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MASTER

A UTILITY ASSESSMENT

THE MARKET FOR THE HTGR

AND

THE INCENTIVES FOR ITS UTILIZATION

Performed by

GAS-COOLED REACTOR ASSOCIATES
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A UTILITY ASSESSMENT: THE MARKET FOR THE HIGH TEMPERATURE GAS-COOLED REACTOR AND THE INCENTIVES FOR ITS UTILIZATION

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FOREWORD

Gas-Cooled Reactor Associates (GCRA) is a utility/user organization which has been established through the combined efforts of concerned utility and industry executives and government officials who believe that the United States should have the High Temperature Gas-Cooled Reactor (HTGR) as a commercially available option. This belief is based on gaining access to the high temperature capabilities of the HTGR which are unique relative to other current and envisioned nuclear systems. In addition, the HTGR systems provide inherent advantages associated with the current concerns of safety and licensing, siting, operation and maintenance, and fuel cycle efficiency and flexibility.

The GCRA role is responsive to the institutional issue of front-end participation in technology development by the end-user of the technology. This role ensures that the investment of government and private sector resources will result in an HTGR system that will favorably impact the U.S. energy economy. The specific role of GCRA is to:

- Represent utility/user interests in establishing Program objectives and the strategy to achieve such objectives.
- Conduct Program/Project evaluations to assess the costs, risks, and benefits of HTGR deployment.
- Conduct Program/Project integration to guide design and development activities to assure their relevance to utility/user interests and requirements.
- Serve as a surrogate utility/user through the Lead Project definition and conceptual design phase. Major activities include:
  - Manage the architect/engineer for balance-of-plant design.
  - Interface with the Nuclear Regulatory Commission for pre-application review program.
- Establish and coordinate utility/user funded support and ensure that maximum benefit and the most efficient utilization of resources is realized.
- Interface with utilities/users in other countries in support of overall international cooperation in the HTGR Program.

This document is the result of GCRA staff efforts in fulfilling the above role, particularly that of Program/Project evaluation.

Executive Summary

Primary purpose of this document: Identify and quantify the market potential of the various HTGR systems

The potential market: The electric utility industry will be the primary owner/operator of commercial HTGRs

Utility market factors are used as a basis for evaluation

A Utility Assessment: The Market for the HTGR and the Incentives for Its Utilization is a document which presents a technical, economic, and market assessment of the HTGR based on a utility-oriented analysis. This approach has been taken on the basis that the electric utility industry will be the primary owner/operator of commercial HTGRs in the foreseeable future. Therefore, the assessment of the HTGR must be based on the factors which utilities consider when they make a capital expenditure decision. These factors are discussed in Section 2.1, and each HTGR system is evaluated against them in Sections 5.3, 6.3, and 7.3. It is noted that the front-end design and development costs for the various HTGR systems have not been included in this Assessment.

1.0 Introduction

Private investment and utility participation are distinguishing characteristics of the HTGR Program

Section 1.0 provides a brief history of HTGR development and describes the evolution of the current program. Throughout the history of HTGR development, two characteristics have distinguished the HTGR Program from other advanced nuclear technologies. First, the HTGR represents the only advanced nuclear technology in which private investment has substantially exceeded federal support. Secondly, the HTGR has had continuing utility participation over its developmental history.

Peach Bottom accrued an outstanding record of performance

Major achievements in the HTGR Program to date include design, construction, and operation of the Peach Bottom and Fort. St. Vrain generating stations. The Peach Bottom reactor was completed in 1967 and was operated for a period of 7-1/2 years before decommissioning. The unit compiled an outstanding record of performance, including an average nuclear steam system availability of 88%.

Despite difficulties, Fort St. Vrain represents a major and successful advancement of HTGR technology

Despite well-publicized difficulties, the Fort St. Vrain reactor represents a major and successful advancement of HTGR technology. It has successfully operated up to

70% power and has demonstrated the HTGR's excellent fuel performance and low radiation exposure to plant personnel. It has also demonstrated the HTGR's high temperature capabilities by achieving 1400°F primary loop and 1000°F steam temperatures.

The HTGR Program in the Federal Republic of Germany includes an HTGR steam cycle demonstration unit under construction

The THTR project in the Federal Republic of Germany is under construction and targeted for a 1983 startup. It is a 300 MWe demonstration steam cycle plant which uses spherical fuel elements. A follow-on to the THTR is being considered which would utilize HTGR steam cycle technology in a plant which would cogenerate electricity and steam for the hydrogasification of coal.

The central issue is to establish Program definition leading to a Lead Project

The central issue is to establish Program definition leading to a Lead Project that will be supported by all Program participants. The four Lead Project options that have received primary attention to date are:

- Gas Turbine (HTGR-GT)
- Steam Cycle (HTGR-SC) and its Process Steam/Cogeneration version (HTGR-PS/C)
- Reformer (HTGR-R)
- Nuclear Heat Source Demonstration Reactor (NHSDR)

These are described in more detail in Reference 1. This document will examine the market aspects of the commercial version of the first three options.

2.0 Market Projections

Section 2.0 identifies and describes the utility market factors. It also projects total energy demand for both electricity and process heat which the HTGR would be able to supply.

Generic market factors identified

When a utility makes a decision to purchase a particular type of generation facility, it considers several generic factors regardless of the type of generation being considered and evaluates the alternative choices with regard to these factors:

- Forecasted Energy Demand
- Siting Flexibility
- Technology Development Status
- Regulation and Licensing
- Commercial Status
- Plant Capabilities
- Economics

Specific nuclear market factors identified

There are several factors which affect primarily the nuclear power generation market that must be considered when comparing two competing nuclear technologies. These factors are:

- Capital Risk
- Safety
- Personnel Radiation Exposure
- Fuel Cycle Flexibility
- Advanced Applications

This document will examine each of the HTGR systems via these market factors against their anticipated competition. The weighting of each of these factors relative to the others is a subjective process which is left to the reader.

Energy demand forecasts indicate substantial potential market sizes for both electricity production and distributed industrial process heat

In order to establish the maximum size of the potential market for the HTGR, the demand for both electricity and process heat in the 2000-2020 time frame was forecast. For electricity, it is expected that approximately 850 GWe of central station generating capacity will be built between 2000 and 2020. Of this, the nuclear portion of the market is expected to be approximately 430 GWe.

The industrial and synfuels process heat market forecasts are shown below:

Industrial (GWt)	2000	2020
<500°F	550	1130
500-1000°F	417	854
>1000°F	267	508
	1234	2492

Synfuels (GWt)	2000	2020
Coal Gas	5	20
Liquid		
- Coal	16	122
- Shale	20	50
	41	192

The HTGR offers the potential to serve these distributed process heat and synfuels markets using the HTGR-PS/C version of the HTGR-SC. Additional potential is offered by more advanced versions incorporating enhanced energy distribution and storage concepts. One configuration employing thermochemical energy storage via the HTGR-R and thermochemical pipeline (TCP) concepts has been recently studied. A second configuration employing a sensible heat medium (molten salt) for energy storage and distribution will be further investigated in the near term. A survey of existing industrial facilities indicates that approximately 99% of all plants require 20 MWt or less of fossil-fired process heat, with 85% requiring less than 1 MWt. Also, approximately 82% of all facilities operate for only one shift, six days/week, while only 2% operate more than 2 shifts, seven days/week. At present, however, there are approximately 1850 plants which require more than 50 MWt, and more than 80% of these operate more than one shift/day. This indicates that:

The profile of the distributed industrial process heat market indicates the need for an energy storage system in many areas to maintain a high capacity factor of the central station

- A large distribution network may be needed to serve many small industries from a single central station facility.

- A market does exist for serving large industrial plants which have relatively high capacity factors.

- Some type of energy storage system will be required in order to match the small distributed process heat market to the single large central station facility in order to maintain a high capacity factor for the central facility.

3.0 Utility Systems Analysis

In this section, the market penetrability of the HTGR is assessed from the perspective of the electric utility industry by using systems methodology and generation planning techniques. It was hoped to gain insight into the areas of HTGR design and performance which will yield demonstrable benefits to the utility/user.

An EPRI synthetic utility system was utilized with an optimized generation planning code to assess various parameters of the HTGR

An EPRI model of a synthesized northeastern utility system was used in conjunction with an optimized system generation code from General Electric Company by GCRA to perform economic and performance analyses on the effects of the HTGR on a typical utility system. Various parameters were varied for the HTGR, and the effects of these variations on the utility system economics were analyzed. Three base cases were run in order to get baseline data against which comparisons could be made (coal, LWR, HTGR).

Sensitivities of various parameters were compared to the base case results

Sensitivities of the system economics to changes in various parameters were analyzed. The parameters that were varied include:

- Capital Cost
- Fuel Cost
- O&M Costs
- Forced Outage Rates
- Planned Outage Rates
- Unit Size
- Load Growth Rates

Changes in capital cost of the HTGR will have the most significant effect on utility system economics

Changes in HTGR capital cost have the most significant effect on the utility system, followed in order by fuel costs, O&M, forced outage rate, and planned outage rate. Based on this analysis, it appears that future design work should concentrate on keeping the capital cost of the HTGR as low as possible. It also can be stated that as the capital cost of the HTGR rises above parity with the LWR, the systems savings produced by the fuel cost advantage disappears after a 5% capital cost increase.

Energy storage systems will have a significant impact on the utility system performance and economics

The three base cases were re-analyzed under the assumption that energy storage (batteries) would not be available during the study period. The results indicate that energy storage systems have their largest impact in systems which are dominated by capital-intensive but inexpensive-to-operate plants, i.e., nuclear. As the fuel costs for these plants decrease, the savings associated with energy storage increases. The energy storage systems displaced both peaking and intermediate duty capacity as they were added to the system.

The integration of the HTGR and energy storage systems is deserving of future analysis

Based on the results of the energy storage analysis and the inherent capabilities of the HTGR to utilize energy storage in the form of either sensible heat or thermochemical energy storage, future studies will concentrate on better defining the economic incentives for this type of operation.

4.0 HTGR Benefits Assessment

Section 4.0 examines the benefits of the HTGR by utilizing recent studies which have been performed to assess the features of the HTGR.

4.1 Safety and Licensing

HTGR inherent safety stems from core materials and the helium primary coolant

The HTGR core is constructed of graphite and ceramic materials. These materials maintain their integrity at temperatures well above normal operating conditions. The core also has a low power density and a strong negative temperature coefficient. The helium coolant is inert and does not react with the reactor internals.

The HTGR exhibits slow reaction to operational transients

In the event of loss of core cooling, the graphite acts as a heat sink. Interruptions of core cooling of approximately 30 minutes can be tolerated without any damage to primary system components, while approximately three hours is available to restore cooling before fuel damage or radioactivity release occurs.

Probabilistic risk assessment of the HTGR confirms its inherent safety features

General Atomic Company performed an Accident Inititation and Progression Analysis using probabilistic risk assessment techniques which studied a wide spectrum of accident sequences. This study received peer review from the NRC, ORNL, Brookhaven, and scientists in the FRG. The summary results show that the HTGR compares quite favorably with the LWR results obtained in WASH-1400.

Several licensing issues generic to all HTGRs remain to be resolved; none are expected to cause significant licensing delays

As part of the NASAP study, NRC reviewed oustanding HTGR licensing issues which remain to be resolved. The major categories of these issues are:

- Use of graphite as a structural material
- Core seismic response
- Fuel behavior
- Primary system integrity
- Emergency core cooling provisions
- Anticipated Transient Without Scram (ATWS)
- In-service inspection and testing

The concerns associated with these licensing topics generally stem from lack of experimental data to confirm licensing positions. As the HTGR Program progresses, these data will become available; therefore, these issues are not expected to cause lengthy licensing delays.

The HTGR-GT has unique licensing issues which have made it unsuitable as the HTGR Lead Project

The HTGR-GT has several unique licensing issues because of the higher core outlet temperatures, the higher primary coolant flow rates, and the presence of rotating turbomachinery within the PCRV. Significant safety and licensing concerns include:

- Shaft seal failure
- Internal pressure equilibration accident
- Turbomachine missiles
- Reactor internal acoustics

The resolution of these licensing concerns will require an expensive and lengthy program. These issues have effectively removed the HTGR-GT from consideration as the HTGR Lead Project.

The HTGR-R also offers unique licensing issues which have only recently been identified

The HTGR-R also has unique licensing issues associated with the reformer gas components. These include:

- Toxicity of the carbon monoxide
- Detonation capability of the methane and hydrogen
- Minimum safe distances between the reactor containment and the gas storage caverns and the reformers
- Tritium diffusion into the reformed gases with resultant transmission off-site

Little work has been done to date toward resolution of the above issues. They appear to offer significant problems to be addressed in future licensing activities and safety research.

4.2 Water Utilization

A significant market for dry and/or dry/wet cooling of power plants will exist after 2000

A study performed by the Hanford Engineering Development Laboratory (HEDL) for GCRA projected water use, water supply, electricity demand, and capacity requirements by Water Resource Council Aggregated

Sub-Areas (ASA) for the U.S. between 2000 and 2020. The results indicate that a total of between 178 and 483 GWe of electrical capacity to be installed in that time frame will require some form of dry-cooling technology. The location and types of capacity that would require dry-cooling technology were also projected.

An economic evaluation was performed comparing the HTGR-GT with an LWR and a coal-fired plant to quantify the economic incentive for the HTGR-GT with dry and/or dry/wet cooling

Based on the HEDL finding that the cost of water to the utility would not increase as it became scarcer but that the amount allocated to power plant consumption would be decreased, United Engineers & Constructors performed an economic analysis for GCRA which studied the HTGR-GT, LWR, and coal plants with imposed water consumption constraints. Each plant was studied at a common typical arid site, and its cooling system was optimized for several varied water consumption constraints. The cost of the cooling system and its associated operational penalties were calculated as a Total Evaluated (Cooling System) Cost (TEC).

The study results confirm that the HTGR-GT does utilize dry and dry/wet cooling more efficiently and with operational penalties of less magnitude than the LWR and the coal-fired units

The study calculated the TEC for each optimized cooling system. The trend of TEC vs. water consumption was constructed for each plant. When the results are compared, the HTGR consistently has the lower TEC when dry or dry/wet cooling is required. The magnitude of the HTGR-GT advantage is a function of water availability, i.e., the less water available, the greater the TEC advantage of the HTGR-GT. The effect of these findings on total plant economics is presented in Section 6.2.

4.3 Other Siting Considerations

The HTGR has a technical basis for greater flexibility in siting than the LWR from the standpoint of radiological impact

Studies have been performed which compare the radiological impacts of the HTGR and the LWR. Based on the results of these studies, a technical basis exists for the allowance of siting of the HTGR closer to population areas. The HTGR can meet the radiological impact objectives of Appendix I of 10CFR50 with less radwaste equipment than the LWR.

Geological impediments to HTGR siting may only affect

Broad geological studies were performed to determine which areas of the U.S., if any, the HTGR-R due to its need of cavern storage for gases

would be unsuitable for siting an HTGR because of anticipated seismic requirements for the safe shutdown earthquake (SSE) or because of the allowable soil bearing pressure. Both studies showed only small areas where these factors may be of concern. Geological factors may be of most concern in the siting of configurations requiring cavern gas storage facilities. This is due to the requirement for stable rock or salt formations which are necessary for the storage of methane and synthesis gas (hydrogen and carbon monoxide). Detailed studies have not yet been performed to quantify the possible siting limitations caused by this factor.

Institutional restrictions to nuclear siting may not take into account the HTGR's radiological advantages

Institutional restrictions will probably have the most effect on HTGR siting. New nuclear siting criteria which call for more remote siting will probably govern the HTGR siting process until the radiological advantages of the HTGR are proven through operation. Additional institutional restrictions on the siting of the HTGR-R may exist due to the explosive potential and toxicity of its component gases.

4.4 Operation and Maintenance

The ability of the HTGR to withstand severe operational transients without adverse effects has been confirmed by Fort St. Vrain

The operational experience of Fort St. Vrain was reviewed, showing that most operational problems were non-reactor-related. Design of reactor auxiliary systems can be changed to improve helium purity and to limit water ingress into the PCRV, two major operational problem areas. Core power and temperature oscillations have been recorded, and a permanent fix has been installed. Several transients have been experienced which confirm the ability of the HTGR to withstand operational transients without adverse effects.

The HTGR-GT and HTGR-R have unique operational characteristics which need further study

The operational characteristics of the HTGR-GT and the HTGR-R are not as well defined as for the HTGR-SC due to the preliminary nature of the reference design. For the HTGR-GT, the interaction and startup of the two turbomachine loops have not been fully investigated. For the HTGR-R, the control and isolation of the reformer gases must be more fully examined.

The maintenance of the HTGR is expected to result in lower man-rem exposure rates

Exposure data were examined from Peach Bottom I and Fort St. Vrain and are compared to LWR units of comparable size. Based on this experience, projections are made for future HTGRs which are expected to yield significantly lower maintenance radiation exposures than current LWR units.

4.5 Fuel Cycle

The HTGR fuel cycle yields more efficient uranium utilization

The HTGR produces less plutonium and consumes less uranium per megawatt of electricity produced than the LWR under all fuel cycle scenarios.

The HTGR fuel cycle cost advantage is appreciable only when HEU fuels are utilized with uranium recycle

The traditional HTGR-SC fuel cost advantage over the LWR is reduced to parity when the HTGR is forced to use low enriched uranium (20%) LEU/Th fuel with no recycle. For the HTGR-GT and HTGR-R, this becomes a 10% disadvantage because the fuel must be designed for the higher core outlet temperatures. The fuel cost advantage of the HTGR only becomes apparent when HEU/Th fuel is utilized with full recycle.

4.6 Advanced Applications

The HTGR-SC can utilize sensible energy storage to serve the distributed process heat market

Within the present temperature regimes of the HTGR-SC, utilization of a sensible heat storage system provides relief of close-in siting concerns associated with the distribution of process steam to industrial customers. The heat storage system, if proven economical, could allow the HTGR to run at essentially full load, regardless of the customer's demand profile.

The HTGR-GT can progress to higher efficiencies

Through the use of an ammonia bottoming cycle or higher turbine inlet temperatures, the overall efficiency of the HTGR-GT may reach 50%. The economics of achieving this high efficiency have not been proven.

The HTGR-R has the potential to serve many markets

Through the use of the reformer product synthesis gas, the HTGR-R can serve the distributed heat market or provide product gases directly to synfuels processes or to steelmaking processes. Additionally, the HTGR-R can evolve to even more advanced configurations including thermochemical water splitting for the generation of hydrogen.

5.0 The HTGR-Steam Cycle

The total cost of power from the HTGR-SC is essentially equal to that produced by the LWR

Based on estimates performed by General Atomic Company and United Engineers & Constructors, the total cost of power produced by the HTGR-SC is essentially equal to the LWR. With HEU/Th fuel and full recycle, the HTGR-SC advantage is approximately 3%, which is within the uncertainty bandwidth. The estimates are for the equilibrium commercial plant and do not include first-of-a-kind (FOAK) costs.

The HTGR-PS/C version of the HTGR-SC is generally more economic than coal for production of steam, but projected costs are sensitive to assumptions

Comparisons of the cost of steam produced by the HTGR-PS/C version of the HTGR-SC against steam produced by a conventional coal plant generally show a significant cost advantage for the HTGR. These results, however, are very dependent on site-specific conditions and economic assumptions. For example, because the fuel costs for the coal-produced steam account for about 80% of the total steam cost, the results are very dependent on the coal cost escalation assumed. This study also assumed that both plants operate at a 70% average capacity factor. If an energy storage system is not available or is not economical and the units must operate below a 70% capacity factor, the cost of the HTGR steam will rise more relative to the coal steam because of the higher capital cost of the HTGR. Conversely, if coal costs and/or HTGR capacity factors are higher than expected, the HTGR would provide an even greater advantage.

An economic energy storage is needed with a distributed customer system to maintain full-power reactor operation during periods of low customer demand

The HTGR-SC appears to have a large potential market in the 2000-2020 time frame

When the market factors of Section 2.1 are analyzed for the HTGR-SC relative to its anticipated major competition, i.e., the LWR, the following factors are positive:

- Forecasted Energy Demand
- Siting Flexibility
- Plant Capabilities
- Regulation and Licensing

- Capital Risk
- Safety
- Personnel Radiation Exposure
- Fuel Cycle Flexibility
- Advanced Applications

The two negative market factors are:

- Technical Development Status
- Commercial Status

Economics is considered to be a neutral market factor for the HTGR-SC at the present time.

The present commercial status is the single most important barrier to the marketability of the HTGR-SC

The commercial status of the HTGR-SC must become acceptable to the utility market through the use of contractual agreements, warranties, service and fuel commitments, and cost- and risk-sharing arrangements. This factor remains the single most important barrier to the marketability of the HTGR-SC.

While several market factors offer formidable barriers to HTGR-PS/C commercialization, the large projected demand for economic industrial process energy may force resolution of the problems

Because the HTGR-PS/C will serve a different market than the HTGR-SC, and because it will probably have coal-fired facilities as its primary competition, many of the market factor evaluations differ from the HTGR-SC results. The only positive factor is Forecasted Energy Demand.

Negative factors which result are:

- Technical Development Status
- Commercial Status
- Nuclear Specific Market Factors
- Institutional Factors, i.e., reliability requirements and contractual arrangements

The following factors are currently considered to be neutral because of design and institutional uncertainties:

- Economics
- Siting Flexibility
- Regulation and Licensing
- Plant Capabilities

Despite the formidable barriers which the above negative factors represent, the projected demand for economic industrial process energy is large enough such that it may force timely resolution of the technical, commercial, and institutional problems such that a market could develop late in the study time period.

6.0 The HTGR-Gas Turbine

Relative to the LWR and the HTGR-SC, the HTGR-GT provides minimal economic incentive with dry or dry/wet cooling. The binary cycle HTGR-GT also shows minimal economic incentive.

Extensive cost tradeoff estimates were performed for the HTGR-GT. Also, cooling system studies were performed which for the first time quantified the economic advantage of the HTGR-GT performance with dry and dry/wet cooling relative to the LWR and coal-fired units. From these economic studies, the following conclusions can be drawn:

- The HTGR-GT with an ammonia bottoming cycle is more economic than a dry/wet-cooled HTGR-GT.
- For sites which require dry or dry/wet cooling, the HTGR-GT provides minimal economic advantage over the HTGR-SC and the LWR.
- The HTGR-GT provides economic competition to a coal-fired unit.
- The binary cycle HTGR-GT provides minimal economic incentive over the HTGR-SC and the LWR.

When the market factors of Section 2.1 are evaluated for the HTGR-GT relative to its anticipated major competition, i.e., the LWR, the following factors are positive:

- Forecasted Energy Demand

- Siting Flexibility
- Personnel Radiation Exposure
- Fuel Cycle Flexibility

Negative market factors include:

- Technical Development Status
- Commercial Status

The remaining market factors are considered to be neutral because of present design and institutional uncertainties.

Current cost estimates and performance evaluations point to the limited economic advantage of the HTGR-GT. Significant cost and performance improvements in the HTGR-GT are required to justify the cost of commercialization.

The economics of the HTGR-GT were evaluated as a neutral market factor relative to the LWR because of the near parity total power cost. However, parity or a relatively small cost advantage is not sufficient to justify the development costs of the HTGR-GT when the same economic performance can be obtained with the HTGR-SC. Also, large cost uncertainties are associated with the HTGR-GT relative to the LWR and HTGR-SC due to the conceptual design stage of the HTGR-GT. Therefore, it is concluded that future work must produce significant cost and performance improvements in the HTGR-GT to justify the expenditures needed to bring it into the commercial marketplace.

7.0 The HTGR-Reformer

Preliminary economic studies show the need for further design refinement

As a part of recent studies of the HTGR-R for the HTGR Lead Project identification effort, economic evaluations were performed on an initial design that was not optimized. The results yielded lower than expected plant output and higher than expected capital costs for both off-site and on-site methanation configurations. As a result, definite conclusions about the economic viability of the HTGR-R cannot be drawn at this time and further design refinements are required.

When the HTGR-R is evaluated against its anticipated major competition, i.e., coal-fired units, relative to the utility market factors, the following are positive:

- Forecasted Energy Demand
- Plant Capabilities

A negative evaluation results for the following market factors:

- Technical Development Status
- Commercial Status
- Institutional Factors

The remaining market factors are considered to be neutral because of present design and institutional uncertainties.

The market potential for the HTGR-R cannot be quantified at this time due to the early stage of design

As was the case with the HTGR-PS/C, the concept of a nuclear unit supplying a process energy distribution network provides several unique formidable barriers to the commercialization of the HTGR-R. However, the economics of competing systems as well as the large forecasted demand for process energy may force the solutions to these problems. Because of the large uncertainties in the current economic evaluations, further design and study are required before comparable costs for the HTGR-R can be obtained; therefore, the marketability of the HTGR-R cannot be determined at this time.

1.0 INTRODUCTION

1.1 OVERVIEW

Work is progressing towards the achievement of the significant potential offered by the High Temperature Gas-Cooled Reactor (HTGR). This document presents a technical and market assessment of the HTGR, beginning with a discussion of the history of HTGR development and its associated utility support. HTGR market projections are presented as well as discussions of utility systems analysis techniques which provide insight to the effect of the HTGR on individual utility systems. Utility-oriented assessments of the technical status and generic benefits of the HTGR are also presented.

This Assessment, prepared by Gas-Cooled Reactor Associates (GCRA), presents information that is intended to be of benefit to any institution or organization in its evaluation of the HTGR and is an important component of the information package which will be utilized to select the HTGR Lead Project.

1.2 BACKGROUND

1.2.1 HTGR Development

The gas-cooled reactor (GCR) is the oldest type of nuclear power reactor. Farrington Daniels performed pioneering studies at Oak Ridge National Laboratory (ORNL) in the mid-1940s on the development of a helium-cooled direct cycle (gas turbine) reactor with ceramic fuel and moderator and a U-235/Th/U-233 fuel cycle. The first gas-cooled reactor power station at Calder Hall, however, used CO_2 as a coolant and natural uranium as a fuel and went into operation in the United Kingdom in 1956. Calder Hall initiated the first generation of gas-cooled nuclear power systems--the Magnox reactors. Thirty-six Magnox systems with a combined electrical rating of 8200 megawatts are now in operation (see Table 1.2-1). The available operating experience acquired over many years is comprehensive, and by the end of 1979 it had covered nearly 600 reactor years. Figure 1.2-2 compares global gas-cooled reactor capacity with that of other nuclear power reactors. The oldest GCR system has been in operation for more than 20 years.

The Advanced Gas-Cooled Reactor (AGR) represents a further evolution of the Magnox reactor concept in the United Kingdom. The significant improvement is in a new fuel element design which allows higher gas temperatures, resulting in conditions equivalent to those of modern conventional power plants. Other characteristics of Magnox reactors such as the graphite moderator, integrated steam generators, prestressed concrete reactor vessel (PCRV) and core loading during power operation have been retained. At the present time eleven AGR systems with a combined electrical rating of 6,232 megawatts are in operation or under construction.

