (1/95 $)	1407	915
Annual Costs ($\$ \times 10^6$/year)[a]		
Fixed charges	253	165
Fuel costs	81	229
O&M costs	63	69
Credit for electric power	(66)	(72)
Total annual costs	331	461
Process Steam Cost [mills/kW(t)-hr ($/MMBtu)]	49.5 (14.51)	68.8 (20.18)
Ratio of Energy Cost to Cost with HTGR-PS/C	--	1.4

[a] 1/95 $ levelized over a 30-year period.

TABLE 2
ECONOMIC ANALYSIS ASSUMPTIONS

Commercial operation of all plants:	1/1/95
Capacity factor:	70%
Levelizing period:	30 years
Electric power credit:	22 mills/kW-hr (80 $)
Discount rate:	10%/year
Fixed charge rate:	18%/year
Interest during construction:	10%/year (simple interest)
Coal cost escalation:	8%/year
Fuel oil escalation:	9%/year
All other escalation:	6%/year
Construction period:	6 years for all plants (2 years for No. 6 oil-fired plants)
U_3O_8 (yellowcake) cost:	\$121/kg (\$55/lb) in 1990, rising to \$264/kg (\$120/lb) in 2030
Separative work unit (SWU) cost:	\$100/kg-SWU (80 $)
Tails assay:	0.2%
Coal cost:	4.64 mills/kW-hr (\$1.36/MMBtu) (80 $)
No. 2 oil cost:	18.2 mills/kW-hr (\$5.33/MMBtu) (80 $)
No. 6 oil cost:	13.5 mills/kW-hr (\$3.95/MMBtu) (80 $)
HTGR-PS/C fuel cycle cost (includes recycle):	11.23 mills/kW-hr (\$3.29/MMBtu) (1/95 $ levelized over 30 years)

Ultimately, the economic analysis method will be determined by the nuclear cogeneration plant ownership:

1. Industrial ownership with connection to the utility grid for backup electric power and sale of excess power (per recent Federal Energy Regulatory Commission rulings regarding a more favorable arrangement for industry).

2. Utility ownership with both steam and cogenerated electric power sold to nearby industry.

3. Consortia ownership and sale of energy to industry and local utilities.

The analysis compares the cost of process steam produced by the HTGR-PS/C with that produced by a coal-fired cogenerating plant and with the cost of burning No. 2 oil in existing equipment. It includes a credit for the electric power produced by the HTGR and coal-fired cogenerating plants. The analysis indicates a clear advantage for the HTGR over the coal and oil alternatives.

The assumed fuel cost for coal will also vary according to site location and other factors (i.e., Eastern versus Western coal, mine-mouth locations, etc.).

The most competitive oil shale application for the HTGR-PS/C is through an in-situ injection of high-pressure, high-temperature steam for shales with high permeability. These shales represent ~8% to 10% of the total resource in the Piceance Basin of Colorado. Assuming that up to half of the foreseen 63,560 m^3/day (400,000 bpd) potential could be captured by the HTGR and considering that each 1170-MW(t) HTGR can provide steam for ~5164 m^3/day (~32,500 bpd), a market exists for about six such HTGR units in this area of Western Colorado. The market might be enlarged by applying the HTGR to oil shales in other locations. However, depending upon shale recovery as an important vehicle for developing the HTGR-PS/C is risky. The optimum recovery process is simply not well enough defined. The alternatives of in-situ or open-air operation and steam or combustion retorting remain to be resolved. Further, since economics and regulatory restrictions are uncertain, the commercialization of shale oil recovery is not assured. Thus, a significant application development risk remains.