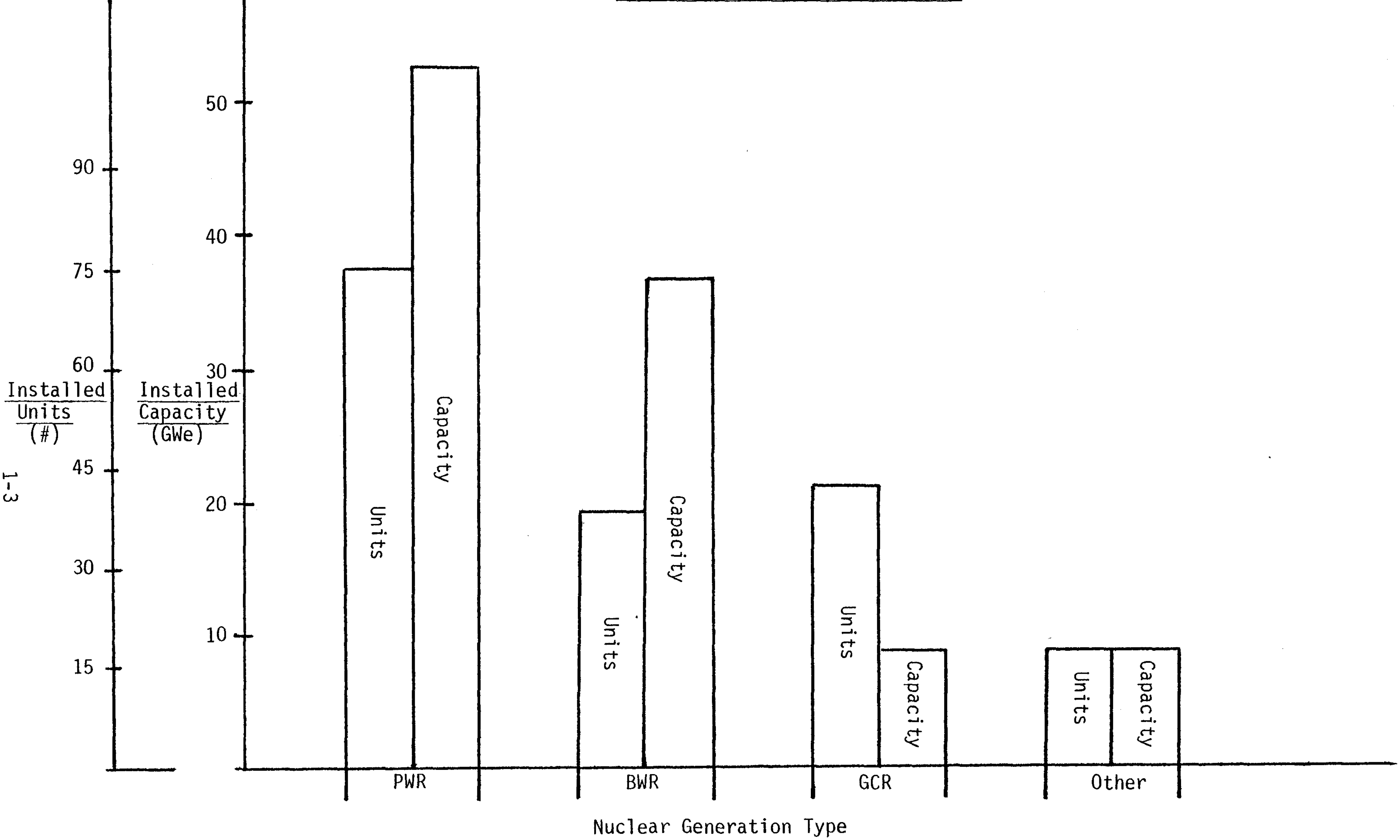
Table 1.2-1

Gas-Cooled, Graphite-Moderated Reactors

Facility	Number of Reactors	Net Electrical Rating in MW	Commercial Operation Date
Magnox Reactors			
Calder Hall	4	200	9/56
Chapel Cross	4	200	11/58
Marcoule G2,63	2	80	4/59, 5/60
Berkely	2	276	6/62, 10/62
Bradwell	2	300	6/62, 11/62
Latina	1	150	1/64
Chinon 1	1	80	2/64 - 4/73
Hunterston A	2	320	5/64, 9/64
Chinon 2	1	210	2/65
Trawsfynydd	2	500	2/65, 3/65
Hinkley Point A	2	500	5/65
Dungeness A	2	550	9/65, 12/65
Sizewell A	2	580	1/66, 3/66
Tokai 1	1	159	7/66
Chinon 3	1	400	8/67
Oldbury	2	600	1/68
St.-Laurent-des-Eaux 1	1	460	3/69
St.-Laurent-des-Eaux 2	1	515	8/71
Wylfa	2	1180	11/71, 1/72
Bugey 1	1	540	4/72
Vandellos	1	480	7/72
AGR			
Windscale	1	32	2/63
Hinkley Point B	2	1250	6/76, 1/77
Hunterston B	2	1250	6/76, 5/77
Dungeness B	2	1200	80/81
Hartlepool	2	1250	81/82
Heysham	2	1250	81/82
HTGR			
Dragon	1	(20$_{th}$)	10/64 - 10/76
Peach Bottom	1	40	6/67 - 10/74
Fort St. Vrain	1	330	1979
AVR	1	15	12/67
THTR	1	300	1982

Figure 1.2-2

Free World Nuclear Power Plants



The HTGR is an advanced development of the Magnox and AGR reactors aimed at further increasing the performance of the gas-cooled, graphite-moderated reactor. This advancement required modification of the fuel element, the use of coated fuel particles and a change from CO_2 to helium as the primary circuit coolant. The resulting concept features high plant efficiency, low fission product release and a relatively clean primary loop.

The 20 megawatt thermal (MWt) DRAGON reactor, a joint development of European Organization for Economic Cooperation and Development (OECD) countries, was the first HTGR and was commissioned in 1964. The reactor was a test facility which supplied valuable experience in the field of fuel element development, core design, helium technology and high temperature metallurgy. This reactor was decommissioned late in 1975 after more than ten years of successful operation.

The first HTGR to produce electricity was the 40 megawatt electric (MWe) Peach Bottom prototype which began commercial operation in June 1967. The Peach Bottom plant was decommissioned in October 1974 after a total of 1349 equivalent full-power days and production of more than 1.38 billion kilowatt hours of electricity for the Philadelphia Electric Company. This reactor served as an invaluable test bed for the fuel designed for large HTGRs and for reactor physics studies. The average gross plant efficiency over its 7-1/2 year life was 37.2% and the nuclear steam system availability was 88%. All reactor systems in Peach Bottom performed without major problems. The reactor control system operated exceptionally well, and the steam generator operated throughout its entire life without experiencing failure or plugging of tubes.

In late 1976, the 15 MWe AVR HTGR went into operation in the Federal Republic of Germany. Its purpose was to demonstrate the feasibility of an HTGR with spherical fuel elements and high operating temperature. Since its initial operation date, over 1.5 million spherical fuel element movements have been made, with some fuel exhibiting burn-up values of 180,000 megawatt days per ton. In 1974, core outlet temperatures were raised to 1742°F (950°C), a temperature which is well in excess of that currently proposed for near-term HTGR systems. In over ten years of operation, AVR has attained an average availability of 78%, with its annual availability in 1976 reaching 92%.

The 330 MWe Fort St. Vrain HTGR was built for the Public Service Company of Colorado under the Power Reactor and Demonstration Program of the U.S. Atomic Energy Commission. It contains a number of design features which are new to power reactor systems in the U.S., namely, hexagonal graphite fuel assemblies incorporating pyrocarbon and silicon-carbide coated uranium and thorium dicarbide fuel particles, once-through modular steam generators with integral superheaters and reheaters, steam-driven helium circulators, and a PCRV. Construction of this plant was completed in 1973, and criticality was first achieved in January 1974.

To date, Fort St. Vrain has generated over 1.2 billion KWhs. The plant has successfully operated up to 70% power, with higher level operations restricted by the Nuclear Regulatory Commission until further testing and review are completed. While Fort St. Vrain has experienced some difficulties in its rise to power, it has provided critical confirmation and demonstration of many key HTGR concepts. Significant is the HTGR's excellent fuel performance and the resulting low radiation exposure to plant personnel documented during the refueling outage in 1979. There has been excellent correlation between predicted fuel performance and observed data. Radiation dose rates on primary system components have been and continue to be low enough to warrant substantial direct contact maintenance. Other major contributions of Fort St. Vrain have been in the areas of core physics confirmation, plant control and response, and plant performance at high temperatures. Plant operating experience to date has demonstrated predictable, easily managed performance even during extreme modes of operation including temporary loss of forced cooling. The high core heat capacity has shown temperature transients to be slow, predictable, and easily controlled. Fort St. Vrain has also demonstrated high performance and high temperature capabilities. Operation to date has achieved 1400°F primary loop and 1000°F steam temperatures--the highest of any nuclear plant in the U.S.

The long-term goal stated for the German HTGR Development Program is the market introduction of the HTGR for process heat and electricity production. The short-term goal is to demonstrate that HTGR technology is feasible for both applications and that it can be economically applied. A current HTGR project in the Federal Republic of Germany (FRG) is the THTR. THTR is a 300 MWe demonstration plant for the HTGR Steam Cycle system and which uses the spherical fuel element concept introduced with AVR. The completion of this power plant has been given first priority in the German HTGR Program, and approximately 80% of the total construction is now complete. The original construction schedule of 61 months has been extended to the current estimate of 130 months by several major licensing delays. The successful operation of THTR is considered to be a prerequisite for future HTGR commercialization efforts in that country. Startup of THTR is currently projected for 1983.

There is a strong sentiment within the German HTGR Program to develop a follow-on construction project to the THTR-300. With the increasing demands on non-oil-producing nations to find alternate energy sources, there is an added interest in the FRG in coal liquefaction and gasification. The obvious link between a high-temperature nuclear heat source with these processes has attracted the interest of the German Coal and Gas Boards and the electric utilities. These three groups have been contracted by the government to conduct a study to determine the feasibility of coupling an HTGR steam/electricity-producing plant with a coal gasification plant as a possible near-term project. This project is seen as a reasonable first step toward the eventual goal of deploying the HTGR as a source of high-temperature process heat by linking the lower risk HTGR-SC with a coal gasification plant. This project also provides incentives to the German HTGR Utility Groups, since it further advances the HTGR technology which, in their view, is a future source of safe and clean electric power.

1.2.2 Utility Support

Gas-cooled reactor development in the United States has a 25-year history of utility involvement, beginning in the early 1950s with the Rocky Mountain Nuclear Power Group. This group of eleven organizations, which included five non-utility members, evaluated potential nuclear power alternatives. As a result of their studies, they chose the HTGR system at General Atomic Company for utility support. In 1958, eleven utilities known as the Rocky Mountain-Pacific Nuclear Research Group, sponsored research and development efforts leading to the design of an HTGR system. Also, in 1958, 53 utilities formed to sponsor the design and construction of the 40 MWe Peach Bottom prototype HTGR. This group was known as the High Temperature Reactor Development Associates (HTRDA). Concurrent with developing Peach Bottom Atomic Power Station, 23 members of HTRDA embarked on a U/Th fuel cycle development program, which established the basis for the fuel cycles used in HTGRs. Another group of 7 utilities, known as Empire State Atomic Development Associates (ESADA), sponsored a 500 MWe HTGR design as well as research and development on major components for gas-cooled reactors. The results of this work established the principal design features of key components, including the helical coil steam generator and the helium circulator for the steam cycle plant. Additionally, 11 utilities in western states formed the Advanced Reactor Development Associates (ARDA). This group funded conceptual studies on a fully integrated NSS within a PCRV, a distinguishing feature which has become the basis for all subsequent HTGR designs.

Direct utility involvement in the HTGR-GT began in 1971 with guidance provided through the Utility Steering Committee. This support grew over the years to the extent that the number of utilities and related utility groups, such as ESEERCO and New England Electric, represented some 31 utilities.

During the 1971-1974 time period, commercial orders were taken for 10 HTGR-Steam Cycle (SC) plants by General Atomic Company. During 1975, these orders and the commercial option for the HTGR-SC were canceled or withdrawn. The time frame 1976-1977 saw a period of critical re-evaluation of gas-cooled reactor technology. A number of technical and commercial assessments of gas-cooled reactors were performed. A particularly important study was one performed by Arthur D. Little, Inc. for the Energy Research and Development Administration (ERDA), now the Department of Energy. The A. D. Little study evaluated the economic and technological feasibility of gas-cooled reactors and generally concluded that the development of this reactor type should be continued through commercialization because of the potential realization of large economic, conservation, safety, and environmental benefits relative to alternative nuclear and coal-fired power plants.

The culmination of all of these studies was an ERDA-funded commercialization study conducted by RAMCO, with substantial inputs by government, industry and the utilities. The significant conclusions of the study were: (1) the user industry must provide leadership and overall program coordination; (2) the industrial base must be broadened to assure a stable and competitive supply industry; and (3) any HTGR program must be adopted as part of the National Energy Plan and, hence, receive stable and affirmative government support.

Representatives of 30 utilities met with ERDA in August 1977 to discuss the future of thermal gas-cooled reactor technology. The outgrowth of this and further meetings was the incorporation of Gas-Cooled Reactor Associates on February 6, 1978.

With the formation of GCRA, utility support of the HTGR was concentrated within one organization. As a result, the Utility Steering Committee and Program Review Committee formed in 1977 to provide utility input to HTGR development became the currently active Technical Advisory Committee. Beginning in May 1979, GCRA initiated its first formal attempt to broaden utility participation in the HTGR Program. Through these efforts, utility support of and participation in GCRA have grown to represent approximately 25% of the U.S. generating capacity. The utilities currently involved in GCRA are listed in Table 1.2-3.

At the present time, efforts are also under way to broaden the GCRA constituency to include process heat users of HTGR technology from the petroleum, chemical, and steel industries.

1.3 STUDY APPROACH

The GCRA utilities have a substantial investment in and extensive experience with nuclear power. GCRA participants represent approximately 25% of the installed nuclear capacity and approximately 35% of the nuclear capacity under construction. This provides a most credible comparative base for assessing nuclear alternatives such as the HTGR. With this as background, the approach taken in this Assessment is one in which the HTGR is evaluated from the perspective of its eventual users and operators--the utility industry. To achieve this, the results of previous efforts as well as new original work will be integrated into this document.

Section 2 will present projections of future electrical and process heat energy demands in order to attempt to quantify the potential market for the HTGR. These projections are the result of work performed by consultant organizations under contract to GCRA and will be compared to projections of other national organizations.

Section 3 will provide an analysis of the effects of the HTGR on specific utility systems as well as extrapolated results on a national basis. The primary method of analysis for this section is the utilization of General Electric Company's Optimized Generation Planning (OGP) code to measure the effects of the HTGR on a representative utility system.

Section 4 presents assessments of the various recognized incentives for HTGR commercialization. These assessments are intended to present a

Table 1.2-3

Utilities Supporting GCRA

Arizona Public Service Company
City of Tacoma
Colorado-Ute Electric Association
Delmarva Power & Light Company
Empire State Electric Energy Research Corporation
- Central Hudson Gas & Electric Corporation
- Consolidated Edison Company
- Long Island Lighting Company
- New York State Electric & Gas Corporation
- Niagara Mohawk Power Corporation
- Orange & Rockland Utilities
- Rochester Gas & Electric Corporation

Florida Power & Light Company
Gulf States Utilities
Idaho Power Company
Northeast Utilities Service Company
- The Connecticut Light & Power Company
- The Hartford Electric Light Company
- Western Massachusetts Electric Company
- Holyoke Water Power Company

Pacific Gas & Electric Company
Pacific Power & Light Company
Philadelphia Electric Company
Public Service Company of Colorado
Public Service Company of New Mexico
Public Service Electric & Gas Company
Puget Sound Power & Light Company
Salt River Project
San Diego Gas & Electric Company
Tennessee Valley Authority
Washington Public Power Supply System

balanced picture of the HTGR's characteristics relative to the present status of HTGR technology. This section will also analyze these characteristics and their uncertainties relative to their perceived effects on the HTGR's marketability, based on the user's point of view.

Sections 5, 6 and 7 present technical descriptions, and economic and market assessments of each of the three reference HTGR systems, namely the HTGR Steam Cycle, Gas Turbine, and Reformer. The information presented in these sections is based on work performed during 1979 and 1980 which was aimed at providing information leading to the selection of an HTGR lead plant project. The process by which the selection will be made and the documentation on which it will be based will be assembled in four application summary packages, one for each of the four HTGR Lead Project options. For more information on these four options, see Reference 1.

2.0 POTENTIAL MARKET PROJECTIONS

The ultimate objectives for the application of the HTGR are twofold: the generation of electricity and the production of process heat. For electricity production, the utility industry is the obvious market. Process heat includes many potential applications of the HTGR that may eventually involve industrial owner/operators of HTGR plants. However, the potential HTGR market for the foreseeable future lies with the utilities due to the inherent capital intensity and the regulatory characteristics of the nuclear option.

The utility industry is capable of generating a demand for an all-electricity-producing HTGR or a multipurpose HTGR which produces both electricity and process heat. The markets for these potential applications will be examined in this section.

2.1 HTGR MARKET FACTORS

The factors affecting the market for HTGRs are varied and complex. Further, they are overshadowed by the question of the political viability of the nuclear option in general. It is beyond the scope of this document to examine this latter issue; therefore, it is assumed that the current political uncertainties of the nuclear power market will have been favorably resolved in the time frame pertinent to HTGR commercialization (2000-2020). Further, it is not reasonable at this time to assume that the HTGR would survive or cause a reversal of an adverse political decision on the future of the nuclear option.

The market factors discussed in this section are those which have been identified as having the greatest potential impact on the HTGR's introduction to the commercial market. This Assessment will examine all of these briefly, with some of the more key factors discussed in greater detail in later sections of this document.

2.1.1 Generic Market Factors

When a utility makes a decision to purchase a particular type of generation facility, it considers several generic factors regardless of the type of generation being considered and evaluates the alternative choices with regard to these factors. The generic market factors that affect a utility's decision to make a particular capital expenditure are discussed below with reference to the HTGR:

- Forecasted Energy Demand - The projected growth rates of the demand for energy in the forms of electricity and process heat have steadily decreased during recent years due to conservation and the general decline in economic and population growth rates. Lower growth rates will have a twofold effect on the utility market. First, new units ordered will tend to be of smaller size in order to limit unnecessarily high reserve margins and to minimize capital investment requirements. The expected trend toward smaller baseload additions has been considered in adopting current HTGR reference designs. The economic effects of deploying smaller baseload units on utility system total power costs are addressed in Section 3.0. Second, the lower growth rates will decrease the demand for new capacity, thereby directly affecting the potential HTGR market size. Projected growth rates and market sizes are treated in greater detail in Section 2.2.

- Siting Flexibility - There must be a suitable location for a new generating station. Whereas once system configuration, stability, and economic considerations were the determining factors in site selection, now site suitability is also determined by environmental rules and regulations, public health and safety issues, and public intervention. Also, the number of available sites for new stations is limited for most utilities; therefore, the technology which is most adaptable to specific site conditions while still satisfying regulatory and environmental requirements will possess a great advantage over its competitors. The HTGR has evaluated water consumption and radiological advantages in this area. These issues are examined further in Sections 4.2 and 4.3, respectively.

- Technology Development Status - A new power technology, to be considered as a viable alternative by the utility market, must be accepted as having performance and cost characteristics which have uncertainties associated with them which are comparable to those associated with the other choices with which it must compete. Developing and demonstrating the current energy technologies have required decades and billions of dollars. Alternatives can be expected to require the same to bring them to the same technological status. The HTGR has progressed through previous development and demonstration programs. It is recognized, however, that extensive research, design, and development are still needed to bring the HTGR to viable commercial status.

- Regulation and Licensing - A new alternative technology system is at a disadvantage in a utility analysis if the regulations governing its siting, design, construction, and operation are not sufficiently developed to allow analysis of their impact on performance, costs, and schedules. If this is the case, the less mature alternative cannot be realistically compared with the other choices. Correspondingly, the uncertainty level of the licensability of the alternatives must also be comparable. The HTGR program intends to minimize licensing uncertainty by incorporation of a pre-licensing review program to establish licensing criteria for HTGRs. In addition, the HTGR Lead Project is intended to provide adequate licensing experience prior to commercialization. Section 4.1 provides a current assessment of the licensing issues associated with the HTGR.

- Commercial Status - Important in the utility's decision to procure a particular type of generation is the adequacy and reliability of the supply system behind the alternative. Regardless of the presumed merits of the alternative, a clear commitment on the part of a credible segment of the supply industry is necessary for the alternative to receive consideration from the utility industry. Engineering, manufacturing and field services must be made available by the supplier to the utility for the life of the product.

In addition, an alternative technology must be sufficiently firm in terms of cost, regulations, licensing, and warranties so as to not require commercial terms and conditions which are substantially different from the terms and conditions under which competitive alternatives can be procured.

- Plant Capabilities - The capabilities of alternative technologies must be able to meet the specified requirements of the utility industry. For generation alternatives, a new technology must at least be able to offer the same capabilities as do the currently available technologies and should offer additional features to provide an incentive for commercialization. Specifically, load-following capability, net plant output, planned and forced outage rates and maintainability are all factors with which a new generation technology will be compared to existing alternatives.

  The capabilities and operating characteristics of the three HTGR systems will be evaluated in Section 4.4-1.

- Economics - Economic considerations constitute one of the most important factors in the selection of any capital expenditure decision. Utility practice, law, and normal business prudence generally dictate the choice of a generation system which provides the lowest cost of power, consistent with meeting all applicable regulations and reliability criteria.

  For a generation alternative, the utility must examine all of the component costs which comprise the total power costs. These are the capital cost, fuel cost, and operation and maintenance (O&M) costs. It is the interaction of these factors on the total power cost and how that total cost compares to the available alternatives that will affect the utility's selection. The reliability of the generation alternative is also an important economic factor. The utility must take into account the amount of time that the generation will not be available and must be replaced with other forms of capacity. A new generation alternative must have an eventual reliability comparable to its established competitors.

  Sections 5.2, 6.2, and 7.2 provide economic analyses of the HTGR systems, comparing them with competing generation alternatives.

2.1.2 Specific Nuclear Market Factors

There are several factors which affect primarily the nuclear power generation market and, therefore, must be examined as they will have a bearing on the HTGR's market penetrability. In order to understand how the HTGR will be evaluated against the LWR with regard to these factors, one must be familiar with the design and inherent features of the HTGR. Sections 5.1, 6.1, and 7.1 provide summary information in these areas.

- Capital Risk - This factor, even though economic in nature, is generally considered unique to nuclear alternatives and must be considered separately. As a result of the Three Mile Island incident, both the utility industry and the investment community have perceived greater capital risks with nuclear power--specifically, that a combination of human and mechanical failures can render a billion dollar capital investment inoperative for an indefinite period of time. This realization has caused some of the utility industry to take a "hard second look" at the nuclear option. The result has been the indefinite stagnation of the nuclear market.

  A new nuclear technology which has less capital risk than the present LWR would have a perceived advantage in the market, possibly even to the point of commanding a higher capital cost. The HTGR has the potential for decreased susceptibility to capital risk. This is directly the result of its inherent safety and operability characteristics. These are evaluated in Section 4.

- Safety - Even in the wake of Three Mile Island, the safety experience record of LWRs is unparalled in the energy production sector. While the LWR has met all safety and licensing requirements imposed by regulatory agencies, the LWR must provide rapid response to transient conditions affecting core cooling. Following a design basis accident, LWR fuel damage can begin to occur within a few minutes if the mitigating systems fail to function. A new technology such as the HTGR which would allow a longer time period for operator corrective action would have a perceived advantage over the present LWR system. An assessment of the HTGR's characteristics in this area is found in Section 4.1.

- Personnel Radiation Exposure - Operating and maintenance personnel at nuclear power plants receive doses of radiation in excess of background during performance of their duties. The NRC places limitations on the amount of exposure that can be received over a set time period. When the exposure limit is reached, the employee may not continue to work in "hot" areas until the beginning of the next exposure time period. This leads to hiring of additional personnel in stations where high exposure rates are experienced and, therefore, increases costs. This factor is becoming a major element of the operation and maintenance costs for the operating LWR plants. A new nuclear technology which has the inherent feature of significantly reducing personnel exposure rates would have an advantage over existing systems. A further discussion of the HTGR's projected and documented performance in this area is found in Section 4.4.

- Fuel Cycle Flexibility - Future directions for nuclear fuel cycles are complicated by uncertainties arising from national policies, economic factors, and industry commercialization problems. It is desirable for utilities to have access to reactors that can operate economically on a once-through fuel cycle in the near term but can accommodate more efficient fuel cycles as policies and facilities allow. This consideration has not traditionally been a major factor in the utility selection process because it was generally assumed until recently that a closed fuel cycle would be available in the near term. Because the various fuel cycle options will not become available for at least a decade, a utility must consider the effects that a changing fuel cycle will have on its reactor systems. A reactor that can operate economically and efficiently with several anticipated fuel cycles would be advantageous. The HTGR's adaptability to fuel cycle changes is assessed in Section 4.5.

- Advanced Applications - Some utilities have shown interest in expanding and/or enhancing their present energy supply markets through the sale of waste steam from generating stations to industrial customers. Several utilities have been in this "process heat" market for a number of years. As fuel oil for industrial boilers becomes more expensive, it is reasonable to expect that an expanded market could develop for nuclear or coal-fired process heat that is generated in a central station and distributed by a utility to industrial customers.

  The HTGR has the unique potential for becoming not only a source for electric power but also a substitute for fossil fuels in process heat applications. The reforming variant of the HTGR is aimed at capturing a significant portion of this market. Also because of its higher temperature capabilities, it is the only nuclear heat source that can be utilized in other advanced applications such as hydrogen generation. A further discussion of these advanced applications is presented in Section 4.6.

The above factors are those which are perceived to play an important role in the utility decision-making process. The utility industry's evaluation of the HTGR relative to these factors will determine its ultimate market potential. The remainder of this document will provide the preliminary results of such an evaluation and will project the resultant effects on the potential HTGR market.

2.2 ENERGY DEMAND

One of the principal market factors identified in Section 2.1 is Forecasted Energy Demand. The correlation is obvious: the higher the demand for energy, the greater the demand for energy generation. In this section, the projected potential markets that will exist by the year 2020 will be presented for both electrical and process heat energy.

2.2.1 Electrical Forecast

The equation which predicts future energy demand is more complex than it was only ten years ago. Conservation, cogeneration, and solar energy are new trends which are having substantial impacts on predictions of installed capacity requirements for the nation's utilities.

There are several sources of projections for future electrical energy demand such as EPRI, DOE and NERC. These projections only touch on the demand expected between the years 2000 and 2020, which is the time frame of interest for the commercialization of the HTGR. In order to perform a more detailed analysis of this period, GCRA contracted with the Hanford Engineering Development Laboratory (HEDL) to perform a study of the market potential for dry cooling of power plants in this time period. In order to quantify the forecasted electrical demand, HEDL utilized a computerized forecast model, DND. This model utilizes an econometric approach which considers the cause and effect relationships between energy demand and the factors which influence the demand. Demand models were developed for each of the three consuming sectors: residential, commercial, and industrial. Each model utilizes the principle of elasticity of demand in formulating an algorithmic equation for the model.

The independent variables which must be input to the model are:

- Population Growth Rates
- Real Per Capita Income
- Value Added in Manufacturing
- Number of Residential Customers
- Consumer Price Index
- Coefficients of Elasticity

The factor which has the dominant influence on the results is the population growth rates. These were derived from the Oak Ridge National Laboratory (ORNL) MULTIREGION population projection system. A Series II growth rate was assumed, i.e., 2.1 lifetime births per woman. A further discussion of the details of this method of forecast modeling is found in Reference 2.

The DND code utilized a predicted growth rate in electrical demand of 2.5% during the period of 2000 to 2010 and 1.5% during the period of 2010 to 2020 for a median case. This compares to EPRI's projection of 3.0% between 2000 and 2020, which was used as a high-growth case (Reference 3), and DOE's projection of 2.3% (Reference 4). The DND forecasted demand in each of the 99 Water Resource Council Aggregated Sub-Areas (ASA) was utilized to predict installed capacities for the median case by NERC region. The predicted capacities are given in Table 2.2-1. These values assume an average to peak load demand ratio of .65 and a reserve margin of 30%.

Table 2.2-1

Forecast of Installed Capacity by NERC Region in GW

Region	1980*	2000	2010	2020
ECAR	92	242	310	360
ERCOT	43	94	120	139
MAAC	47	83	106	123
MAIN	46	117	150	174
MARCA	26	60	77	89
NPCC	52	95	122	142
SERC	123	296	379	440
SWPP	54	156	200	232
WSCC	107	226	289	335
Total	590	1369	1753	2034

*Current NERC projection

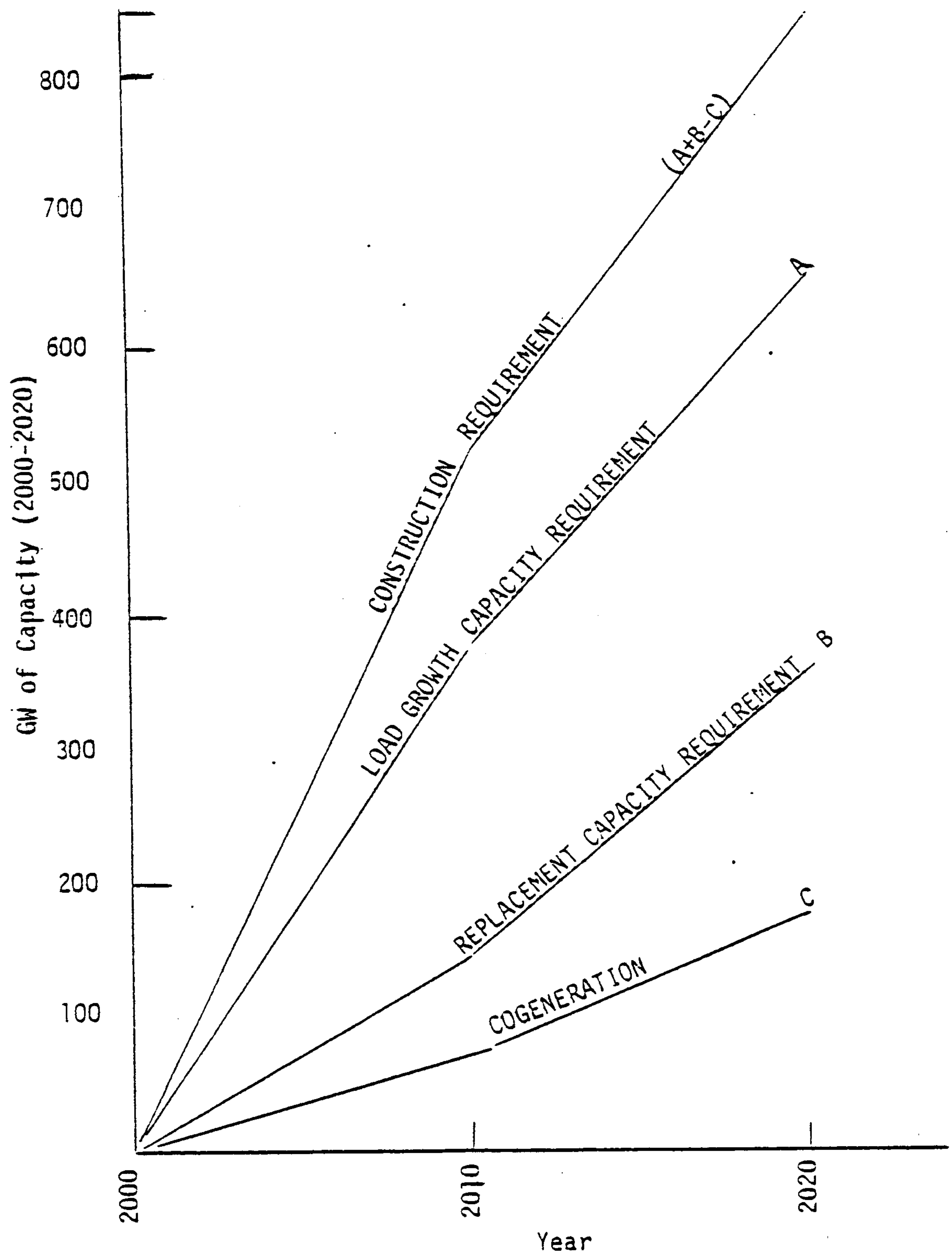
In comparison with the above numbers, EPRI predicts 1300 GW installed capacity in 2000 and 2470 GW in 2020, assuming a 20% reserve margin (Reference 3).

To utilize the above information to project future market size, a projection must be made of the amount of capacity that will be retired and thus will have to be replaced during this time period as well as any cogeneration capacity that might be added. Figure 2.2-2 shows the calculation of the amount of new capacity that will need to be constructed between 2000 and 2020 based on the median case assumptions. Based on these results, approximately 850 GWe of central station capacity will be added between 2000 and 2020.

The 850 GWe to be added between 2000 and 2020 is greater than the maximum market that will be available to the HTGR. Fossil, solar, geothermal and biomass central generating stations will constitute a portion of this installed capacity. As a result, the portion of the market available to nuclear generation is difficult to predict. Nuclear's share of the market in the year 2000 is expected to be between 235 and 275 GW (Reference 4) based on plants currently under construction and on order. Assuming that this percentage share will increase due to unavailability of oil and natural gas for electricity production after 2000, HEDL predicted that the nuclear capacity to be added between 2000 and 2020 would amount to approximately 430 GWe. This market, which is based on relatively conservative assumptions, still presents a rather sizeable potential market for the HTGR.

Figure 2.2-2

Calculation of Capacity Construction Requirement 2000-2020



2.2.2 Process Heat Forecast

The HTGR has generated additional interest within the energy industry because of its ability to supply high temperature heat to industrial users for a wide variety of applications. This section will attempt to quantify the future demand for these potential applications.

In considering the HTGR as a potential process heat energy source, three specific process heat market segments have been addressed. These include the following:

1. Reforming Industries - In this specialized segment of the chemical processing industry, steam reforming of natural gas is a principal constituent of the process. Ammonia, methanol, and hydrogen production are important examples.

2. Synfuels - The developing synfuels industry includes shale oil, coal liquefaction, and coal gasification.

3. Distributed Energy - In the distributed energy market, direct heat or process steam is distributed to a wide variety of industrial processes.

In the reforming industries, ammonia and methanol are the primary products produced by steam reforming of natural gas. Ammonia is the third-ranked industrial chemical (16 million tons in 1978). About 75% of the U.S. production of ammonia goes to fertilizer production, which is estimated to experience demand growth of 3-4% per year (Reference 5). Therefore, a likely annual demand of 36 million tons is projected by 2000. The future demand for methanol is hard to predict. Methanol will be produced as a by-product of the synthetic fuels from coal program; therefore, it is unlikely that large increases in the demand for methanol would be met by increasing the amount produced by natural gas reforming. As for hydrogen, it currently is produced as a by-product of many industrial processes and is used as a reactant or fuel for related processes. Chemical and Engineering News, May 15, 1978, predicts demand for hydrogen to grow approximately 10% per year. At present, most hydrogen is being manufactured by steam reforming of natural gas; however, technologies which utilize less expensive feedstocks, such as water splitting, are currently being developed. The latter are not expected to be commercially available until after 2000 but may be adaptable to use with the HTGR.

In the emerging synfuels industry, shale oil recovery as well as coal liquefaction and coal gasification are areas in which the HTGR can supply heat to increase the efficiency of the process. The amount of synfuels capacity that will be needed to satisfy the shortfall in supply vs. demand was estimated in Reference 37. The total synthetic fuels production forecast is shown in Table 2.2-3, which also shows the number of synthetic fuels plants required. The capacity of each of the 160 liquids plants is assumed to be 50,000 barrels/day, which translates into a 32% share of the total expected supply of liquid

Table 2.2-3

Synthetic Fuels Production Forecast
(thousand crude oil equivalent barrels per day)

SUPPLY	1980	1985	1990	2000	2010	2020
Synthetics						
Coal Gas	0	43	172	450	870	1,799
Liquids	0	27	260	1,712	5,106	7,990
SUBTOTAL	0	70	432	2,162	6,076	9,789
Conventional	26,976	27,612	28,889	30,227	26,750	25,915
TOTAL	26,976	27,682	29,321	32,389	32,826	34,704
Synfuels as Percent of Supply	0	.3	1.5	6.8	18.5	28.2

Synthetic Fuels Plants Required
(Cumulative Total)

	1980	1985	1990	2000	2010	2020
Coal Gas	0	1	4	10	20	41
Liquids	0	1	5	34	104	160
TOTAL	0	2	9	44	124	201

Source: Reference 37

petroleum in 2020 being produced by synfuels plants. Included in these 160 plants are a number of shale oil plants as well as coal liquefaction plants. The coal gasification plant projection of 41 plants by 2020 represents a production capability of approximately 18% of the total supply of natural gas for that year.

Depending upon the specific HTGR and synfuels technologies utilized, the HTGR nuclear heat source can displace a substantial fraction of the coal which would otherwise be burned in the synfuels process. Table 2.2-4, which has been adapted from Reference 41, depicts the principal characteristics of the SRC-II process, both conventional and with the HTGR in two configurations. As can be seen in the table, a substantial improvement in coal utilization can be achieved with the HTGR-SC. With the HTGR-R, nearly all of the heat contained within the input coal is ultimately contained in the product fuel. Similar investigations (Reference 6) indicate that the yield of product per ton of coal feedstock using hydrogasification can be increased by up to 26% with an HTGR which produces steam and electricity. Reference 6 also indicates that the HTGR-R used in conjunction with a direct H-Coal liquefaction process can increase the liquid product yield by 13% per ton of coal feedstock.

The potential for increased coal utilization using the HTGR could be a significant factor with regard to resource utilization and environmental impact. In addition to preserving coal for its optimum uses in the transportation and chemical industries, the reduced mining requirements and air pollution per unit of product may facilitate meeting synfuel production goals.

While the potential for the HTGR in the synfuels industry appears substantial, it is not yet possible to predict the number of plants which would be suitable for utilization of an HTGR heat source in the 2000-2020 time frame. Future studies will attempt to further address this subject.

The third area in which a perceived major market exists for HTGR-generated process heat is the distributed heat market. Table 2.2-5 from Reference 6 shows the projected energy requirements through 2000 for the five largest energy consuming industries which account for 72% of all industrial energy consumption. This information portrays the potential size and growth of the industrial energy market.

Because the HTGR is envisioned to supply process steam directly or via a means of energy distribution and storage such as the thermochemical pipeline (see Section 7), a breakdown of the potential industrial energy market by steam and direct heat is necessary. GCRA contracted with General Energy Associates, Inc. to provide a profile of the existing process heat market and to project the growth of this market out to 2020. Reference 33 presented the results of that study, which are summarized in Table 2.2-6. These results show that the process steam portion of the industrial process heat market is projected to increase slightly to 48%, for a total of 33 quads in 2020. Table 2.2-6 also indicates the thermal rating of present industrial

Table 2.2-4

Comparison of Nuclear and Non-Nuclear Coal Liquefaction Processes (for Jet Fuel Production*)

	Conventional	850°C HTGR	750°C HTGR
Process	SRC-II	SRC-II Nuclear Reforming	SRC-II Nuclear Steam
Coal Feed, Tons/Day	32,210	21,700	25,700
Nuclear Heat Source			
Reforming,** MWt	--	905	--
Steam, MWt	--	1,155	1,482
Product Output			
BPD	90,000	90,000	90,000
Tons/Yr	4.4×10^6	4.4×10^6	4.4×10^6
Thermal Efficiency, %	59	67	63
Product/Coal Ratio, BBL/Ton	2.8	4.2	3.5
Heat in Product/Heat in Coal	0.59	0.95	0.74

*Requires high demand on reformer.

**Includes steam production for reformer.

Table 2.2-5

Projected Energy Consumption by Five Industries
(10^{12} BTU)

INDUSTRY \ YEAR	1974	1980	1985	1990	1995	2000
PAPER						
Coal	209.3	243.9	308.2	364.0	424.8	495.9
Oil	585.6	682.3	862.4	1018.5	1188.9	1387.8
Gas	418.7	487.8	616.4	728.2	850.2	992.4
Electricity	136.0	158.5	200.1	236.5	276.0	322.1
Other	874.2	1018.4	1287.3	1520.9	1775.2	2072.0
	2223.8	2591.4	3274.4	3868.1	4515.1	5270.2
CHEMICAL						
Coal	342.8	482.2	655.3	875.2	1102.6	1390.9
Oil	2100.7	2866.8	3915.4	5211.1	6574.5	8295.6
Gas	2154.5	3030.8	4124.9	5503.4	6936.6	8751.0
Electricity	436.9	615.2	847.5	1121.1	1418.3	1790.2
Other	176.1	336.5	458.0	611.1	770.1	971.5
	5211.0	7331.5	10001.2	13322.1	16802.3	21199.3
PET. REF.						
Coal	5.3	6.6	7.5	8.4	9.3	10.2
Oil	745.9	917.7	1038.4	1158.2	1280.7	1416.0
Gas	2235.3	2749.8	3111.8	3471.3	3838.3	4243.6
Electricity	83.7	101.1	116.5	129.9	143.7	159.6
Other	3.0	3.7	4.1	4.6	5.1	5.6
	3073.2	3778.9	4278.3	4772.5	5277.1	5834.8
STONE						
Coal	259.8	335.8	387.2	448.7	514.0	588.9
Oil	125.7	162.5	187.2	216.9	248.5	284.7
Gas	708.0	914.7	1054.5	1221.9	1400.0	1604.0
Electricity	163.7	211.3	243.6	282.1	323.6	370.6
Other	44.0	56.8	65.5	75.9	87.0	99.6
	1301.3	1681.0	1938.0	2245.5	2573.1	2947.9
STEEL						
Coal	2419.8	2332.0	2742.8	3103.4	3424.7	3779.4
Oil	264.4	254.9	299.7	339.1	374.4	412.9
Gas	651.5	628.2	739.0	836.0	922.9	1018.2
Electricity	172.0	165.5	194.7	220.4	243.1	268.2
Other	-87.2	-84.2	-99.1	-112.1	-123.7	-136.5
	3420.5	3296.4	3877.2	4386.8	4841.4	5342.2
TOTAL FIVE INDUSTRIES						
Coal	3237.0	3400.5	4101.0	4799.7	5475.4	6265.3
Oil	3822.3	4884.2	6303.1	7943.8	9667.0	11797.0
Gas	6168.0	7811.3	9646.6	11760.8	13948.0	16609.2
Electricity	992.3	1251.6	1602.4	1990.0	2404.7	2910.7
Other	1010.2	1331.7	1715.8	2100.4	2513.7	3012.2
TOTAL FUELS	15229.8	18679.3	23369.1	28595.0	34009.0	40594.4

Source: Reference 6

Table 2.2-6

Demand Projections for Industrial Fossil Energy Requirements in 247 Utility Service Areas

		1980	1990	2000	2010	2020
Energy (E6 BTU)	Less than 500°F	7.716E9	1.084E10	1.568E10	2.249E10	3.229E10
	500 to 1000	5.957E9	8.296E9	1.193E10	1.701E10	2.437E10
	1000 to 1700	5.322E8	7.242E8	1.038E9	1.477E9	2.113E9
	Less than 1700°F	1.421E10	1.986E10	2.865E10	4.098E10	5.877E10
	Steam	8.198E9	1.145E10	1.649E10	2.354E10	3.372E10
	Direct Heat	9.682E9	1.324E10	1.880E10	2.647E10	3.748E10

		Number	Percent
Plant	Less than 2500 hrs	275871	82.3
	2500 to 6000	53605	16.0
	More than 6000	5870	1.8

Thermal Rating		Number	Percent	Number Less than 3000 hrs
Less than .5	Million	255700	76.2	247580
.5 to 1	Watts	30424	9.1	23696
1 to 2	Thermal	21068	6.3	13116
2 to 5		15080	4.5	7935
5 to 10		5585	1.7	2936
10 to 20		3447	1.0	1460
20 to 35		1493	.4	527
35 to 50		708	.2	243
50 to 100		1062	.3	204
More than 100		779	.2	17
Total		335346		297714

1980 Fuel (E6 BTU)	Oil	3.853E9
	Coal	3.699E9
	Gas	9.277E9
	Other	1.051E9

Source: Reference 33

plants and their number of hours of operation. Note in the table that oil and gas currently account for nealy 80% of the total process heat energy input. The table shows that approximately 99% of the total number of plants require less than 20 MWt of input process heat, with 85% of the total number requiring less than 1 MWt. However, when estimates are made regarding the integrated thermal input, it is clear that the relatively small number of plants requiring 20 MWt or greater process heat input accounts for in excess of 50% of the total process heat market. It should also be noted that approximately 82% of all plants operate for only one shift, six days a week, while only 2% operate more than 2 shifts, seven days a week. As might be expected, the table indicates that the larger, more capital-intensive plants tend to be operated at higher capacity factors.

In summary, the process heat market appears to be characterized in terms of two major market segments. The first is a market segment comprising a large number of small, widely disbursed, single-shift operations. To service this market, a highly versatile means of energy storage and distribution is essential. For the existing facilities, a synfuels technology may provide the optimum solution for displacing currently used oil and gas resources. For new facilities, the HTGR may provide a basis for the development of new industrial parks. Since the facilities in question operate at low capacity factors, energy storage capability would be a prime consideration to allow baseloading of the nuclear facility.

The second major market segment is a small number of large three-shift operations. Because of the large unit sizes and high capacity factors associated with these operations, central station cogeneration may be a viable energy option for either current or new facilities. The ability to access this market segment would also be enhanced by the capability for energy storage and distribution.

Summary

Even with conservative assumptions, there appear to be large potential markets for the HTGR in both the electricity generation and the process heat production markets after the year 2000. Based on the data presented in this section, the market factor of Forecasted Energy Demand is concluded to be positive for all of the HTGR systems. The remainder of this report will evaluate the remaining market factors identified in Section 2.1 with overall market assessments of the HTGR-SC, HTGR-GT, and HTGR-R presented in Sections 5.3, 6.3, and 7.3 respectively.

3.0 UTILITY SYSTEMS ANALYSIS

Assessments have been conducted in the past involving the HTGR's ability to provide national benefits, but the advantages or disadvantages of this technology relative to utility systems have heretofore not been widely addressed. Through the utilization of utility systems models, systems methodology, and generation planning techniques, the market penetrability of the HTGR can be analyzed from the perspective of the electric utility industry.

GCRA performed the analyses in this section in order to better understand what impacts, if any, the HTGR might have on utility system performance and economics. By these efforts, it was hoped to gain insight into the areas of HTGR design and performance which will yield demonstrable benefits to the utility/user and to quantify these benefits by determining their relative effects on the utility system economic characteristics.

An area which requires further analysis is the significant effect that energy storage systems can have on the economic characteristics of the utility system. A logical extension of these studies will be to model a sensible heat storage system or a thermochemical storage system used in conjunction with the HTGR and determine the effects on the system economic performance.

3.1 SYSTEMS ANALYSIS - APPROACH

Introduction - In 1976, the Electric Power Research Institute (EPRI) initiated a project to develop flexible and representative utility systems for use in performing utility planning studies. Sufficient data were to be developed to allow synthesis of such utility systems to be broadly representative of the systems of EPRI member utilities throughout the United States. This project culminated in February 1977 with the publication of "Synthetic Electric Utility Systems for Evaluating Advanced Technologies" (Reference 20).

These models are being used by EPRI to assist in the challenging task of establishing research and development priorities. Specifically, EPRI is using this approach of adapting utility system generation-planning techniques for evaluating future technology power system options, as well as the currently available options. The result is a consistent economic analysis that has the following capabilities (Reference 21):

- Defines the most appropriate role of each technology in the generation mix.
- Yields the market penetration potential for each technology.
- Shows the degree by which some technologies must improve to become economic.
- Estimates the present-value savings and cost-benefit ratios that may be achieved if successful R&D results are put into practice.

When analyzing alternative technologies, it is desirable to maintain overall consistency of methods and assumptions. To this end, EPRI developed the "Technical Assessment Guide" (TAG) (Reference 22), which was published in June 1978. The TAG contains certain assumptions, data, and methodology that are used by EPRI as a basis for assessing the value of research and development programs.

System Definition and Selection - The data contained in the TAG are presented on a national basis or on regional bases where regional differences are considered significant. These regions are depicted in Figure 3.1-1.

In 1968, the National Electric Reliability Council (NERC) was formed "to augment the reliability and adequacy of bulk power supply in the electric utility systems of North America" (Reference 23). NERC consists of nine regional reliability councils and encompasses essentially all of the power systems of the United States and the Canadian systems in Ontario, British Columbia, Manitoba, and New Brunswick. Because of the objectives of this Assessment, the review of the NERC systems focused on the contiguous U.S. regions only. These regions are depicted in Figure 3.1-2. A comparison of Figures 3.1-1 and 3.1-2 reveals reasonable correspondence between the regions utilized by EPRI and NERC.

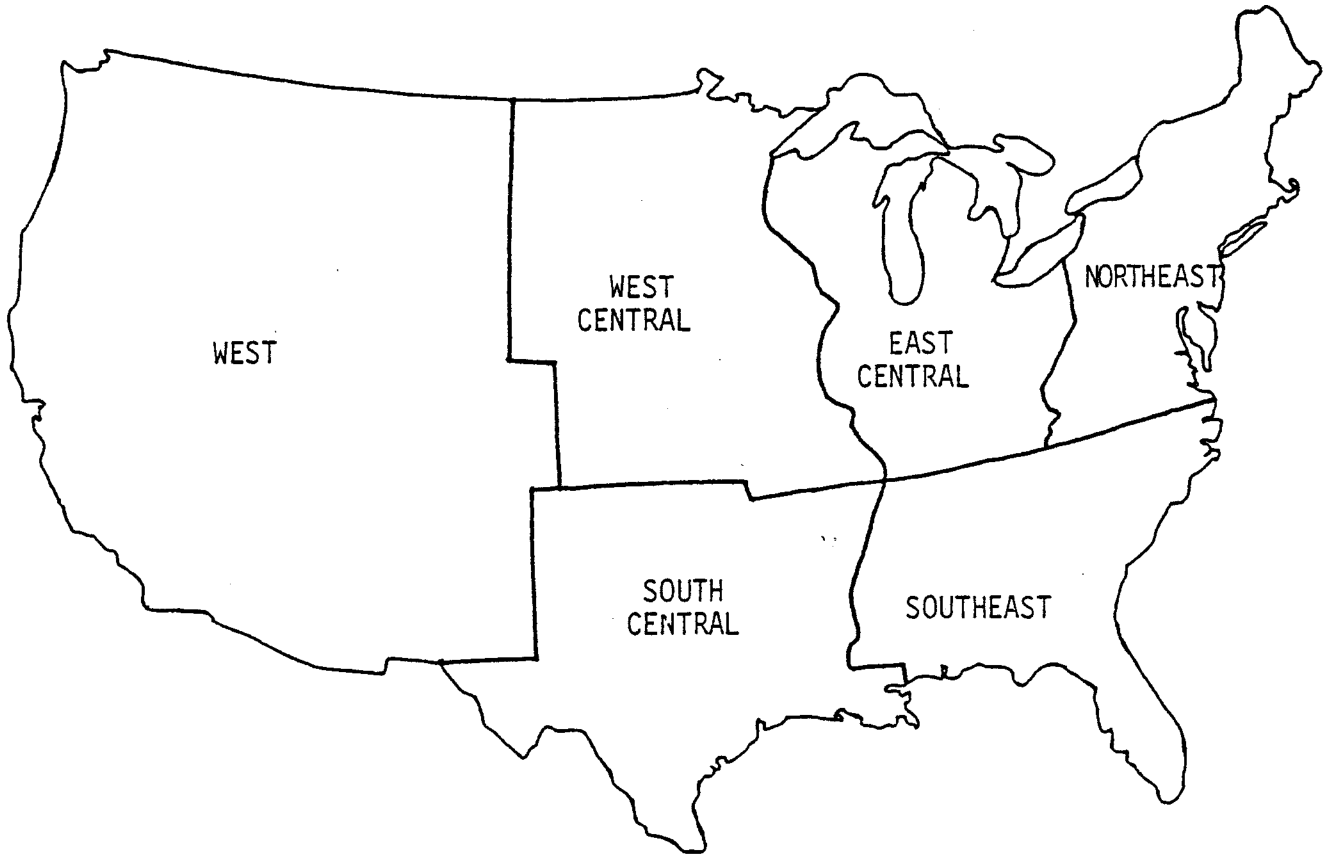
The EPRI synthetic utility systems are described in detail in Reference 10. The synthetic systems include data for the generating system characteristics, transmission network characteristics, and load characteristics. In Appendix A, Table A.1-1 shows the major characteristics of the EPRI synthetic systems in 1985. The EPRI synthetic systems also exist as scaled-down systems which are reasonably representative of single utility systems within the particular region. For this study, a scaled-down system was used; therefore, the results are representative of a large single utility in the region. Table A.1-2 shows the major characteristics of the study region in 1985 based on data obtained from Reference 23.

Based on the recommended applications of the synthetic systems in the TAG and a comparison of system characteristics shown in Tables A.1-1 and A.1-2, the Northeast regional utility system modeled for this study was derived from the "D" EPRI synthetic system. This synthetic system, and its associated data, is believed to be a reasonable representation of the corresponding regional utility system. It may not be, and is not intended to be, representative of any individual utility. Indeed, there is often more variation among utilities within a region than among regions as a whole.

System Load Growth - Reference 23 summarizes the forecast peak loads for each NERC region for the years 1978 to 1987. Based on these NERC data, it was felt appropriate to use growth rates as shown in the table below:

Figure 3.1-1

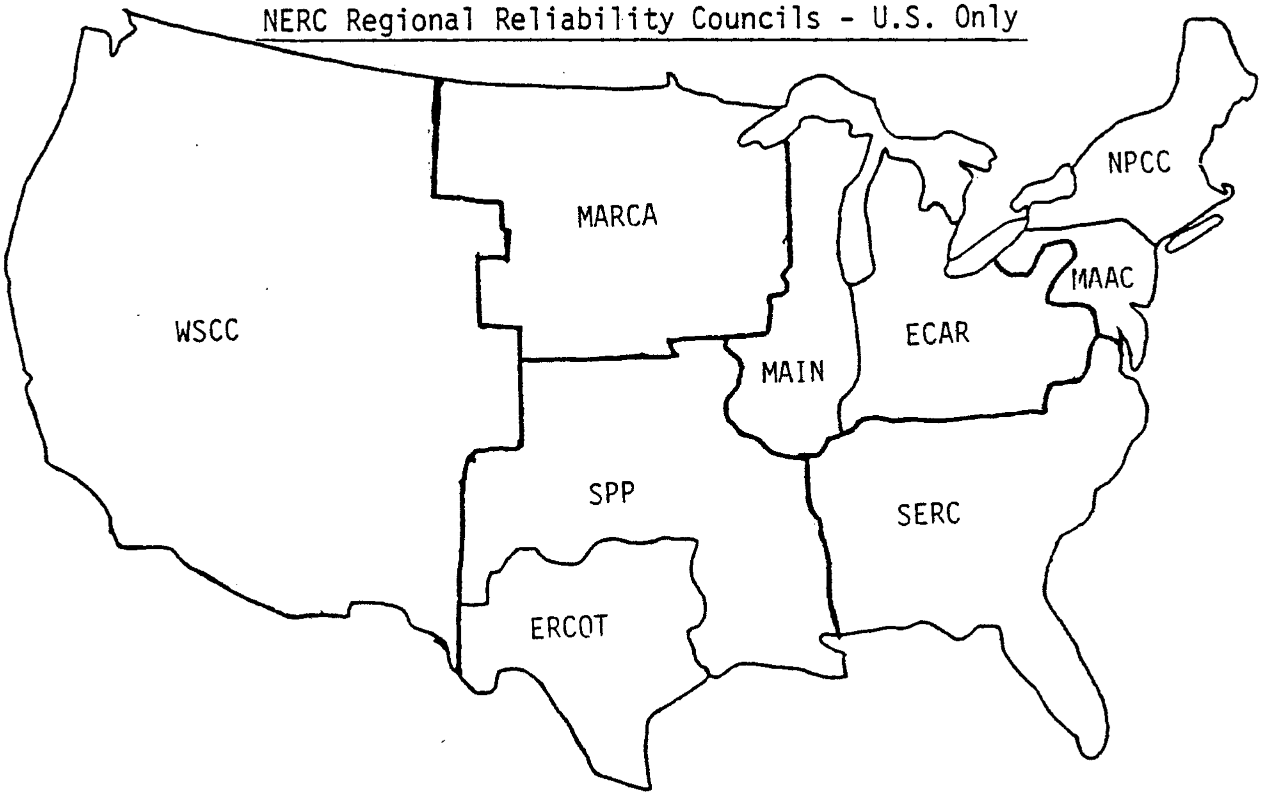
EPRI Data Regions



(EPRI TAG Fig. I-1)

Figure 3.1-2

NERC Regional Reliability Councils - U.S. Only



(NERC 9th Annual Review Inside Cover)

Table 3.1-3

Regional Loads and Growth Rates

	U.S. Regional System Northeast
Regional Reliability Council(s)	MAAC, NPCC
Peak Load - MW 1978	68,398
1983	82,104
1987	94,376
Growth Rate - % 1978-83	3.71
1983-87	3.54
Study Growth Rate - % 1985-1989	3.50
1990-2020	3.50

3.2 SYSTEMS ANALYSIS - METHODOLOGY

3.2.1 Generation Planning Methods

Traditionally, generation expansion planning analyses involve the following three major steps:

1. System reliability evaluation.

2. Production cost evaluation.

3. Investment cost evaluation.

The first step is the determination of types of new generation to be available and their sizes, a measurement of their performance against a system reliability standard, and a determination of necessary installed capacity for any given year. The production and capital investment costs of the various alternatives are calculated and total annual system costs are determined. The total costs for each alternative are frequently expressed in terms of either levelized annual revenue requirements or present worth of all future revenue requirements (PWRR). When using the revenue requirement method, the optimum plan will be the one which minimizes PWRR.

For short-range studies, or studies related to specific situations, the selection of generation alternatives is a manual process. Detailed computer programs are employed to calculate system reliability and production costs, and to evaluate the effects of the required investment on corporate finances. For long-range optimum expansion studies such as this, the detailed analyses described above can become prohibitively time-consuming and expensive. For this type of study, several generation expansion computer programs have been developed which combine all of the planning steps into a single program package using simplified calculation methods. One such program is General

Electric Company's Optimized Generation Planning (OGP) program. OGP was chosen for use in this study because of its high level of utility acceptance and because the EPRI synthetic utility system data bases have been used previously with OGP and were readily available.

The following sections describe in more detail the three steps of generation expansion planning previously outlined.

System Reliability Evaluation - The purpose of reliability evaluation is to determine the amount of generation that must be installed on a system in order to satisfy a specified reliability criterion for meeting the load demand. The reliability criterion is usually expressed as a loss-of-load probability (LOLP), in terms of expected days per year of insufficient generating capacity to meet the load. A capacity outage probability model is developed from the ratings and forced outage rates of the generating units. The model is modified as units are added, retired, down for maintenance, or returned from maintenance. A load distribution model is developed from the daily or weekly peak loads. LOLP is obtained by convolving the capacity and load models. If the LOLP for the system does not meet the specified criterion, additional generating capacity must be added to the system. Different types of generating unit additions will generally have different effects on system reliability due to variations in size and forced outage rate. When comparing alternatives, it is important that the resulting systems have equal reliability.

Production Cost Evaluation - Production cost computer programs simulate the operation of a power system. The generating units are represented by their heat rates at various load levels, their fuel and O&M costs, and their forced and planned outage rates. Loads may be represented either by load distribution curves or hour-by-hour load patterns. Hydro and energy storage units are typically dispatched first. The amount of energy produced (or consumed for charging) is reflected in the load model by reducing (or increasing) the loads. Thermal units are then dispatched on an equal incremental cost basis to meet the remaining loads. Various operating constraints may be introduced such as spinning reserve, unit commitment, minimum downtime requirements, and environmental effects. Most production cost programs also have provisions for simulating sales and purchases of energy from outside systems. The methods of modeling outage rates, operating constraints, and energy interchange vary from program to program.

Investment Cost Calculation - The investment cost for a new unit is expressed as a levelized annual fixed charge calculated by applying a fixed charge rate to the unit's capital cost at the time of installation. Financial simulation programs, or "corporate models," are available to determine the financial impact of a generating unit addition. Financing, rate adjustments, and accounting procedures are simulated. The resulting effects on important quantities such as cash flow, net income, earnings per share, and the various corporate financial statements may influence the selection of the generation plan.

3.2.2 Optimized Generation Planning (OGP) Program

The preceding steps are integrated by OGP in the logic depicted on Figure 3.2-1 to automatically develop an optimum generation plan.

A brief description of the program logic follows. For a more detailed discussion, please consult the "Descriptive Handbook for the Optimized Generation Planning Program," General Electric Company, January 1979.

1. The user supplies input data describing:

   a. The operating costs and characteristics of all existing and committed generating units and the expansion candidate generating unit types.

   b. Load data describing the daily and monthly load patterns, annual MW peaks, and forecast load growth.

   c. Study factors such as escalation rates, reliability criteria, and minimum acceptable rate of return.

2. For each year, the program will develop a list of generation addition alternatives from the list of specified candidate expansion units. Each alternative is tested for its ability to meet the specified LOLP system reliability criterion. Using a "look ahead" option, mature unit outage rates are used for these calculations to anticipate future conditions.

3. System production costs are calculated for each alternative. Using a "look-ahead" option, levelized annual fuel and O&M costs and mature unit outage rates are used for these calculations to anticipate future conditions which may affect generating unit operation.

4. Levelized annual capital investment costs are calculated for each alternative.

5. Total production plus investment cost is determined for each alternative. The alternative with the lowest total cost is selected as the "optimum" addition to the system.

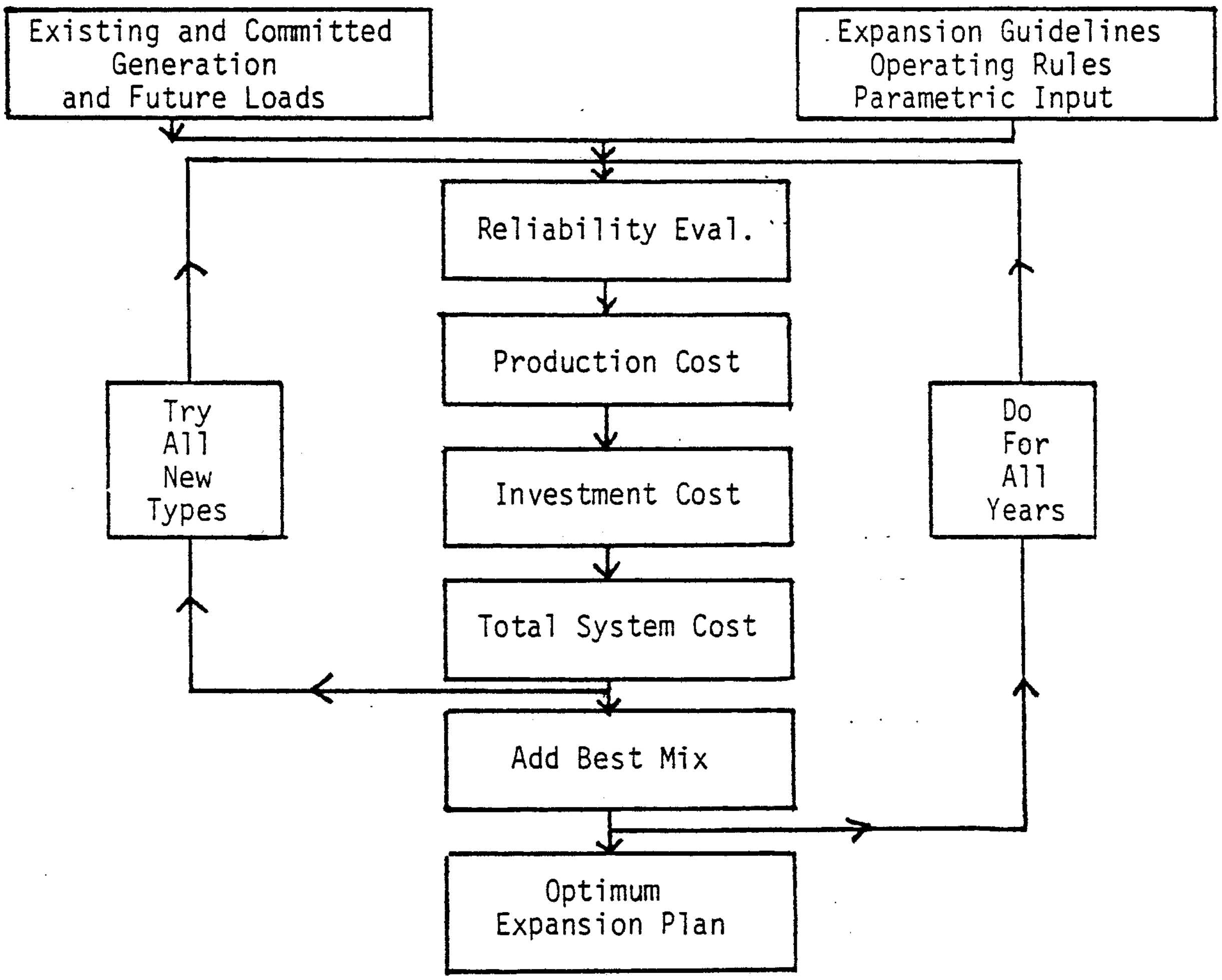
6. System reliability is rechecked for the selected alternative using current year outage rates.

7. System production costs for the selected alternative are recalculated using current year costs and outage rates.

8. The program repeats steps 2-7 for each succeeding year in the study.

Figure 3.2-1

The Optimized Generation Planning Program Conceptual Flow Chart



Source: Descriptive Pamphlet for the Optimized Generation Planning Program, General Electric Company.

3.3 SYSTEMS ANALYSIS - RESULTS

3.3.1 Overview

Many types of generating units may be considered viable candidates for utility systems analyses. It is impractical to attempt to consider all of the numerous possibilities in developing a long-range system expansion. The OGP program itself is limited to consideration of six types of thermal capacity and three types of energy storage capacity at any one time. It was not the intent of this Assessment to evaluate all of the possible competing technologies. Immediate interest was in evaluating the HTGR in the context of utility generation. Given the objective and the constraints, the expansion unit candidates shown in Table 3.3-1 were selected for the study.

1985-2000 Expansion - The EPRI synthetic system models represent 1985 systems. Since the HTGR is not expected to become commercially available until the year 2000, it was first necessary to expand the synthetic system to this future date. This was done by initially selecting additional generation alternatives which were expected to become commercially available during this period. A combination of assumptions and OGP verification led to the year 2000 utility system which is described in Section 3.3.2. This system as it appeared in the beginning of the year 2000 was input as the reference system for analyzing the HTGR during the 2000-2020 time period.

2000-2020 Expansion - Three base case optimum mix scenarios were developed for the Northeast region:

1. No nuclear unit additions allowed.

2. LWR nuclear unit additions allowed.

3. LWR and HTGR nuclear unit additions allowed.

The first scenario, with no nuclear additions after the year 2000, establishes a base line to evaluate the economic attractiveness of nuclear power in general. The second scenario, allowing LWR type nuclear units in the optimum mix, establishes a base line to evaluate the attractiveness of the HTGR in particular as an alternative nuclear power source. The third scenario, when compared with the first two, provides an estimate of the potential impact of the HTGR. OGP was utilized to develop optimum utility systems for each of these scenarios for the 20-year period. The resulting generation mixes are described in Section 3.3.2.

Beyond the base case evaluations, key variables affecting the HTGR's penetrability into utility systems were studied to investigate the relationship of these variables and their relative impact on the

Table 3.3-1

Expansion Unit Candidates

Unit Type	Size (1)	Available for Commercial Service
Nuclear:		
LWR	1200 MW	Current
HTGR	1200 MW	2000
Coal:		
Conventional w/FGD (2)	600 MW	Current
	1000 MW	Current
	1200 MW	Current
Atmospheric Fluidized-Bed	1000 MW	1990
	1200 MW	2000
Gas Turbine:		
Current Technology	75 MW	Current
Advanced Technology	100 MW	1987
Combined Cycle:		
Current Technology	250 MW	Current
Advanced Technology	285 MW	1989
Energy Storage (Batteries)	100 MW	1990

Notes: (1) The advanced technology units will replace the current technology units as expansion candidates in the year they become commercially available.

(2) FGD = Flue Gas Desulfurization

application of the HTGR. These sensitivity analyses are discussed in Section 3.3.3.

3.3.2 Utility Base Case Analysis

The Northeast region base case characteristics include base-load, intermediate, peaking and storage type electric generation. The abbreviations of the units used in this study are shown in Table 3.3-2. The two nuclear alternatives addressed--the LWR and HTGR--have, for this study, characteristics as shown in Table 3.3-3. Fuel costs and the other characteristics of the expansion candidates are given in Appendix A sections A.1 and A.2.

All HTGR costs were assumed to be at parity with the LWR except for the fuel costs. This was done in order to provide a parametric evaluation of the effect of variations in each of the HTGR cost factors, i.e., capital, fuel, O&M, forced outage rates, and planned outage rates. Fuel cost was selected as the distinguishing cost factor because fuel costs for the HTGR have been well developed and are based on the physical characteristics of the reactor as well as actual manufacturing experience. At the time this study was initiated, the HTGR Fuel Cycle Cost Study (Reference 24) had not yet been completed; therefore, an HTGR fuel cost differential of 8% above the reference LWR fuel cost was used as a reference. This 8% differential corresponds to the differential between the mean of the HTGR-SC and GT fuel costs with the HEU(93%)/Th U recycle fuel cycle, and the LWR with the Pu and U recycle fuel cycle. These fuel cycles were selected because they are the most economical for both the HTGR and the LWR. A further discussion of fuel cycle costs is presented in Section 4.5.

The capital costs were assumed at parity for the base cases as explained above. Actual expected capital costs for the various HTGR systems are presented in Sections 5.2, 6.2, and 7.2. The sensitivity analyses in Section 3.3.3 describe the effects of varying the capital costs so that the capital cost estimates in the above sections can be related to the results of this systems analysis.

Coal Base Case - The initial Northeast situation addressed was that there was no nuclear option available after the turn of the century. Beginning in the year 2000, the Northeast region had the generation characteristics as shown in Table 3.3-4. This situation expanded to the year 2020 had the generation characteristics shown also in Table 3.3-4 with the generation type deployment pattern shown in Figure 3.3-5. The change in generation mix as a percentage by year can be found in Figure 3.3-6. Nuclear capacity had dropped from 40% to around 15% of the total system mix, as none were available for purchase and two units were retired. (While the possibility of LWR end-of-life requalification exists, this study assumed conventional retirement.) This 15% nuclear capacity produced 22% of the power in the final year of the study. Similar margins exist today throughout the U.S. because of the advantage of nuclear generation costs. The coal mix more than doubled to 57% in the 20 years of this study. The system added fourteen 1200 MWe atmospheric fluidized bed (AFB) units.

Table 3.3-2

Generation Type Abbreviations

BATT	-	Battery
C/AFB	-	Coal/Atmospheric Fluidized Bed
CC	-	Combined Cycle
C/O	-	Pre-1985 Coal and/or Oil
C/600	-	Pre-1985 Coal
C/1000	-	Coal/1000 MWe w/Flue Gas Desulfurization
GT	-	Gas Turbine
H	-	Conventional Hydroelectric
HTGR	-	High Temperature Gas-Cooled Reactor
LWR	-	Light Water Reactor

Table 3.3-3

Nuclear System Unit Input Data (1980 $)

	Size (MWe)	Efficiency %	Capital Cost(1) ($/KWe)	Fuel Cost(2) ($/MBtu)	O&M Cost Fixed ($/KWe)	O&M Cost Variable ($/MWhr)
Northeast						
LWR	1200	33.8	1045	.682	10.10	1.50
HTGR	1200	39.6	1045	.736	10.10	1.50

Notes: (1) Includes contingencies, owner's costs, and AFDC.

(2) Based on full recycle fuel cycles.

Table 3.3-4

Northeast - No Nuclear Option

		Beginning Year: 2000	System Capacity: 17855 MW	End Year: 2019	System Capacity: 32950 MW
		MW	% Mix	MW	% Mix
LWR	=	7200	40.3	4800	14.6
Coal					
1000	=	1000	5.6	1000	3.3
AFB	=	1000	5.6	17800	54.0
Pre-1985	=	3000	16.8	0	0
Subtotal	=	5000	28.0	18800	57.3
Oil	=	2200	12.3	800	2.4
Gas Turbine	=	1750	9.8	3700	11.2
Combined Cycle	=	1105	6.2	2850	8.6
Battery	=	600	3.4	2000	6.1
Total		17855	100.0	32950	100.0

Figure 3.3-5

Generation Deployment Pattern 2000 to 2020

Northeast - No Nuclear Option

GENERATION SYSTEM

	LWR	HTGR	G.T.	C.C.	C-1000	C-AFB	TYPES
TYPE	1	2	3	4	5	6	7-10

****

YR	Y E A R L Y		M W		A D D I T I O N S			TOTAL CAPAB. + TIES
**	*******	*******	*******	*******	*******	*******	*****	******
0			300*				400*	18155
1			7X 100	1X 285				18740
2			1X 100	2X 285			200	19210
3						1X1200		20010
4			2X 100	3X 285				20865
5						1X1200		21665
6			1X 100				200	21965
7						1X1200		22965
8			7X 100					23265
9						1X1200		24265
10			5X 100	1X 285				24850
11			3X 100			1X1200		25750
12						1X1200		26900
13						2X1200		27700
14							500	28200
15			1X 100			1X1200	100	29000
16						1X1200		29950
17						2X1200		31150
18						1X1200		31750
19						1X1200		32950

****

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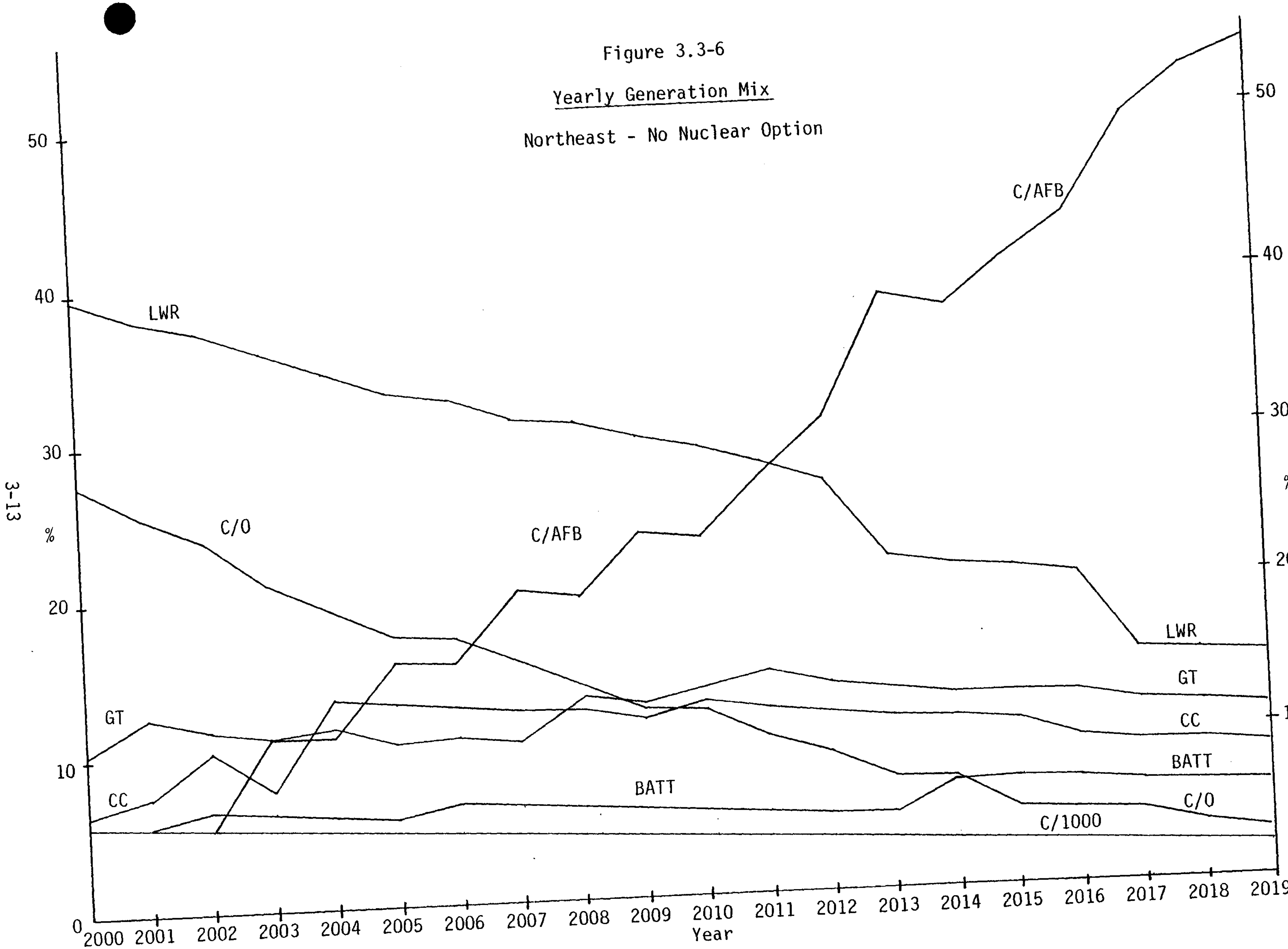
Figure 3.3-6

Yearly Generation Mix

Northeast - No Nuclear Option



The advantage in capital cost of the AFB over the conventional coal units overshadowed the expected operation and maintenance disadvantages as the utility consistently chose the former over the latter. As older oil and coal units were retired, they were replaced by more economic baseload coal, intermediate combined cycle units, and peaking combustion turbine units. Energy storage increased slightly and contributed approximately 6% of the total mix.

LWR Base Case - The scenario where the LWR was a continuing and unconstrained option in the Northeast was evaluated. This situation expanded to the year 2020 had the generation characteristics shown in Table 3.3-7 with the generation type deployment pattern shown in Figure 3.3-8. The change in generation mix as a percentage by year can be found in Figure 3.3-9. Installed nuclear capacity increased from 40% to 70% of total mix, but as depicted on Figure 3.3-9 the nuclear percentage is reaching an asymptote. It would appear that this utility would limit itself to approximately 70% nuclear capacity.

The coal mix was reduced from 28% to about 6%, and seven oil units were retired as fifteen 1200 MWe LWRs were added and two were retired during the 20-year study period. Gas turbine mix was changed downward slightly from 10% to 8%, and the mix of combined cycle units was reduced from 6% to 2.6%. Energy storage played a larger role in the LWR base case than in the coal base case due primarily to the economic advantages related to nuclear "pumping" costs. Energy storage increased from 3.4% to nearly 11% of total generation mix by the year 2020.

In this scenario, nuclear units were added in favor of other baseload coal units despite a capital cost penalty of nearly 30%. The fuel cost savings was, as it is today, the major factor in the choice of nuclear over coal. In addition, the nuclear units were consistently run at higher capacity factors than the coal units. This was again because of the fuel cost savings associated with the nuclear units. Several older coal units were generally run at higher capacity factors than the newer coal units until they were retired. This was attributed primarily to lower outage rates and lower maintenance costs.

HTGR Base Case - The scenario in the Northeast where the LWR was a continuing option as well as the HTGR becoming an available option in the year 2000 had the year 2020 generation characteristics as shown in Table 3.3-10 with the generation type deployment pattern shown in Figure 3.3-11. The change in generation mix as a percentage by year can be found in Figure 3.3-12. Total nuclear capacity increased from 40% to 70%, but the LWR fraction had dropped to 14% by the beginning of the year 2020, as all nuclear additions were of the HTGR type. Total nuclear capacity reached an asymptote of around 70%, and retired baseload units were likely to be replaced by the HTGR. The HTGR was added in favor of the LWR in the Northeast due to the HTGR's lower fuel costs which result from its advantage in heat rate. Utility system reserve margins averaged 28.4% over the 20-year study period.

Table 3.3-7

Northeast - LWR Option

		Beginning Year: 2000 System Capacity: 17855 MW		End Year: 2019 System Capacity: 34055 MW	
		MW	% Mix	MW	% Mix
LWR	=	7200	40.3	2400	70.5
Coal					
1000	=	1000	5.6	1000	2.9
AFB	=	1000	5.6	1000	2.9
Pre-1985	=	3000	16.8	0	0
Subtotal	=	5000	28.0	2000	5.8
Oil	=	2200	12.3	800	2.3
Gas Turbine	=	1750	9.8	2700	7.9
Combined Cycle	=	1105	6.2	855	2.5
Battery	=	600	3.4	3700	10.9
Total		17855	100.0	34055	100.0

Figure 3.3-8

Generation Deployment Pattern 2000 to 2020

Northeast - LWR Option

GENERATION SYSTEM

	LWR	C-600	G.T.	C.C.	C-1000	C-AFB	TYPES
TYPE	1	2	3	4	5	6	7-10

YEARLY MW ADDITIONS

YR								TOTAL CAPAB. + TIES
**	*******	*******	*******	*******	*******	*******	*****	******
0			300*				400*	18155
1	1X1200							18955
2							700	19255
3	1X1200		1X 100					20155
4	1X1200							21155
5			6X 100				100	21455
6	1X1200							22655
7							300	22755
8	1X1200		1X 100					23655
9	1X1200							24655
10			1X 100				700	25255
11	1X1200		2X 100				100	26155
12	1X1200							27305
13	2X1200		1X 100					28205
14			1X 100				700	29005
15	1X1200		2X 100				100	29905
16	1X1200							30855
17	2X1200							32055
18	1X1200		2X 100					32855
19	1X1200							34055

Figure 3.3-9

Yearly Generation Mix

Northeast - LWR Option

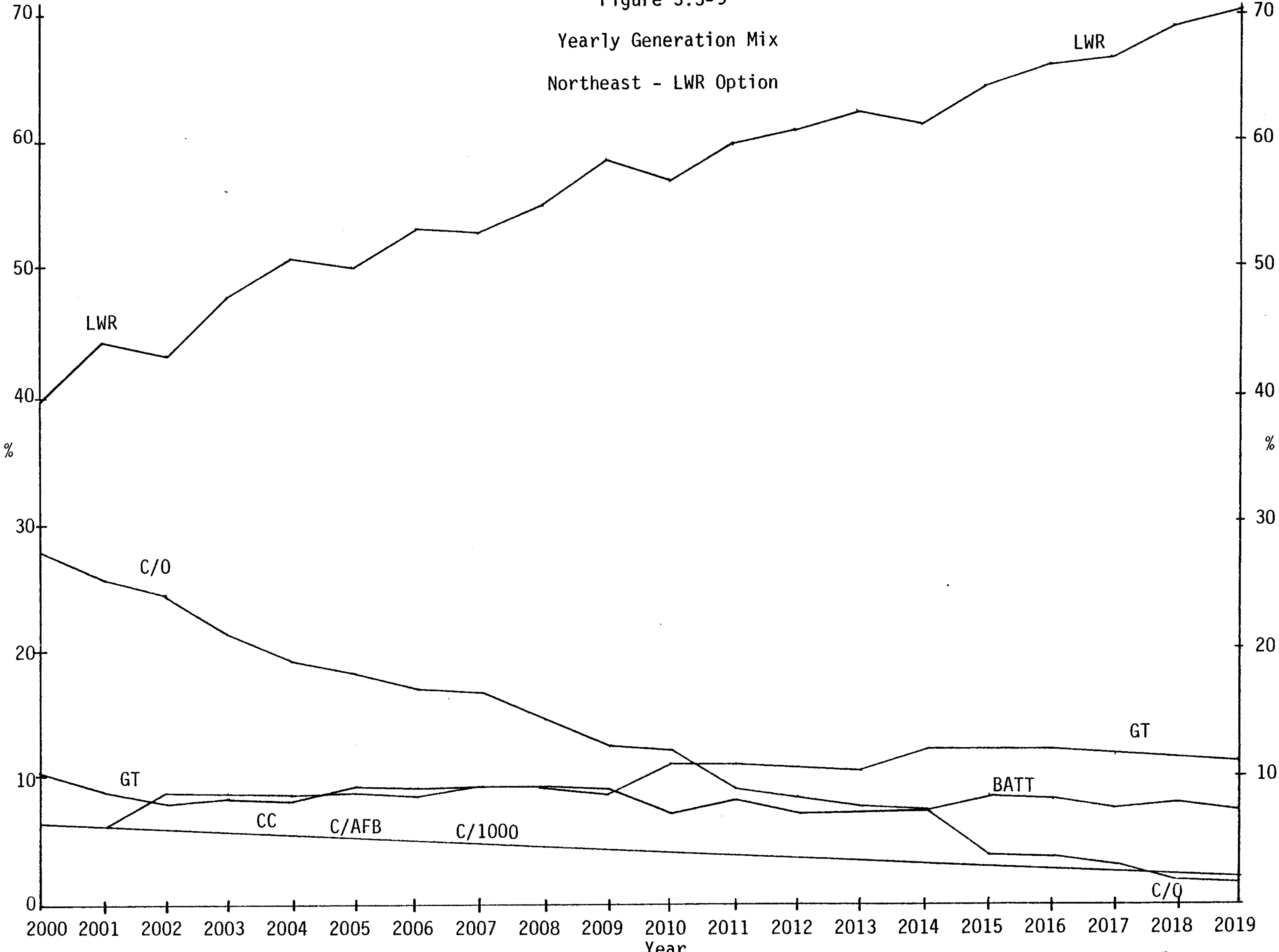


Table 3.3-10

Northeast - LWR and HTGR Option

		Beginning Year: 2000 System Capacity: 17855 MW		End Year: 2019 System Capacity: 34055 MW	
		MW	% Mix	MW	% Mix
LWR	=	7200	40.3	4800	14.1
HTGR	=	0	0	19200	56.4
Coal					
1000	=	1000	5.6	1000	2.9
AFB	=	1000	5.6	1000	2.9
Pre-1985	=	3000	16.8	0	0
Subtotal	=	5000	28.0	2000	5.8
Oil	=	2200	12.3	800	2.3
Gas Turbine	=	1750	9.8	2700	7.9
Combined Cycle	=	1105	6.2	855	2.5
Battery	=	600	3.4	3700	10.9
Total		17855	100.0	34055	100.0

Figure 3.3-11

Generation Deployment Pattern 2000 to 2020

Northeast - LWR and HTGR Option

GENERATION SYSTEM	LWR	HTGR	G.T.	C.C.	C-1000	C-AFB	TYPES
TYPE	1	2	3	4	5	6	7-10

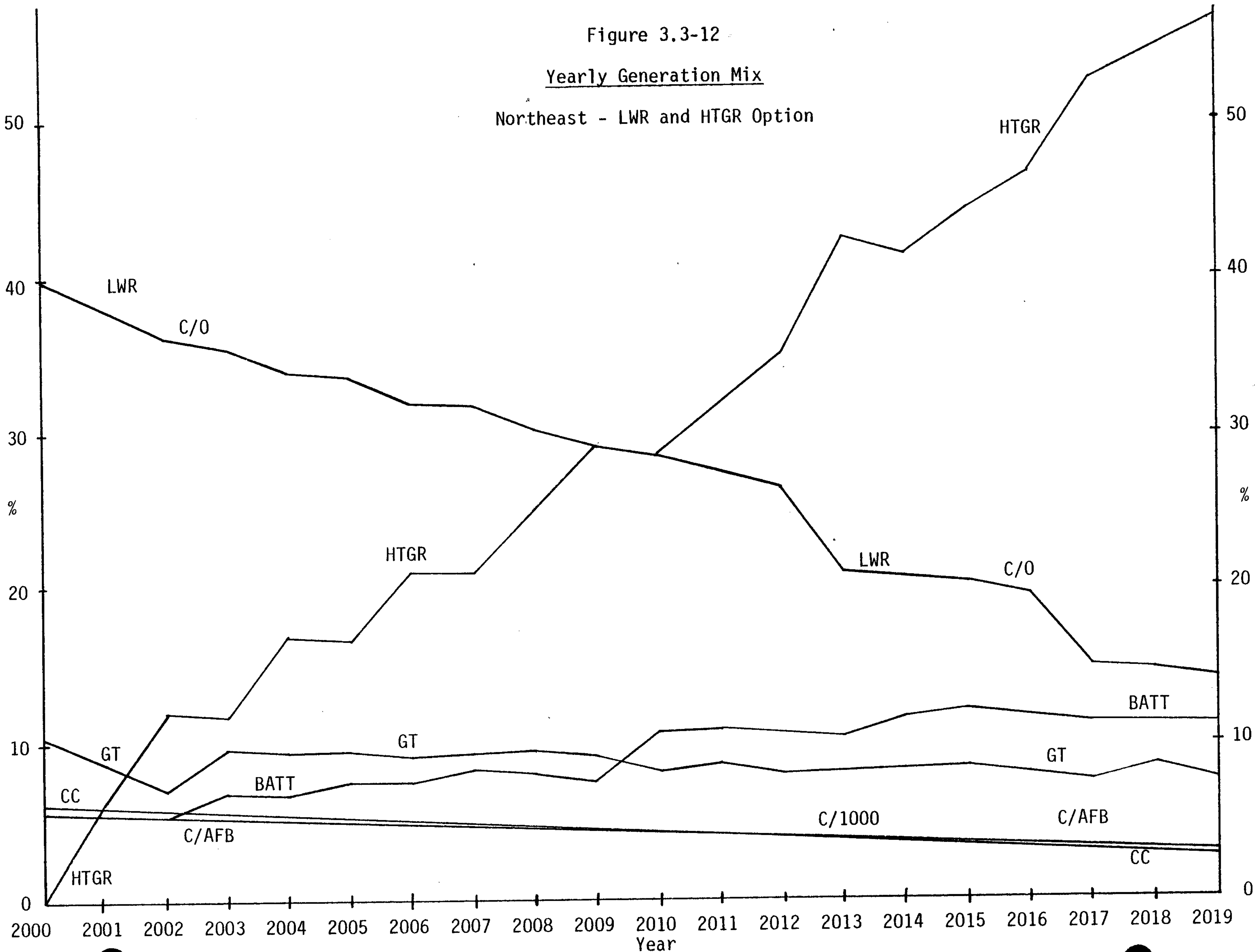
****

YR	Y E A R L Y		M W		A D D I T I O N S			TOTAL CAPAB. + TIES
**	*******	*******	*******	*******	*******	*******	*****	******
0			300*				400*	18155
1		1X1200						18955
2		1X1200						19755
3			5X 100				300	20155
4		1X1200						21155
5			3X 100				300	21355
6		1X1200						22555
7			1X 100				300	22755
8		1X1200	1X 100					23655
9		1X1200						24655
10							800	25255
11		1X1200	2X 100				100	26155
12		1X1200						27305
13		2X1200	1X 100					28205
14			1X 100				600	28905
15		1X1200	1X 100				200	29805
16		1X1200						30755
17		2X1200						31955
18		1X1200	2X 100				100	32855
19		1X1200						34055

Figure 3.3-12

Yearly Generation Mix

Northeast - LWR and HTGR Option



The coal mix was reduced to 6% down from 25%, and seven oil units were retired as sixteen 1200 MWe HTGRs were added and two LWRs were retired during this 20-year study period.

In this scenario, nuclear units were consistently run at higher capacity factors than coal units. After several years, maturing HTGRs were run at slightly higher capacity factors than LWRs. HTGRs were generally run between 60% and 70% capacity factors and averaged 69% over the study period despite the penalty associated with the immaturity of new plant additions. LWRs were also generally run between 60% and 70% capacity factors and averaged 62.3% over the study period.

Baseline Comparisons

The baseline cases are discussed comparatively in this section. Factors such as economics and fuel consumption are analyzed relative first to the utility study region and second to the national environment as forecasted by the Electric Power Research Institute.

Economics - The cost values discussed here are cumulative for the years 2000 through 2020 and are present worth 1980 dollars, end-year adjusted to properly account for plant costs beyond the year 2020. The process of end-year adjustment is described in Appendix A, Section A.3.

In the coal base case, the Northeast region spent nearly \$4.3 billion in capital investment, \$16.1 billion for fuel, and \$4.1 billion for operation and maintenance, for a total system expenditure of \$24.5 billion.

In the LWR base case, the Northeast region spent \$6.3 billion in capital investments, \$11.0 billion for fuel, and \$2.9 billion for operation and maintenance, for a total system expenditure of \$20.2 billion. The Northeast opted to spend \$2.0 billion more in capital expenditures with the LWR available than if it were not. This increase, however, produced for the utility a system savings of \$5.1 billion in fuel costs and an additional \$1.2 billion savings in O&M costs. The total net system savings with the LWR option available was nearly \$4.3 billion or approximately 20%.

In the HTGR base case, the Northeast region spent \$6.3 billion in capital investment, \$10.5 billion for fuel, and \$2.9 billion for operation and maintenance, for a total system expenditure of around \$19.7 billion. The total net system savings with the HTGR as an option compared to having the LWR as the only available nuclear option was about \$450 million over the 20-year study, or a 2.5% system savings.

(The reader may note that these figures are significantly higher than those reported in the HTGR Market Assessment - Interim Report. The two reasons for this are (1) the recalculation of cost figures into 1980 dollars and (2) the correction of the HTGR heat rate input value.)

The power costs of the three base case systems are presented in year 2020 annual expenditures in Table 3.3-13 below:

Table 3.3-13

Year 2020 Annual Costs
($\$1980 \times 10^6$)

	Coal Base Case	LWR Base Case	HTGR Base Case
Investment	333	451	451
Fuel	442	277	262
O&M	148	91	91
Total	923	819	804

The above baseline results have been developed as a basis for analyzing the sensitivities of the various factors examined in Section 3.3.3. Graphic representations of these baseline results are presented in Appendix A, Figures A.1-5 and 6.

Energy Consumption - Through the use of the study model, fuel consumption for the base case scenarios was calculated. Total system energy consumption data are presented in Appendix A by Figures A.1-7 through A.1-9. The energy consumption figures extrapolated to coincide with national EPRI capacity projections are shown in Figures A.1-10 and A.1-11.

It should be noted that the total system differential in fuel costs between the HTGR and LWR base cases cannot be extrapolated directly from the input fuel cost differentials of the LWR and HTGR. The system fuel costs result from the optimum capacity dispatch calculated by OGP; therefore, the amounts of coal and oil burned in the two reference cases are not equal.

3.3.3 Sensitivity Analysis

In the previous section, the effect of non-nuclear and nuclear environments was discussed with both the LWR and the HTGR as available generation alternatives. In this section, perturbations to input variables were analyzed as to their effect on the total utility system. This included economic effects due to changing the variable of interest and economic effects due to alterations in the mix of other generation systems. The economic effects are given relative to the LWR base case unless stated otherwise, and the generation mix trends are discussed relative to the HTGR base case. With the Northeast system as the reference, the following HTGR parameters were individually varied: capital costs, fuel costs, operation and maintenance costs, forced outage rates, planned outage rates, and unit sizes. In addition, analyses were conducted on the overall effects of a 1% increase or decrease to utility load growth, and of the elimination of energy storage as a utility option.

Capital Cost

With nuclear power plants, capital cost is traditionally the most dominant factor in any economic analysis. In a direct comparison between the LWR and HTGR with the unit costs described in the reference cases of this study, a 5% increase in HTGR capital cost would more than offset the small fuel cycle cost advantage of the HTGR. However, in utility systems analyses, an increased capital cost for the HTGR may still result in HTGR penetration due to alterations in the optimum generation mix that meets the given constraints of system reliability. For example, when the capital cost of the HTGR was increased to 5% above that of the LWR, it still captured 40% of all nuclear additions. This case, however, proved to be slightly more costly to the utility than the LWR base case.

If capital costs were to be reduced to 7.5% less than the LWR, the utility would save over $900 million over 20 years. This savings becomes $5.3 billion when compared to the coal base case. Further reductions in capital cost continued to yield significant savings, and at a decrease of 10%, the system savings to the utility reached $1 billion.

Several system trends were apparent with perturbations to HTGR capital costs. As capital costs were increased, the market penetrability of the HTGR as described above was clearly compromised, and it would be fair to conclude that in the range of 5% above the LWR in capital cost, the HTGR can be considered only marginally competitive. When capital costs were decreased by 10%, the HTGR became very competitive and not only dominated the new and replacement baseload market but had a significant effect in the area of peaking capacity. The utility under that secenario added 400 megawatts less of gas turbines in favor of 300 megawatts more of energy storage. Not only was less oil burned in this scenario when compared to the HTGR base case, but load demands could be met with a smaller utility capacity. Further reductions in HTGR capital costs showed no additional perturbations to the generation mix, and indeed one would have to achieve unrealistic capital cost reductions to displace construction of the peaking units.

Fuel Cost

Input fuel costs for the HTGR base case shown in Table 3.3-3 show a disadvantage of 8% in cost per million BTU when compared to the LWR. However, when the respective plant heat rates are taken into account, this disadvantage becomes an 8.5% advantage in actual fuel costs relative to the LWR.

The HTGR base case showed the reference 20-year fuel cost savings to be around $450 million for the utility. When the input fuel costs of the HTGR were increased 5% to $0.773/MBTU, 12 of the 15 nuclear additions were HTGRs. However, there was essentially no utility savings when compared to the LWR base case because of generation mix perturbations. Reducing fuel costs by 7.5% to $0.682/MBTU yielded around $800 million in savings to the utility over 20 years. Further reductions in fuel costs, of course, yield even larger savings. At a decrease of 15% below the base case fuel costs (8.2% lower than an LWR), systems savings to the utility amount to nearly $1.3 billion over 20 years.

There were several apparent trends associated with perturbations to HTGR fuel costs. When these costs were increased from the reference HTGR base case, one less nuclear plant was added. The mix showed the addition of 570 megawatts of combined cycle, 500 megawatts of energy storage, and the deletion of 100 megawatts of gas turbine. Because this system installed 230 megawatts less than the reference, the lower reserve margins produced savings which partially offset the losses due to increased HTGR fuel costs. Decreasing the HTGR input fuel costs down to parity with the LWR caused the utility to add more HTGRs, more gas turbines, and less energy storage capacity while eliminating LWR and combined cycle additions. This trend changed as HTGR fuel costs continued lower in that fewer gas turbines were added in favor of energy storage. The primary reason here was that system savings could be derived from a switch from the inexpensive-to-build, costly-to-operate gas turbines to relatively expensive-to-build, inexpensive-to-operate energy storage systems. Some gas turbines were built, of course, to maintain an adequate system reliability.

Operation and Maintenance Costs

Operation and maintenance (O&M) costs were not addressed further than already examined and reported in the HTGR Market Assessment - Interim Report. For consistency's sake, however, these previous results have been extrapolated to coincide with the current Assessment efforts and are described briefly here. The fixed and variable components of O&M costs are primarily functions of unit size and number of actual operating hours. Unit size for this study was fixed, and actual operating hours were determined by forced and planned outage rates. The base case HTGR O&M costs are shown in Table 3.3-3 and were assumed to be at parity with the LWR. The study showed that a 10% reduction in HTGR O&M costs produced 20-year utility savings of over $620 million when compared with the LWR base case.

Trends associated with varying O&M costs should resemble those of varying fuel cost (although not nearly to the same degree) because like fuel costs, cumulative O&M costs are directly proportional to plant operating hours. Based upon this similarity, additional O&M scenarios were not developed.

Forced Outage Rates

A key item not addressed in the earlier efforts presented in the HTGR Market Assessment - Interim Report was forced outage rates

(FOR). The input HTGR FOR for this Assessment was assumed to be equal to that of the LWR. When the HTGR FOR was reduced by 10 days (18%), the savings to the utility were approximately $650 million relative to the LWR base case, a large fraction of which is attributable to the fuel savings produced by the HTGR. The apparent trends caused by reducing FORs indicate that as a result of the overall increased availability of the HTGR, less generating capacity was needed. The utility installed 915 megawatts less than the HTGR base case. This fact is significant as the capital requirements of the utility were eased. The utility did not add 1200 nuclear megawatts and 300 gas turbine megawatts, which were added in the HTGR base case. Instead, it added 285 megawatts of combined cycle and 300 megawatts of energy storage capacity. This increased availability caused the displacement of coal and oil consumption by 252 million BOE (Barrels of Oil Equivalent), an average of 12.6 million BOE annually.

The savings generated by the 10-day reduction in FOR should be understood to be very conservative and possibly a lower bound. While the OGP code could be an excellent tool for FOR studies, it calculates FOR by derating a unit evenly across all generating periods. This study did not address the effects of units being forced out during critical load demand periods.

Planned Outage Rates

When the planned outage rates (POR) of the HTGR were reduced by 10 days (20%), the savings to the utility were approximately $570 million over 20 years relative to the LWR base case. POR does not have the same effect on the utility as does FOR, a fact well corroborated by industry experience. This is because when nuclear units are down for scheduled maintenance, it is usually during off-peak months and small increases or reductions in POR may not dramatically affect a utility system.

The apparent trends shown by reductions in POR closely follow those of reducing FOR, but not as efficiently. In other words, even though one less nuclear unit and 530 total less megawatts than the HTGR base case were added, the system was not as cost effective as the FOR sensitivity case described above. Gas turbine capacity was less by 200 megawatts and energy storage increased by 300 megawatts, but oil burning combined cycle capacity increased by 570 megawatts. This system did, however, show a significant reduction in coal and oil consumption over the LWR base case as 145 million BOE or 7.3 million BOE of these fuels were displaced annually.

Plant Size

Plant size sensitivities were analyzed in efforts reported in the HTGR Market Assessment - Interim Report. These were done on the basis of maintaining constant ($/KWe) plant costs for unit sizes studied, i.e., 1200, 1000, and 800 megawatts. This unrealistic assumption was made to provide an indication of the effects on the system of having a smaller plant available for addition, thereby quantifying through parametric evaluation the allowable premiums for smaller plant size. As noted in the Interim Report, utility savings were realized by going to smaller units because of lower system reserve margins which result from smaller increments of installed capacity. Coupled with perceived advantages in the areas of reliability and O&M, the above incentives have driven current HTGR designs to be of around 800 to 900 megawatts.

When the HTGR plant size was reduced from 1200 MWe to 1000 MW, a total system savings to the utility of $400 million was realized. The bulk of the savings was derived from nuclear fuel cost savings with the better efficiency of the HTGR and the replacement of 1140 megawatts of intermediate duty units. When the HTGR plant size was reduced to 800 megawatts, the total system savings to the utility was increased to $510 million. These savings again were derived primarily from fuel savings as described above.

There were several noticeable trends associated with reductions in HTGR plant size that were in addition to its domination of the baseload market and its significant capture of the intermediate market. The change in reserve margin over time was from 29.4% to 24.0% and to 22.5%, respectively, for the two cases described above. With the reduction of plant size, the utility could add capacity that could more readily match load growth, thereby eliminating the overbuilding normally present due to discrete capacity additions. This tended to make the total system a more reliable one. The system installed capacity was reduced by 510 and 910 megawatts, respectively, for the two cases described above. By reducing plant size, then, the utility matched load requirements with a smaller generation system.

Two additional cases were done on plant size, the first with 1200 MWe LWRs and 800 MWe HTGRs, and the second with 800 MWe LWRs and 800 MWe HTGRs. All other inputs were the same as in the HTGR base case. As before, $/KWe plant costs were held constant. In the first case, both LWRs and HTGRs penetrated the utility market. 7200 megawatts of LWR and 11200 megawatts of HTGR were added. In the second case, all nuclear additions were HTGRs. Besides associated utility savings, reserve margins were lower and the utility built a generating system that was 1000 megawatts smaller than the HTGR base case. This case underscored the importance of unit size relative to system reserve margin and installed capacity. It must be understood, however, that the first order effect of higher $/KWe for smaller plants was not factored into this analysis. How the systems will actually respond to smaller units with higher capital costs remains to be examined.

Load Growth Rates

Two cases of load growth rates were studied after the year 2000, 2.5% and 4.5% per year. The initial case, 2.5% per year, can be regarded as a conservation case, the second, 4.5% per year, a high growth case. The results of the conservation case underline the importance of conservation not just to the consumer but to the utility as well. By reducing the load growth by 1% from 3.5% to 2.5% per year, the reduction of the utility's revenue requirements is substantial. When compared to the LWR base case, revenue requirements were reduced $3.2 billion over the 20 years or an average of $160 million a year. Extrapolated to national projections made by EPRI, these figures become $226 billion over 20 years or an average of $11 billion a year.

This reduction was primarily derived by installing 5315 megawatts less than would otherwise had been necessary. When compared to the LWR base case, over 20 years, the utility consumed less energy by 285 million BOE, an average of 14 million BOE a year. Translated to national terms, these figures become 20 billion BOE over 20 years for an average of 2.8 million BOE saved a day.

The effects of a 1% increase in load growth are equally as dramatic. The utility must grow from nearly 18 gigawatts to 40 gigawatts in 20 years. Along the way, the utility will spend over 20 years $6 billion for capital investment, $9.6 billion for fuel, and $2.6 billion for O&M--approximately $3 billion more than the LWR base case. Extrapolated to U.S. projections, this increase becomes over $210 billion. Energy consumption figures are equally as large: supplies for an increased energy consumption by 320 million BOE, or an average of 16 million BOE annually, must be found. On a national basis, this would become an additional energy demand for over 3 million BOE a day just for electricity production.

Effects of Energy Storage

All three base cases were re-analyzed under the assumption that energy storage would not be a viable energy alternative during the study period. The economic penalties to the utility range from $235 million, $380 million, and $550 million for the coal, LWR, and HTGR base cases respectively. As can be seen, energy storage is most attractive in environments which are dominated by capital-intensive but inexpensive-to-operate plants. The savings derived by having the HTGR available in conjunction with energy storage are greater than with its LWR counterpart under the base case assumptions because the HTGR's more economical power is stored and then utilized as needed during system peak demand periods. It can be seen from this analysis, however, that the introduction of energy storage into any utility environment could create lower revenue requirements. Extrapolated to the national environment, the penalty of not having energy storage as an available alternative would be $16.5 billion, $26.9 billion, or $38.8 billion for the respective base cases outlined alone.

Based on resource utilization, the effects of energy storage are as compelling. In the coal base case without energy storage, the utility added 1200 megawatts less of coal, 855 megawatts more of combined cycle, and 1600 megawatts more of gas turbine for a total system of 33.2 gigawatts (255 megawatts larger than the reference coal base case) by the year 2020. It was necessary to increase the overall peaking and intermediate duty capacity because of the elimination of energy storage systems which served to shave utility peak loads. This in turn caused an increase in the amount of oil that was consumed by over 30 million barrels. Based on a national extrapolation, this translates to an increase in oil consumption of over 2 billion barrels for the 20-year period. The LWR and HTGR cases analyzed without energy storage systems showed about the same displacement of oil consumption.

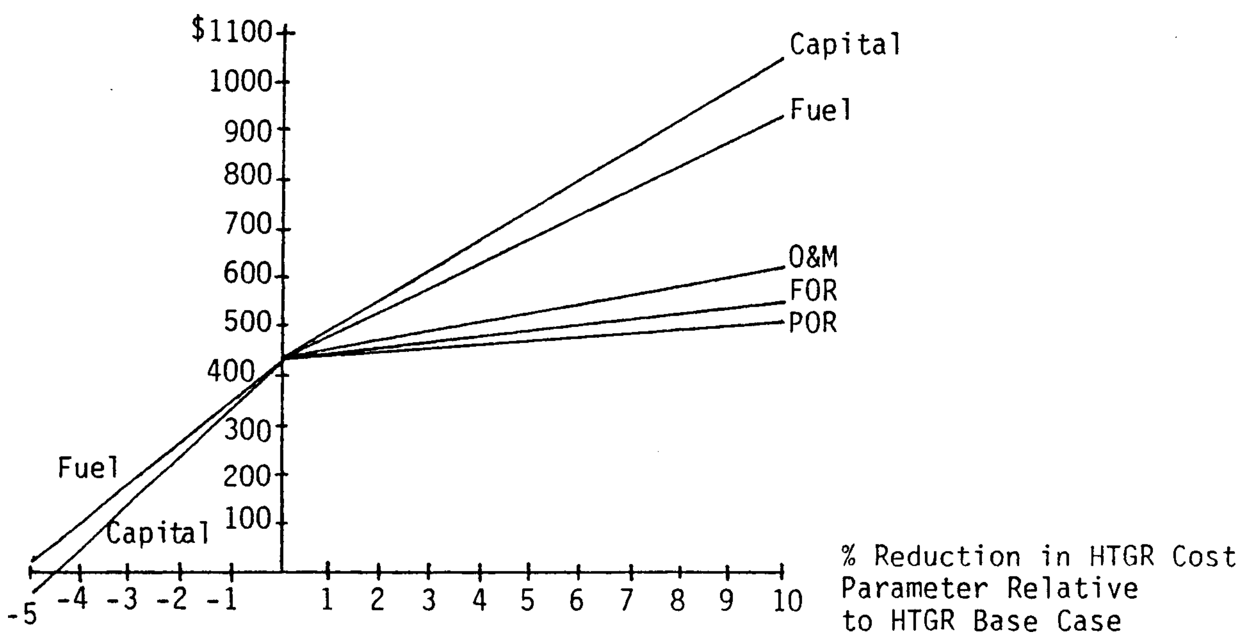
Because of time constraints, it was not possible to examine the HTGR and the energy storage systems which are currently being considered for integration with it, namely, the thermochemical heat storage system and the molten salt sensible heat storage system. While the absence of analyses of these systems prevents the drawing of quantitative conclusions, the results of this section do indicate substantial incentives for the continued study of these systems.

Sensitivity Summary

As expected, similar reductions of the various HTGR input parameters do not yield equal system savings. Further, the savings are nonlinear for the parameter of interest due to the discrete addition of capacity and the program's ability to optimize this capacity for a given year's operation. However, straight line curve fitting does efficiently represent the data generated for this study. While the trends depicted on Figure 3.3-14 are accurate indicators, the associated dollar figures should be treated as a measure of the magnitude of the relative economic effects and not as absolute dollar savings.

Figure 3.3-14

Utility System Savings
$\$10^6$ (1980)



Applying the above figure, one can estimate the equivalent percent reduction in the respective variables required to achieve an equivalent system savings. The following table gives the percent reduction for each variable needed so that it would be equivalent to a 5% reduction in capital cost.

Table 3.3-15

Comparative Impact of Variable Reduction

HTGR Variable	% Reduction Necessary to Equal 5% Decrease in HTGR Capital Cost
Capital Cost	Reference
Fuel Cost	6.4
O&M	16.8
Forced Outage Rate	26.0
Planned Outage Rate	45.9

While these figures would indicate that reducing capital cost is of greater importance than reducing other parameters, it does not consider the added design and manufacturing costs associated with the indicated savings. For example, a reduction of the FOR of 11 days (26%) may be less costly to achieve than a 5% reduction in capital costs. Therefore, this table should not dictate the absolute importance of any design parameters, but it does present relative importance to guide future tradeoffs involving development priorities.

It has been shown that the potential utility and national dollar benefits that could accrue from deployment of the HTGR are substantial if the HTGR can be developed at capital costs equivalent to those of the LWR and maintain its fuel cycle advantage. Of course, reductions in HTGR capital and fuel costs yield larger savings; however, increases in either parameter dramatically degrade its economic posture. In fact, with capital or fuel cost increases of as little as 5%, these savings all but disappear.

To put these discussions of relative savings into better perspective, Table 3.3-16 shows 20-year savings for various market penetration assumptions using the base case economic assumptions for the LWR and the HTGR, i.e., parity capital cost and 8.5% HTGR advantage in actual fuel costs.

Table 3.3-16

Potential Markets and Savings

Market Assumptions	Utility: $ Δ Million (1980)	Utility: GWe HTGR by Year 2020	Total U.S.: $ Δ Billion (1980)	Total U.S.: GWe HTGR by Year 2020
1. LWRs replace retired LWRs. All nuclear additions are LWRs.	Base	0	Base	0
2. LWRs replace retired LWRs. 20% nuclear additions are HTGRs.	26	1.7	2	118
3. LWRs replace retired LWRs. 100% nuclear additions are HTGRs.	130	8.4	9	592
4. HTGRs replace retired LWRs. 100% nuclear additions are HTGRs.	165	10.8	12.	761
5. HTGRs replace retired LWRs, coal units. 100% baseload additions are HTGRs.	436	19.2	31	1353

It should be remembered that this table is strictly a presentation of the relative economic effects of the HTGR and does not address the other market factors identified in Section 2.1 which will affect the HTGR's market penetration rate. These other factors, which are examined in Section 4, create nonquantifiable incentives, or disincentives, which must be evaluated along with the economics presented here.

3.4 CONCLUSIONS

Through the use of a representative utility system and the Optimized Generation Planning code, a model has been developed to analyze the HTGR in the environment in which it presumably would exist--the utility environment. Several conclusions relative to the HTGR can be drawn from the systems analysis and are outlined below:

- Substantial dollar savings can be derived from reductions in all HTGR parameters, but reductions in capital and fuel costs prove the most significant and should be pursued with the higher priority.

- Deploying HTGRs that have the economic and performance characteristics used in this study in place of LWRs can yield 20-year energy savings ranging from 100s of millions barrels-of-oil-equivalent for a single utility to 10s of billions barrels-of-oil-equivalent nationwide.

- Energy storage savings appear to offer a very substantial incentive to continue study of the integration of the HTGR with thermochemical and sensible heat energy storage systems.

The model enabled this study to analyze factors other than those related to HTGRs. A few conclusions drawn from this analysis are as follows:

- Determination of an optimum plant size should not be made without intensive review of utility generating characteristics and requirements.

- Conservation is vitally important and a reduction in electric load growth from 3.5% to 2.5% can yield a revenue requirement reduction of $11 billion a year nationwide. This same reduction in growth yields savings of 2.8 million barrels-of-oil-equivalent a day nationwide.

- Deployment of energy storage systems can yield 20-year savings of tens of billions of dollars and several billion barrels-of-oil-equivalent nationwide.

3-30

4.0 HTGR BENEFITS ASSESSMENT

4.1 SAFETY AND LICENSING

This section will summarize an assessment of the various characteristics of the HTGR which affect its ability to be safely operated as well as its perceived licensability. These characteristics will be assessed relative to the latest engineering information that is available to GCRA as well as the latest regulatory criteria. The reader who is unfamiliar with configurations of the various HTGR systems should refer to Sections 5.1, 6.1, and 7.1 for further system descriptions.

HTGR-SC

Proponents of the HTGR have long cited its inherent safety characteristics as a major advantage of the technology. Beyond licensing of the Fort St. Vrain demonstration plant, evaluation of these characteristics by regulatory authorities has been limited to the review of construction permit applications for the Summit and Fulton HTGR generating stations. The Fulton and Summit applications were withdrawn prior to granting of the construction permits; however, Summit had received a complete NRC Safety Evaluation Report and a Limited Work Authorization. These inherent safety characteristics of the HTGR are presented in Table 4.1-1 and are discussed below.

The HTGR core is constructed exclusively of ceramic materials, primarily graphite. These materials maintain their integrity at very high temperatures, well above normal reactor operating conditions. The core is designed with a low power density and strong negative temperature coefficient of reactivity, thereby creating relatively slow reactor temperature and power transients. In the event of loss of core cooling, the graphite acts as a heat sink. Interruptions of core cooling of approximately 30 minutes can be tolerated without any damage to primary system components. Approximately three hours is available to restore cooling before fuel damage or radioactivity release occurs. These times are based on the 3360 MWt HTGR core design. Somewhat longer times are expected with smaller cores.

Another inherent safety characteristic of the HTGR is the use of helium as the primary coolant. Helium cannot react with the core or reactor internals because it is chemically inert and remains in the gaseous phase. Because heat can be removed from the reactor core with any gas, even ambient air, it is not necessary to maintain a full inventory of coolant in the reactor vessel during cooldown.

A significant design feature of the HTGR is the prestressed concrete reactor vessel (PCRV), which was introduced in gas reactors in Britain because of its safety characteristics. It is a structurally redundant concrete monolith which encloses the entire primary system. The strength and redundancy of the PCRV are provided by a large number of steel tendons that run axially through and circumferentially around the vessel. The concrete, which also acts as a radiation shield, is under compression; therefore, cracks are not subject to propagation.

In order to quantify the relative worth of HTGR inherent safety characteristics, General Atomic Company performed the Accident Initiation

Table 4.1-1

KEY INHERENT AND PASSIVE SAFETY CHARACTERISTICS OF THE HTGR

Inherent or Passive Feature	Relevant Properties	Safety Significance
Reactor core	High heat capacity	Slow transient response
	Low power density	Allows adequate time for remedial measures, both within and external to plant
	Strong negative temperature coefficient	Fast-acting shutdown system not required
	Graphite cannot melt but may locally sublime	Structural integrity of core maintained for days following loss of cooling
	Coated particle ceramic fuel	Slow controlled release of volatile nuclides under no-cooling conditions
Helium coolant	Single-phase gas	No boiling, bubbles, liquid level, or pump cavitation problem; no added coolant inventory needed for core cooling, only forced circulation
	Neutronically transparent	Negligible reactivity effects
	Chemically inert	No chemical fuel cladding-coolant interactions
	Low stored energy	Reduced containment damage potential
PCRV	Multiplicity of tendons	Failure of individual structural members inconsequential
	Tendons shielded by concrete	Neutron embrittlement and subsequent fracture eliminated
	Concrete under compression	Cracks self-sealing, do not propagate
	Massive structure	Effective retention of radioactivity; retains great fraction of heat escaping core
Containment	Not unique to HTGRs but particularly effective because of above-listed inherent features	

and Progression Analysis (AIPA) study using probabilistic risk assessment methodology. It studied a wide spectrum of accident sequences which might result in release of radioactivity from a large HTGR steam cycle plant. A summary table of results of the AIPA is presented in Table 4.1-2 from Reference 7. When this table is compared with the summary results of the WASH-1400 report, the HTGR compares quite favorably in each category to the LWR. It should be noted, however, that direct comparison of the results of the two studies should be avoided as the analyses were performed by different groups using different uncertainty limits. The AIPA study received peer review from several offices of the NRC, Brookhaven National Laboratory, Oak Ridge National Laboratory, Aerojet Nuclear Company, KFA in Julich, FRG, and the Safety and Reliability Directorate of the United Kingdom Atomic Energy Authority. Generally, the comments did not change or contest the major conclusions of the study. Work is continuing to study new initiating events, fission product transport assumptions under accident conditions, and in other areas where the uncertainty bounds which were originally used are considered to require further refinement.

As part of the Nonproliferation Alternative Systems Assessment Program (NASAP) study, NRC submitted to DOE a list of 29 questions and comments on 8 topics concerning the safety and licensing documentation for the proposed large steam cycle HTGR design. These questions and the General Atomic Company responses are presented in Reference 8. The major topics and their responses are reviewed below:

- Use of Graphite as a Structural Material

  The design criteria for graphite structures has not yet been completed or approved. A joint subcommittee of the American Concrete Institute and ASME has been formed to generate a code section for graphite. Many of the items before the subcommittee require experimental verification which will be obtained from the ongoing base technology program. Tentative adoption of the code is at least a year away.

  Graphite corrosion is another significant area of graphite research. Oxidation of the graphite occurs at high temperatures in the presence of water vapor. Experimental work to date indicates that oxidation under HTGR operating conditions causes a surface predominated attack which can be allowed for in the structural analysis and design. GAC's position is to design the graphite components so that the minimum safety factors required by the proposed design criteria will be available at the end of plant life. Design oxidation rates and design basis events for water ingress into the PCRV have not yet been determined or approved.

- Core Seismic Response

  NRC questions in this area centered on the seismic design criteria and the seismic analysis methods to be used. Several computer codes have been written which utilize test data for values used in the models. Large array tests have been performed to verify the codes and to give information on the characteristics of the core for design purposes. There are no major open licensing issues in this area.

Table 4.1-2

RISK ASSESSMENT RESULTS FOR HTGR FROM AIPA STUDY

Accident Consequences[a]	Accident Frequency (reactor-year^{-1}) 10^{-6}	10^{-7}
Early fatalities	<1	<1
Early illnesses	<1	<1
Property damage, $ million	<1	2
Relocation area, sq miles	0	0
Decontamination area, sq miles	0	0.2
Latent cancer fatalities[b]	1	8
Thyroid nodules[c]	10	100
Genetic effects	<1	1

[a] Representative U.S. site.

[b] Beir Commission recommendations used.

[c] Sum of benign and cancerous nodules.

Source: Reference 7

- Fuel Behavior

  A large data base of information was compiled on highly enriched uranium (HEU-93%) fuel in a 750°C (1382°F) helium environment. The reference fuel for the lead project is LEU (20% enriched). As a result, much experimentation remains to be done on LEU fuel particles and their properties, including fission product retention. As higher temperature applications are pursued, i.e., 850°C (1562°F) core outlet temperatures for the Gas Turbine and Reformer variants, new data will need to be generated for these fuels in order to meet the NRC licensing criteria.

- In-Service Inspection and Testing

  Section XI, Division 2 of the ASME Boiler and Pressure Vessel Code contains the proposed guidelines for ISI of HTGR components. The categories of affected components include those required for (a) shutdown heat removal, (b) control of nuclear reactivity, (c) detection or control of chemical ingress, and (d) controlled primary coolant depressurization. An open question in this area is the requirement for the possible ISI of the PCRV liner. GAC's current position is that a thermally insulated liner will not require ISI. This remains to be confirmed by the NRC. NRC did, however, require ISI of the core support structure for the Fulton HTGR.

- Primary System Integrity

  Corrosion effects within the primary loop will be insignificant because of the inert helium environment except in two potential areas: metal carburization, and oxidation in the lower graphite core support blocks due to impurities in the helium. The carburization problem increases with temperature and is, therefore, of more concern in the 850°C core outlet applications of the HTGR. Research in these areas is continuing to establish appropriate design criteria.

  The design bases for the design of the PCRV closures are not yet approved by the NRC. Most closures are designed and fabricated to ASME Code Section III, Division 1. In previous licensing efforts, these closures have utilized flow restrictors to limit the free flow area to 100 in^2 or less in the event of a failure. LWRs are not required to assume failure of Class 1 pressure vessels; therefore, the GAC position is that the assumption of such failures for the HTGR is excessive and should not be considered as a DBA, provided the penetrations and closures are not operated at temperatures above those at which ASME Section III applies. Steel closures whose temperatures exceed that allowed by the Code may be used at steam pipe penetrations. These are designed to meet the rules of high temperature code cases and utilize flow restrictors. Prestressed concrete closures used for large heat exchanger cavities are designed and constructed to ASME Code Section III, Division 2. Due to their redundant prestressing elements, GAC considers their gross failure to be incredible and, therefore, precludes rapid depressurization due to their failure.

Another item concerning primary system integrity is acoustic excitation within the primary system. For the Steam Cycle and Reformer variants, the primary source of this acoustic excitation is the main circulators. In the Gas Turbine plant, the turbomachinery will generate much higher noise levels which may affect the liner insulation. Studies are continuing in this area to model the acoustic propagations as well as to determine the long-term effects on reactor internals. This is a major area of uncertainty for the HTGR-GT.

- Emergency Core Cooling Provisions

  During the Fulton and Summit licensing process, the NRC treated the CACS circulators and shutoff valves as prototypical items which deserved special testing programs. CACS testing criteria still must be developed for preoperational design verification and on-line testing. Also, a computer program must be developed for assessing the stability margin of the core auxiliary heat exchanger. While these are still open licensing issues, they are not expected to impact overall plant licensability.

- Anticipated Transient Without Scram (ATWS)

  The subject of ATWS remains an unresolved licensing and design issue. There have been some preliminary studies of HTGR-steam cycle ATWS to support earlier licensing efforts, but they were directed toward NRC interpretation of LWR ATWS requirements. Work remains to be done to resolve the ATWS issue for the HTGR on the basis of its inherent safety features. This issue is not expected to impact overall plant licensability.

HTGR-GT

The safety and licensing issues discussed above are applicable to the generic HTGR design and were developed from reviews of the steam cycle concept. The direct cycle or Gas Turbine (GT) version of the HTGR has additional major safety and licensing issues which result from the following major design differences:

Relative to the Steam Cycle HTGR, the Gas Turbine has:

- 17% higher core outlet temperature (850°C vs. 700°F)
- 50% higher operating pressures and differential pressure across the core
- Potentially higher fission product release due to higher temperatures
- 50% higher primary coolant flow rates
- The turbomachinery located within the PCRV with the resultant acoustical effects on the PCRV internal components
- A large rotating shaft penetrating the PCRV and the primary containment whose failure would jeopardize primary system integrity

- Precoolers and recuperators which require ASME qualification

- The possibility of turbomachine lubricant leakage into the primary system

- The possibility of overstressing the thermal barrier due to the effects of rapid internal pressure transients

The safety significance of several of these items is discussed in more detail below:

- Shaft Seal Failure

  The turbomachine/generator shaft penetrates the primary coolant system boundary. Failure of the seal can cause rapid depressurization of the PCRV. The present design also calls for location of the generator outside the containment building, thereby adding an additional rotating shaft seal in the containment wall. A postulated failure which could cause loss of integrity of both the PCRV and containment rotating seals would probably be unacceptable and remains a major licensing concern.

- Internal Pressure Equilibration Accidents

  During normal operation of the HTGR-GT, large pressure differentials exist across the turbine and compressor sections of the turbomachine ($\sim$ 685 and 743 PSIA respectively). A failure of the turbomachine which would cause the collapse of these differentials is called an Internal Pressure Equilibration Accident (IPEA). GAC has recently completed an in-depth study of the licensing effects of such an accident and has concluded, based on existing turbine and turbomachine failure rate data, that a defensible failure rate for the turbomachine is 10^{-4} per machine-year. Based on this probability, the catastrophic failure of the turbomachine must be assumed as a design basis event. The study also concluded that the consequences of such an accident strongly depend on the assumed rate of pressure differential collapse. A conservative assumption that the turbine will completely deblade in one revolution at 42% overspeed, or .012 seconds, results in a depressurization rate in the core outlet plenum of 6310 psi/sec over .01 seconds (Reference 10). This speed assumes failure at the free-free critical speed. The stresses imposed on the reactor internals by this accident must be combined with the stresses imposed by the safe shutdown earthquake because of its classification as a DBE. The results of preliminary analyses show that redesign of the core support posts, permanent side reflector posts, CACS components and the core support structure will be required if the above design assumptions are utilized. It appears that in order to utilize less conservative assumptions than those above, a testing program will be required on a prototype turbomachine to study its operation and failure modes.

- Turbomachine Missiles

  In addition to causing rapid pressure transients, turbomachine failures can create high energy missiles. The design of missile shields to contain blade and rotor fragments is under way; however, these designs will be affected by the results of the turbomachine failure testing.

- CACS Design

  The turbomachine forms the principal resistance to reverse flow through each power conversion loop. The design basis for the CACS flow requirements assumes a single turbomachine failure which reduces the loop flow resistance. This design basis and the amount of resistance that can be assumed after a turbomachine failure must be analyzed and accepted.

- Overpressure Protection

  Unlike the HTGR-SC, there is no identified source for overpressurization of the PCRV in the HTGR-GT. It is proposed that overpressure protection as required by the ASME Code be provided by internal pressure relief by using safety grade valves in each power conversion loop to regulate pressure from high to low pressure portions of the loop. It is not anticipated that this issue will impact the overall plant licensability.

HTGR-R

The licensing issues for the HTGR Reformer system are essentially the same as those for the steam cycle with several major additional ones related to the nature of the reformer gas components. The current reference design locates the reformer in the secondary loop with gas-to-gas intermediate heat exchangers located within the PCRV (indirect cycle). This reduces the probability of water ingress into the core relative to the steam cycle. However, the HTGR-R operates at higher temperatures, 850°C core outlet; therefore, many of the analyses for temperature-related effects on fuel and core internals remain to be completed. It should also be noted that economic incentive for the HTGR-R may lead to 950°C or higher core outlet temperature and location of the reformers directly in the PCRV (direct cycle). This configuration would result in the presence of hydrogen, methane, and carbon monoxide within the PCRV and the containment in potentially explosive mixtures. To avoid the potential licensing difficulties of this configuration, the indirect reforming cycle was selected for the Lead Project option.

To date, a probabilistic risk assessment (PRA) has not been performed for the HTGR-R. Until one is completed, a quantitative comparison of the safety of the HTGR-R relative to other reactor plants cannot be made. It is expected, however, that the uniqueness of the HTGR-R due to the generation and storage of potentially explosive synthesis gas with the presence of methane and toxic carbon monoxide will result in different PRA results from those obtained for the HTGR-SC presented in Table 4.1-2. How these results will vary cannot yet be determined.

Major licensing issues unique to the HTGR-R include the minimum safe distance between the reactor and the gas storage facilities. Presently, approximately 1.2 miles is expected to be required between the synthesis gas storage cavern and the reactor containment. The reformers, because of the detonation capability of the gases they contain, are expected to require 200 feet of distance from the containment, but this too must be confirmed in the licensing process. The toxicity of the carbon monoxide of the synthesis gas is a major concern in that precautions must be taken to protect against its leakage with systems that can quickly detect and isolate the leak. Another possible licensing concern that will need to be addressed is the leakage or diffusion of tritium into the product stream with resultant transmission off-site.

Summary

In conclusion, work performed to date supports the contentions that the HTGR is, in fact, an inherently safe reactor concept. The safety of the three HTGR systems relative to each other can only be assessed with an uncertainty dependent upon the amount of engineering and analysis that has been performed on each. In this regard, it appears that the Steam Cycle HTGR will have the path of least resistance through the licensing process.

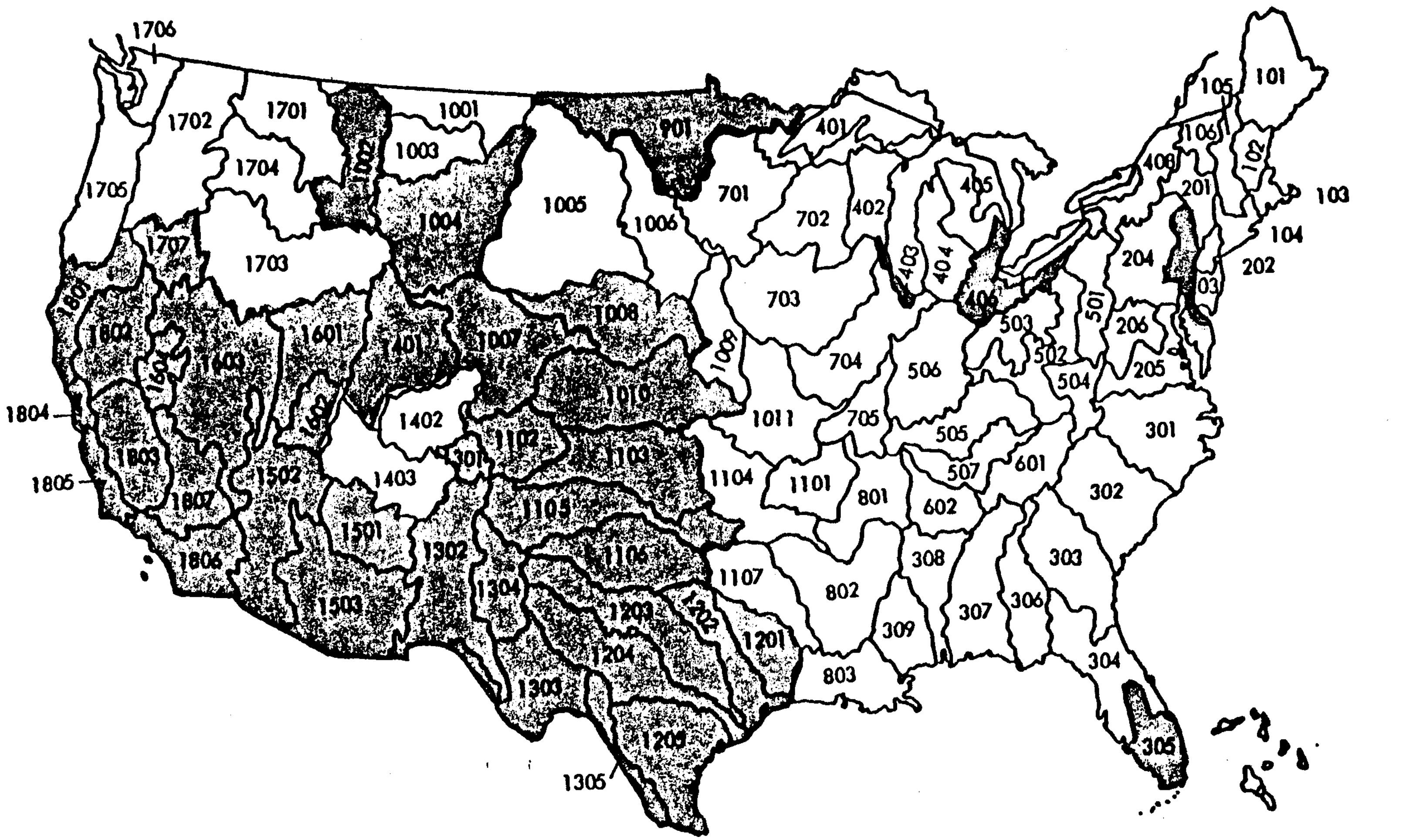
4.2 WATER UTILIZATION

One of the major claims of HTGR proponents has been the assertion that the HTGR can be cooled efficiently while consuming less water than current LWR or fossil-fired plants. This claim has been presented as a major incentive for the development of the HTGR-GT. Several studies in the past have shown that, indeed, the HTGR-SC with wet cooling consumes 15% to 25% less water than a wet-cooled LWR under similar site conditions due to its higher thermodynamic efficiency and lower reject heat load (Reference 11). A study performed in 1975 by General Electric Company for the Electric Power Research Institute (Reference 29) attempted to quantify the cooling performance of the HTGR-GT relative to other nuclear systems. It also projected areas of the country where some form of dry cooling would be needed by the year 2000. The results of this study were documented in the GCRA HTGR Market Assessment - Interim Report. In order to better quantify the size of the potential dry cooling market in the 2000-2020 time frame, which is when the HTGR-GT is targeted for commercialization, GCRA enlisted the Hanford Engineering Development Laboratories (HEDL) because of its Water Use Information System and its capabilities. The results of the HEDL study (Reference 2) are presented in this section.

The study utilized the projections of the Water Resource Council Second National Water Assessment and the HEDL data base to identify aggregated sub-areas (ASA) where surface water deficiencies would exist by the year 2020. These areas are shown in Figure 4.2-1. The study then utilized the econometric model described in Section 2.2.1 to derive a projected electric energy demand by NERC region in the years 2000, 2010, and 2020. These results are shown in Table 2.2-1. This case was taken as the median, and high and low cases were also generated. They are shown in Table 4.2-2. Two separate techniques were used to determine where the capacity would be located to serve the projected demands. The first technique

Figure 4.2-1

Location of Surface Water Deficient ASAs Forecasted for the Year 2000



HEDL 8005-108.4

Source: Reference 2

Table 4.2-2

Forecast of Installed Capacity by NERC Region (GW)

High-Case Scenario

Region	2000	2010	2020
ECAR	242	339	436
ERCOT	94	131	169
MAAC	83	116	150
MAIN	117	164	211
MARCA	60	84	108
NPCC	95	171	306
SERC	296	414	533
SWPP	156	218	281
WSCC	226	317	407
Total	1370	1954	2466

Low-Case Scenario

Region	2000	2010	2020
ECAR	211	246	276
ERCOT	82	96	107
MAAC	73	85	95
MAIN	102	119	133
MARCA	53	62	69
NPCC	83	97	109
SERC	259	302	339
SWPP	137	160	179
WSCC	198	231	259
Total	1200	1398	1566

Source: Reference 2

located the new capacity in existing power generation areas (PGA). This is consistent with the theory that many future plants will be located on existing power plant sites. The second technique used a population-weighting factor which located the new capacity in proportion to projected population location. Projected growth rates for cogeneration, and retirements of existing plants were calculated to project the total central power plant capacity that will need to be constructed during the period in each ASA. Overlay techniques were used to determine the fuel mix of the capacity in each ASA. Coal, geothermal, solar, and biomass projections were made. Nuclear projections were based on a total installed nuclear capacity of 250 GWe in 2000 and 600 GWe in 2020. The end result is a projection of the number of GWe of new electrical capacity that will require either totally dry or dry/wet cooling in each ASA for three growth scenarios. These requirements are further defined by projections for fossil, nuclear, and other heat sources. Figure 4.2-3 summarizes these findings using the PGA disaggregation technique. Figure 4.2-4 presents the results using the population-weighting technique. It can be seen that even in the low-growth scenario in Figure 4.2-3, some form of dry cooling will be required for 170 GWe of capacity. For the median-growth case, 257 GWe will require some form of dry cooling or 30% of all capacity additions. Figure 4.2-5 shows the location of capacity additions requiring some form of dry cooling using the PGA technique for the base case. The numbers indicate the number of GWe requiring dry or dry/wet cooling. Figure 4.2-6 shows the same information using the population-weighting technique.

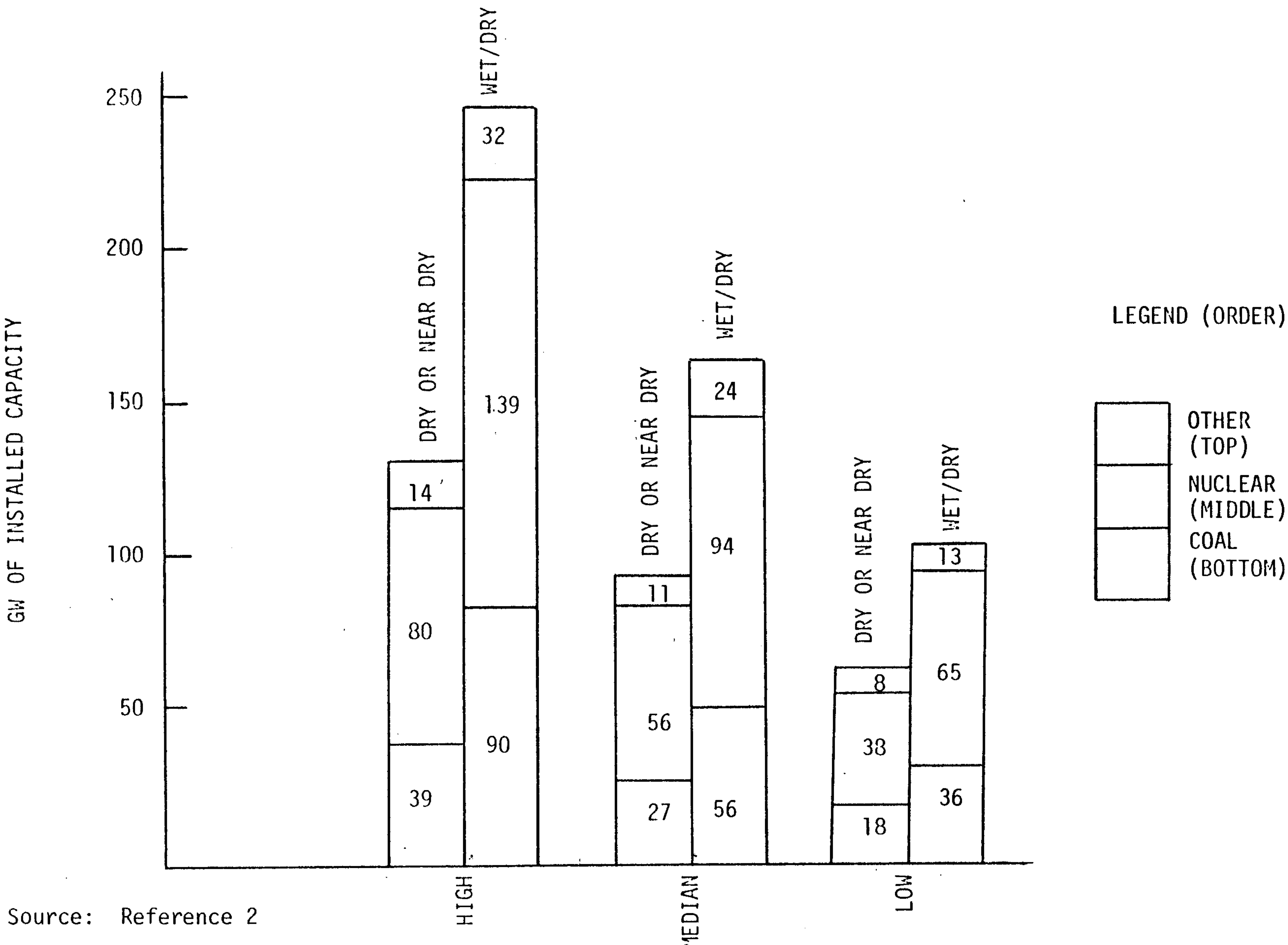
Based on the above data, there appears to be a substantial market for dry cooling technology after the year 2000. In order to evaluate the market potential of the HTGR-GT based on these findings, GCRA contracted with United Engineers & Constructors Inc. (UE&C) to perform an economic evaluation comparing the HTGR-GT to comparably sized LWR and coal plants, all at a common site with cooling systems optimized for given water consumption constraints. The parameters of these plants are given in Table 4.2-7. Water consumption was constrained in these analyses because the HEDL study indicates that water shortages will be manifested by constraints on water consumption and not by higher water prices (Reference 2). All analyses were performed for a site at Modesto, California, because it exhibits characteristics which are representative of many of the areas where dry cooling will be required; however, cooling system performance and evaluated costs are extremely site-dependent. The results obtained at the Modesto site, while valid only at that particular site, are considered to be representative of the results that would be obtained elsewhere in the dry cooling market areas.

UE&C designed an optimized cooling system for each plant with a given water constraint. Six cost penalty categories were then evaluated against the system performance with site-specific temperature variations. These penalties were evaluated on an annual basis, capitalized over the plant lifetime, and added to the capital cost of the cooling system. The sum of the capital cost and the capitalized penalty costs is called the total evaluated cooling system cost.

The results of the analyses are shown graphically in Figures 4.2-8, 9, and 10 for the fossil plant, the LWR, and the HTGR-GT respectively and are

Figure 4.2-3

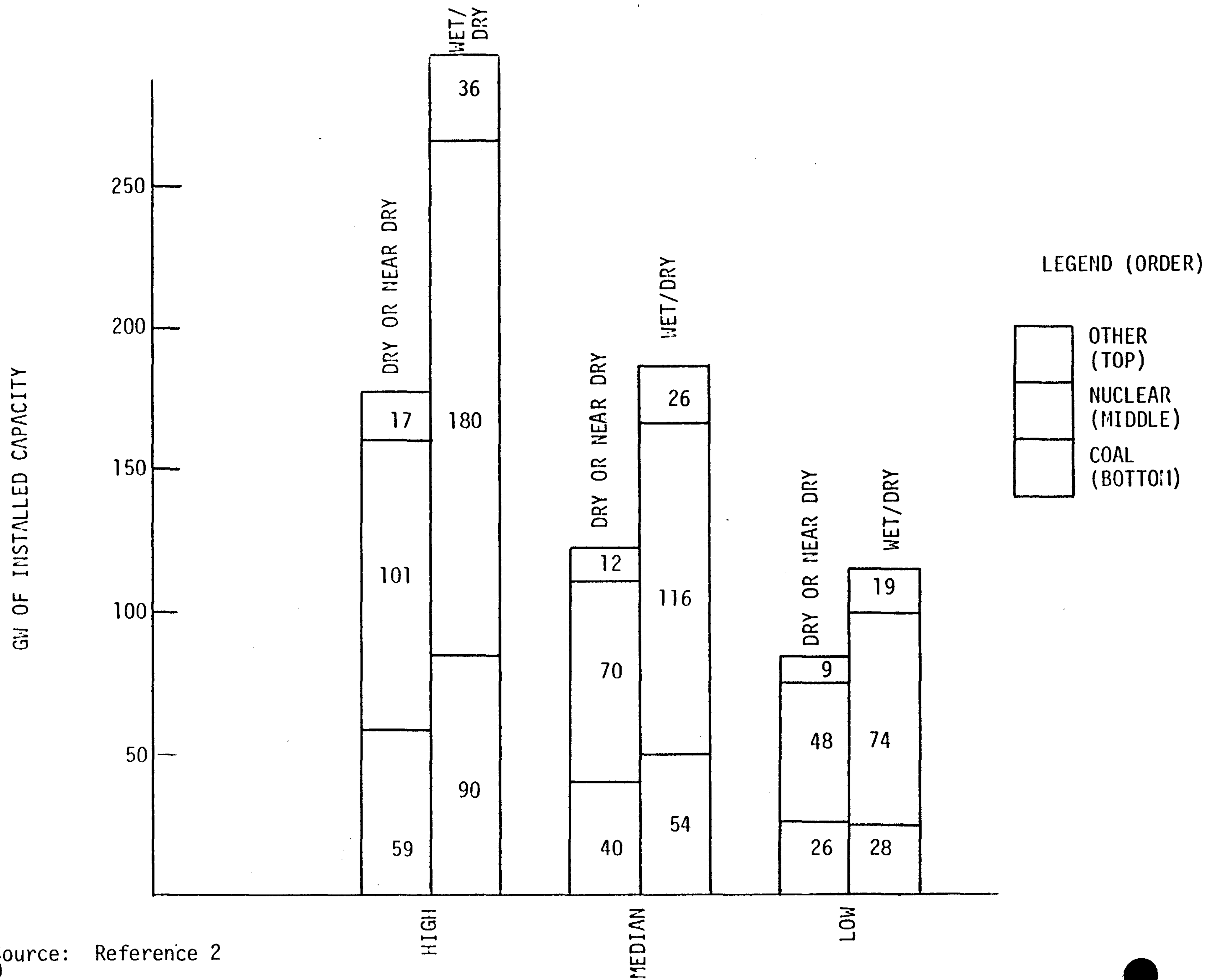
Advanced Cooling Requirements 2000-2020 (Disaggregation Based Upon Power Generation Area)



Source: Reference 2

Figure 4.2-4

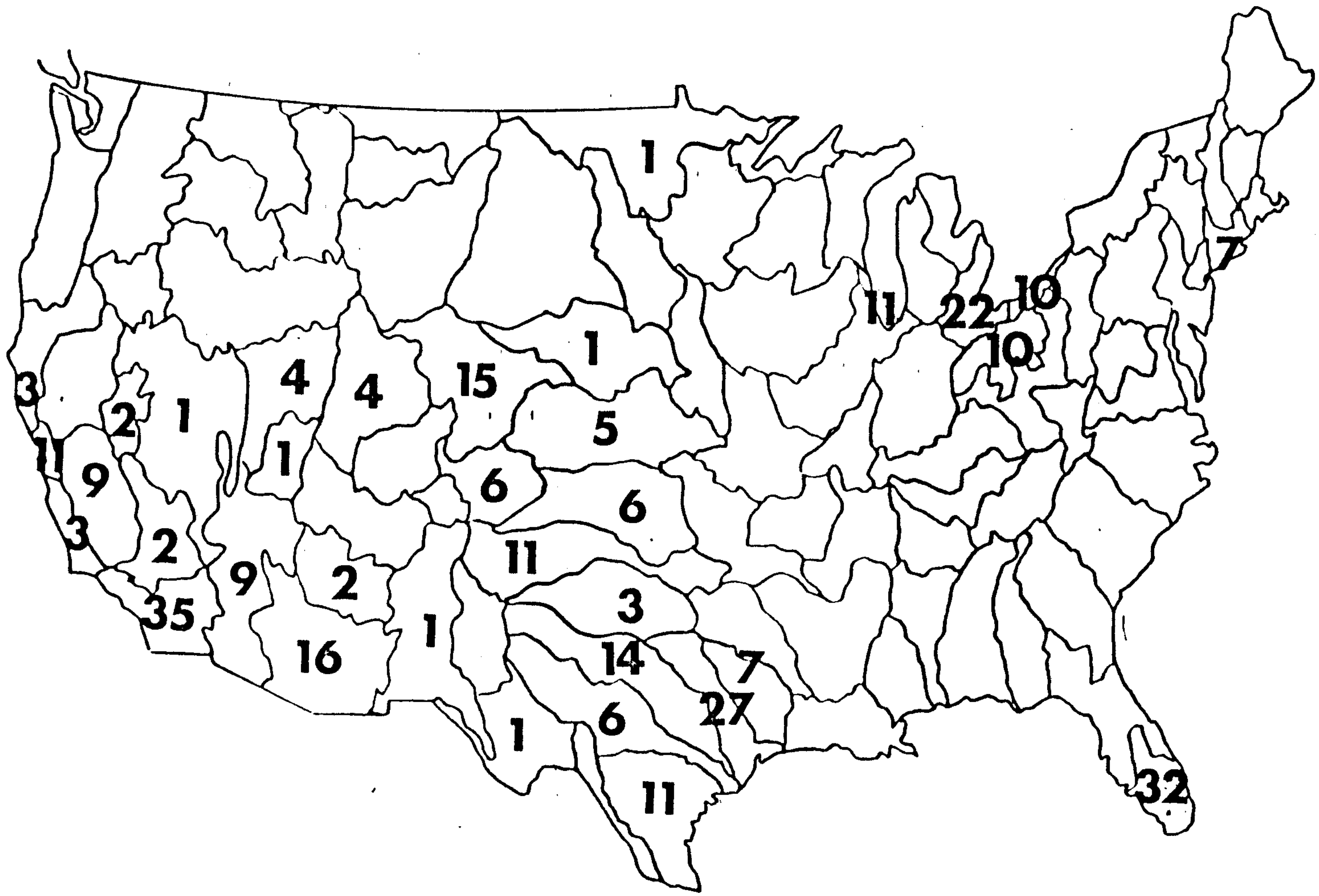
Advanced Cooling Requirements 2000-2020 (Disaggregation Based Upon Population)



Source: Reference 2

Figure 4.2-5

Areal Distribution of Forecasted Need for Advanced Cooling: Median Growth Scenario Population (GW)

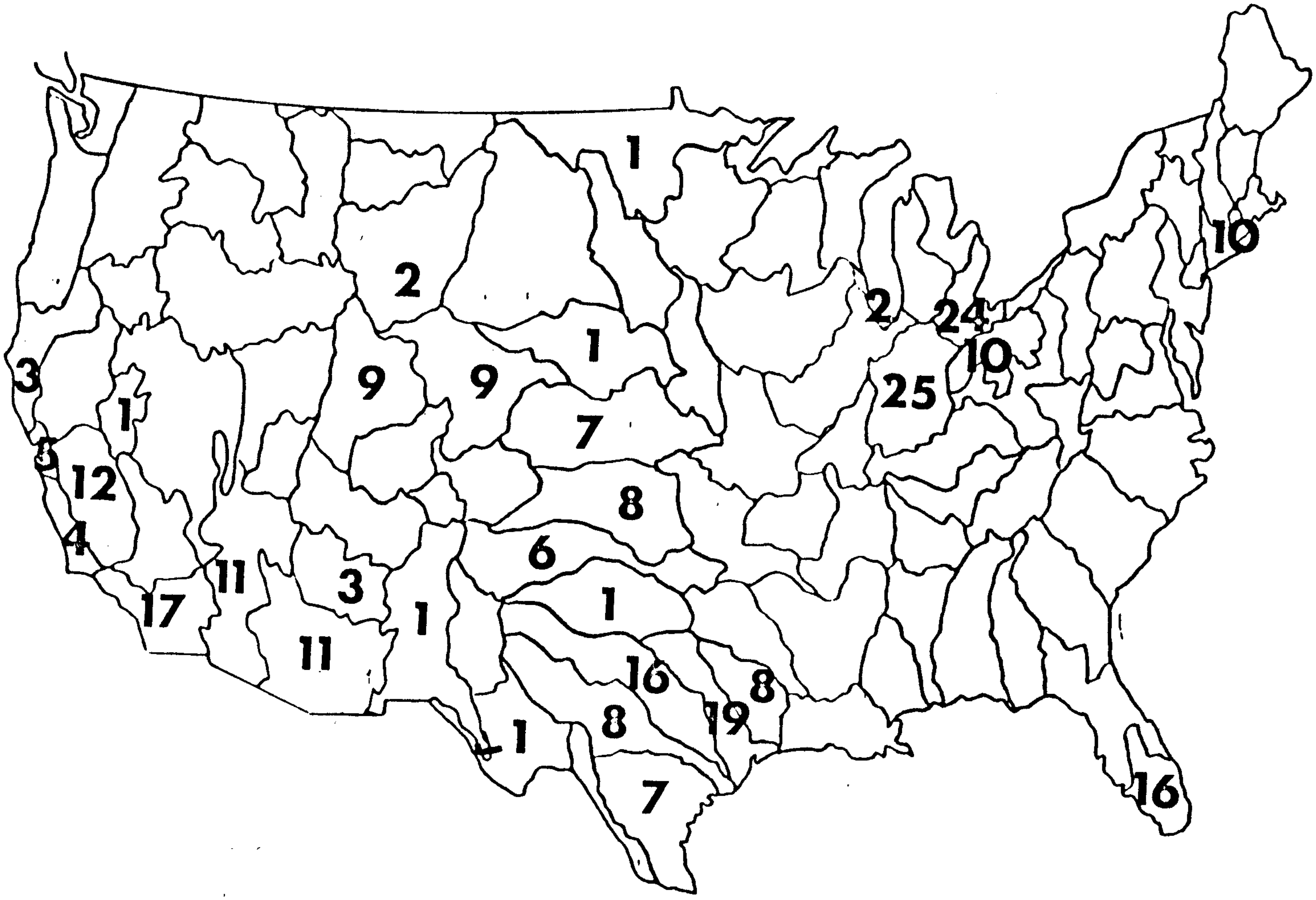


Source: Reference 2

Note: Numbers indicate GWe of capacity requiring dry or dry/wet cooling

Figure 4.2-6

Areal Distribution of Forecasted Need for Advanced Cooling:
Median Growth Scenario, Power Generation (GW)



Source: Reference 2

Note: Numbers indicate GWe of capacity requiring dry or dry/wet cooling

Table 4.2-7

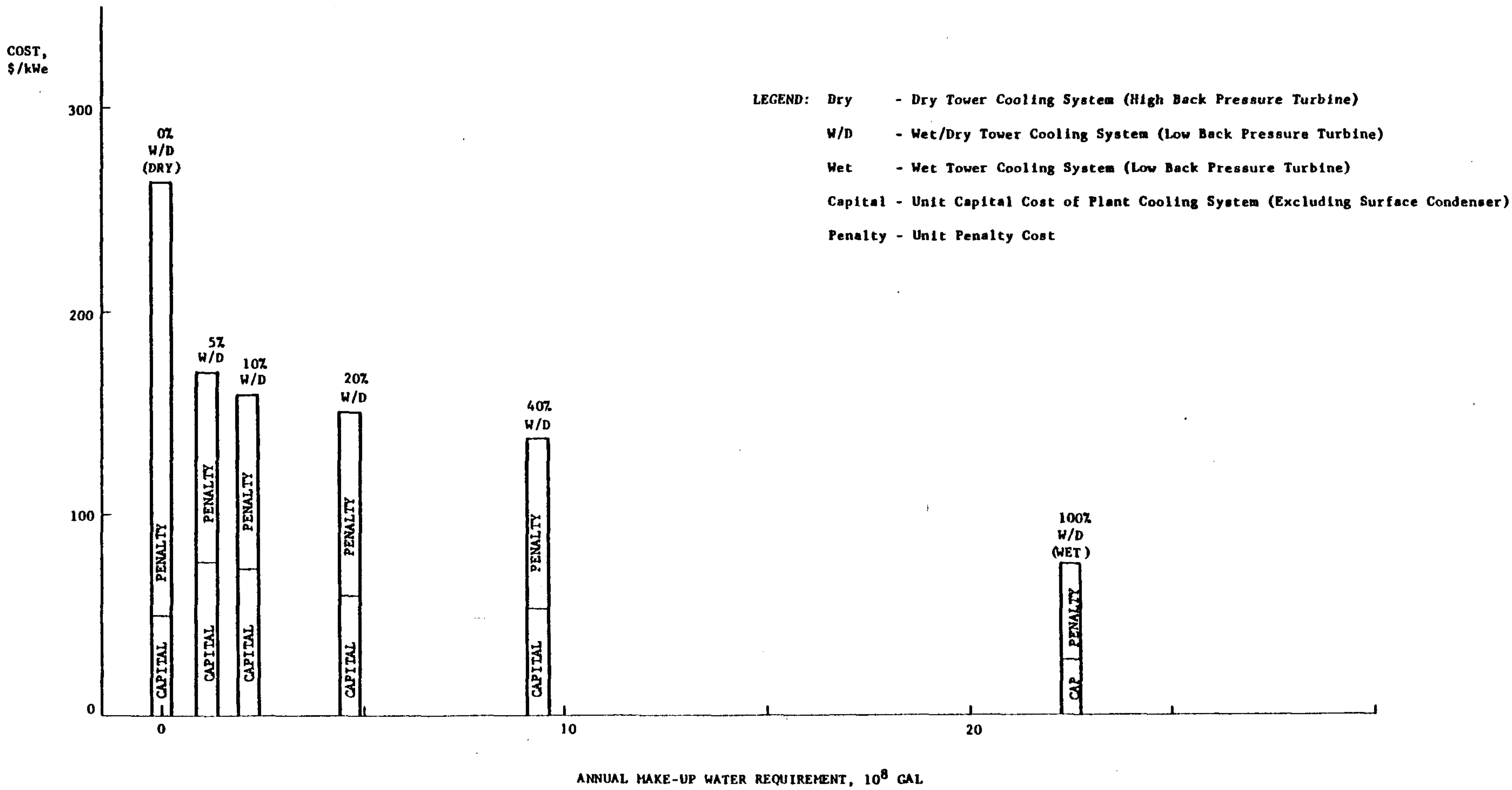
Plant Parameters for Cooling System Economic Analysis

	HTGR-SC	LWR	Coal	HTGR-GT
Rated Power - MWt*	2260	2397	1953	2000
Gross Station Heat Rate - BTU/kw-hr	8446	9760	7794	8446
Gross Electrical Output - MW	913	838	855	808
Net Thermal Efficiency	38.0	33.4	41.0	40.0
Net Electrical Output - MWe	858	800	800	800

*Output from steam generator

Figure 4.2-8

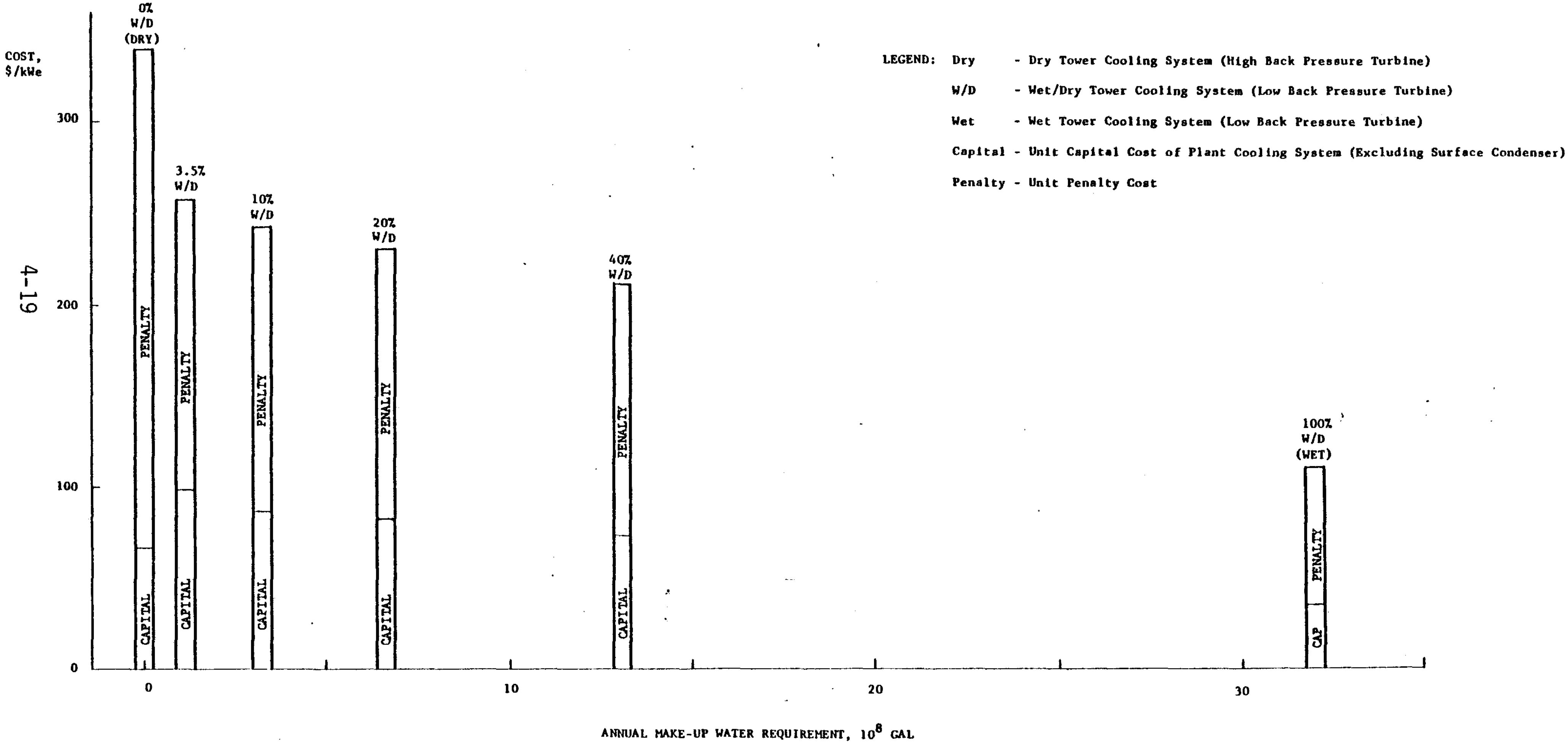
Cost Characteristics as a Function of Make-up Water Requirement for Cooling Systems Designed for an 855 MWe Fossil Plant at Modesto, California



Source: Reference 30

Figure 4.2-9

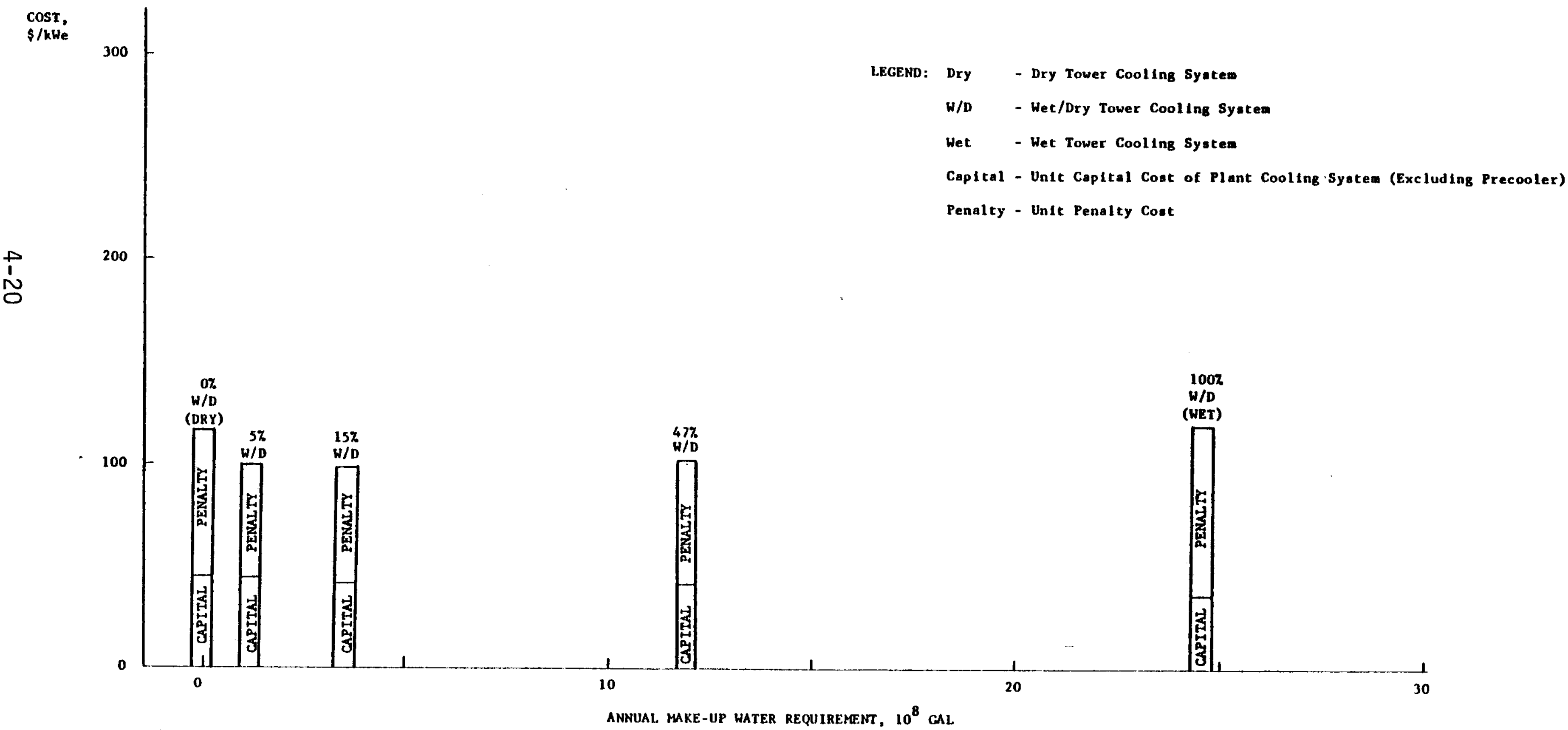
Cost Characteristics as a Function of Make-up Water Requirement for Cooling Systems Designed for an 838 MWe PWR Plant at Modesto, California



Source: Reference 30

Figure 4.2-10

Cost Characteristics as a Function of Make-up Water Requirement for Cooling Systems Designed for an 808 MWe HTGR-GT Plant at Modesto, California



Source: Reference 30

based on the economic assumptions shown in Table 4.2-11. For totally dry-cooled plants, the total evaluated cooling system costs of the fossil plant are 127% higher than for the HTGR-GT, while the LWR costs are 193% higher. These higher costs are due primarily to the high operating penalties associated with the Rankine Cycle plants with dry cooling during periods of high ambient temperature. The implication is that if any water is available for consumption, a peak-shaved, dry/wet system should be used to decrease the penalties. Figure 4.2-12 compares the relative evaluated cooling system costs of the HTGR-GT against the LWR and the coal plant as a function of water available for annual consumption. The dashed lines indicate extrapolations from the specific optimization points which are marked by "+." Optimizations were not performed in the dashed line region because dryness ratios lower than 50/50 do not conserve sufficient water to warrant their use. From Figure 4.2-12, the following conclusions can be drawn:

- All three plant types can be dry- or dry/wet-cooled. The Rankine Cycle plants must utilize a high back pressure turbine with total dry cooling in order to obtain the performance shown.

- The HTGR-GT can utilize dry or dry/wet cooling more efficiently, hence more economically, than the LWR or fossil-fired plants.

- The most economical cooling system for the HTGR-GT is a wet/dry system, while all-wet cooling is preferred for the LWR and fossil plants.

- The magnitude of the HTGR-GT advantage is a function of water availability. Generally, the less water that is available for consumption, the larger the advantage of the HTGR.

- The total evaluated cooling system costs of the HTGR-GT with wet/dry systems are relatively insensitive to cooling water availability when compared to the fossil plant and the LWR sensitivities to water availability.

In order to check the sensitivities of the above results, UE&C performed low- and high-case studies for each type of plant using the factors shown in Table 4.2-11. The results are summarized in Figures 4.2-13, 14, and 15 for the fossil, LWR, and HTGR-GT plants respectively. By comparing these figures, it can be seen that the HTGR-GT is relatively insensitive to variations in the three sensitivity variables. Table 4.2-16 summarizes these sensitivities for the fossil and LWR plants relative to the HTGR-GT for two scenarios: 100% dry and with water consumption constrained to 115 x 10^6 gal/yr.

The effects of varying individual cost parameters were also examined for each plant in Reference 30. The following conclusions can be drawn from the sensitivity analysis:

- The HTGR-GT maintains its advantage over the LWR and the fossil plant over a wide range of economic variables.

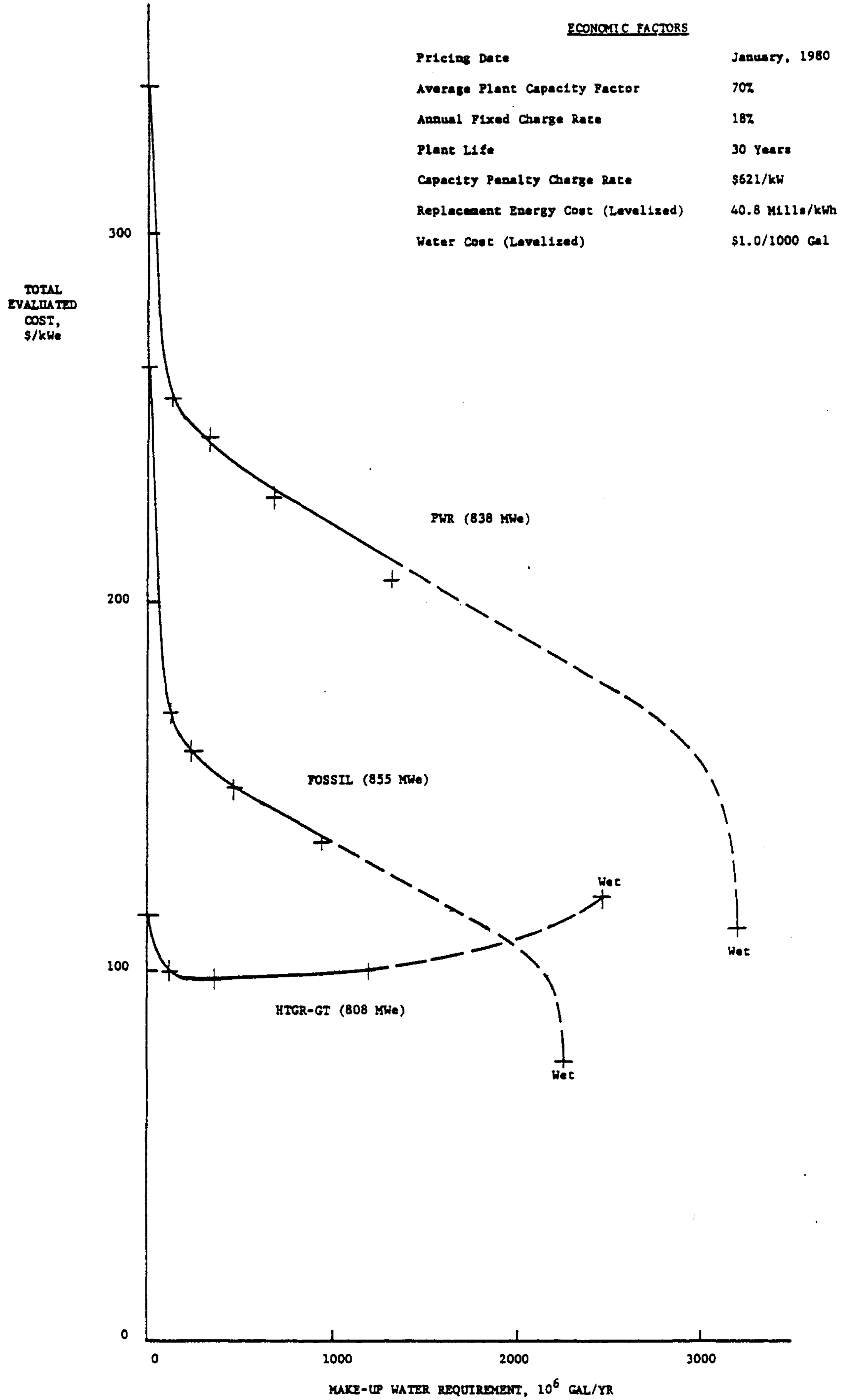
Table 4.2-11

Economic Factors for Cooling System Analysis

Pricing Date	January 1980
Average Plant Capacity Factor	70%
Annual Fixed Charge Rate	18%
Plant Book Life	30 years
Capacity Penalty Charge Rate ($/KWe)	
Base	621
Low	311
High	1242
Replacement Energy Cost (Levelized mills/kw-hr)	
Base	40.8
Low	20.4
High	122.5
Water Cost (Levelized $/1000 gal)	
Base	1.0
Low	0.5
High	2.0

Figure 4.2-12

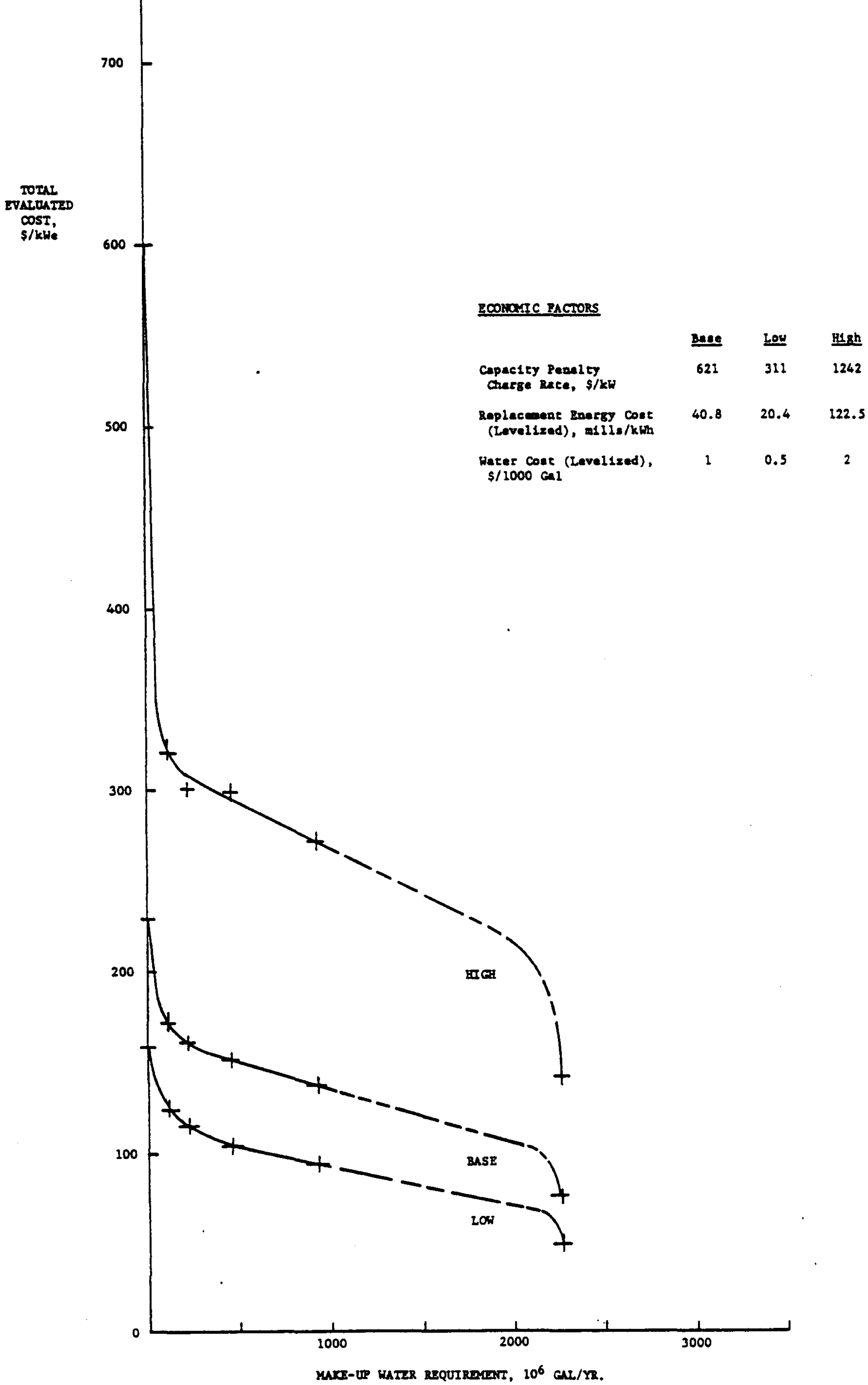
Comparison of Total Evaluated Cost Characteristics of 800 MWe (Nominal) Power Plants at Modesto, California



Source: Reference 30

Figure 4.2-13

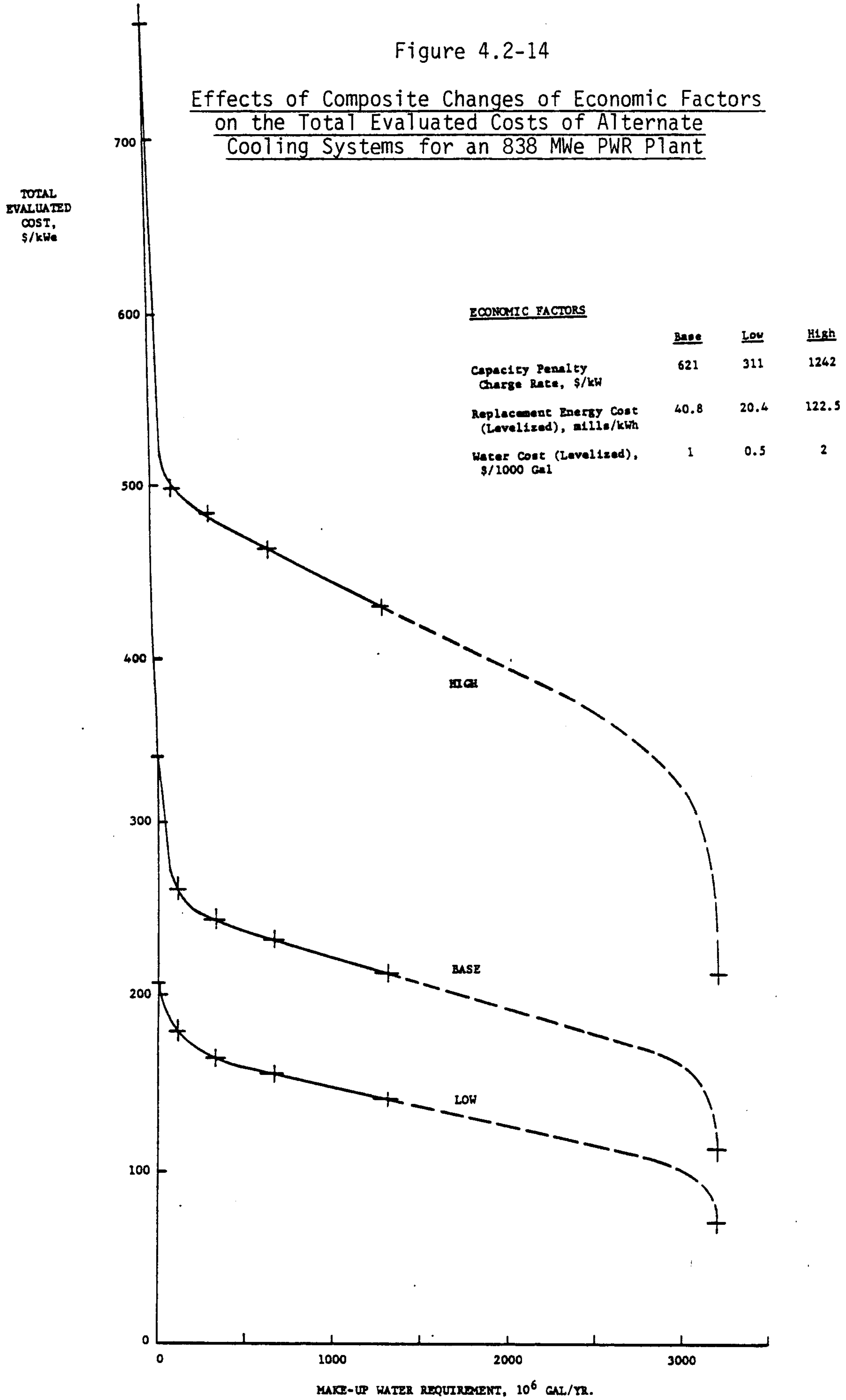
Effects of Composite Changes of Economic Factors on the Total Evaluated Costs of Alternate Cooling Systems for an 855 Fossil Plant



Source: Reference 30

Figure 4.2-14

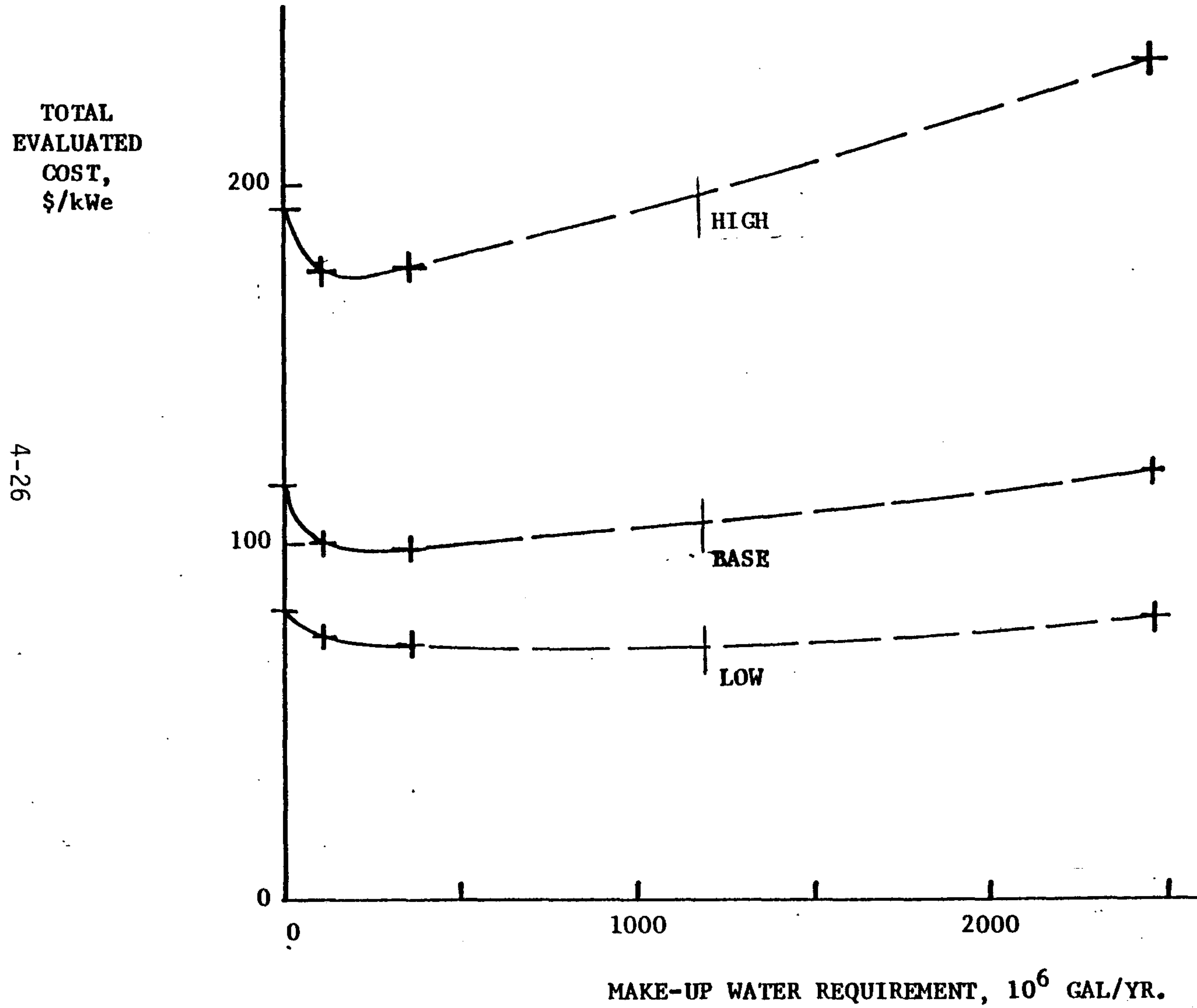
Effects of Composite Changes of Economic Factors on the Total Evaluated Costs of Alternate Cooling Systems for an 838 MWe PWR Plant



Source: Reference 30

Figure 4.2-15

Effects of Composite Changes of Economic Factors on the Total Evaluated Costs of Alternate Cooling Systems for an 808 HTGR-GT Plant



ECONOMIC FACTORS

	Base	Low	High
Capacity Penalty Charge Rate, $/kW	621	311	1242
Replacement Energy Cost (Levelized), mills/kWh	40.8	20.4	122.5
Water Cost (Levelized), $/1000 gal	1	0.5	2

Source: Reference 30

Table 4.2-16

Sensitivity Analysis Summary
Total Evaluated Cooling System Cost Differentials

100% Dry Cooling

Sensitivity Case	Fossil	LWR	HTGR-GT
Base	2.27 ($131.5M)	2.93 ($190.7M)	1.00 (Base)
Low	1.44 ($41.5M)	1.86 ($80.5M)	0.70 (-$28.3M)
High	5.52 ($420M)	6.92 ($550M)	1.68 ($63M)

Water Constraint: 115 x 10^6 gal/yr

Sensitivity Case	Fossil	LWR	HTGR-GT
Base	1.81 ($65.2M)	2.68 ($135.2M)	1.00 (Base)
Low	1.30 ($24.3M)	1.85 (68.3M)	0.73 (-$21.8M)
High	3.37 ($192M)	5.14 ($335M)	1.76 ($61.4M)

- As replacement power costs increase, the HTGR-GT becomes more economic with 100% dry cooling than with wet/dry cooling. This increases the total evaluated cooling system cost differential between the HTGR-GT and its competitors.

By combining the conventional dry or dry/wet cooling systems with the HTGR-GT, significant cost savings associated with cooling system performance can result. Because this plant is still in the conceptual design stage with resultant uncertainties in the capital cost estimates, it is not possible to draw definite conclusions as to the overall cost effectiveness of utilizing the HTGR-GT in areas where dry cooling technology will be required. However, the differentials of the evaluated cooling system costs given in Table 4.2-16 do provide a measure of the premium that a utility should be willing to pay for the HTGR-GT in areas where water constraints will force the use of dry or dry/wet cooling. Section 6.2 examines these cooling system economic results in the context of total HTGR-GT power costs.

In addition to the conventional forms of dry or dry/wet cooling technology that were examined in this section, an alternate dry cooling technology is currently under development which may result in a significant reduction of the penalties associated with dry cooling. Under sponsorship from the Electric Power Research Institute (EPRI), an ammonia phase-change system is being developed which rejects heat from the steam condenser to the atmosphere through modified dry coolng towers. A pilot system was constructed by Union Carbide to predict component performance. Based on the successful operation of this system, a 10 MWe system is currently being installed at the Kern Station of Pacific Gas and Electric Company and is scheduled for operation in 1982. Figure 4.2-17 from Reference 31 shows projections of substantial savings over the conventional dry-cooling systems examined in this study. The economic and environmental parameters used to generate Figure 4.2-17 are substantially different than those used in this study; therefore, the results are not directly comparable. However, the results of the work performed so far are promising, and the successful commercialization and use of this ammonia phase-change system with economic characteristics similar to those shown in Figure 4.2-17 will have significant impact on the economic performance of the plants evaluated in this study.

4.3 OTHER SITING CONSIDERATIONS

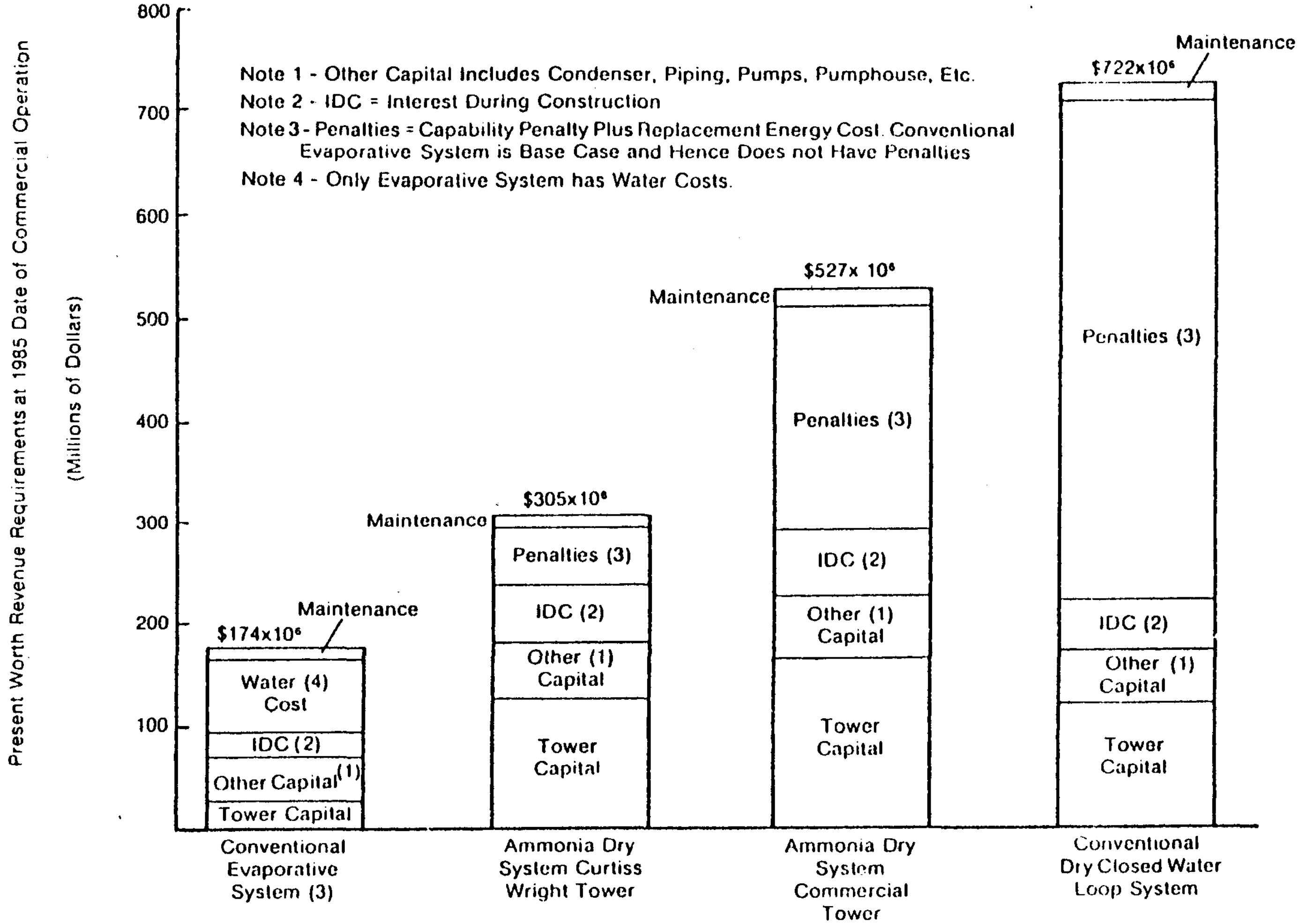
As shown in Section 4.2, the HTGR offers advantages over its competition for siting in areas where water is not readily available for consumption. This section will examine additional factors which will affect siting of an HTGR, specifically its radiological and seismic characteristics, and the institutional barriers to nuclear siting as they apply to the HTGR.

4.3.1 Radiological

This section will present a comparative analysis that attempts to identify the envelope of site characteristics which would meet the radiological impact objectives necessary to the siting of an HTGR. For this analysis, Appendix I of 10CFR50, which specifies the radiological impact objectives for the LWR, was assumed as the applicable

Figure 4.2-17

Comparison of Cooling System Present Worth Revenue Requirements for an 1140 MWe Plant



Source: Reference 31

regulatory guideline for the HTGR. This analysis applies specifically to the large (3000 MWt) HTGR steam cycle design, but the results are comparable to those that would be obtained for the Gas Turbine and Reformer systems.

Appendix I of 10CFR50 specifies that each reactor shall be designed such that the maximum calculated radiation dose to an individual in the unrestricted area around the plant shall not exceed the following values per reactor per year:

Liquid Effluent

• Whole body dose	3 mrem
• Dose to any organ	10 mrem

Gaseous Effluent

• Gamma air dose	10 mrad
• Beta air dose	20 mrad
• Skin dose	15 mrem
• Whole body dose	5 mrem

Airborne Radioactive Iodine and Particulates

o Dose to any organ	15 mrem

Other regulations such as 10CFR40 and 10CFR20 also affect the radiological design of nuclear power plants, but generally compliance with 10CFR50 assures compliance with all others.

The two groups of factors which determine if a particular plant will meet the above guidelines at a particular site are (1) Plant Performance Characteristics and (2) Site-Dependent Characteristics. The designer must take the site-dependent characteristics into account in order to design the radwaste systems such that the plant performance characteristics will result in releases that comply with the above criteria. One of the most important site-dependent characteristics that affect gaseous releases of radioactivity is the atmosphere's ability to disperse and dilute the releases. A quantitative measure of dilution is the annual average atmospheric dispersion factor X/Q where:

- X is the concentration of the diluted radioactive gaseous releases at a given point of interest in units of mass/volume

- Q is the rate of radiological releases at the source in units of mass/time

The factor X/Q is estimated by atmospheric diffusion models and will vary from approximately 2×10^{-6} to 2×10^{-5} sec/m^3 at 500 m for ground releases, and 1×10^{-9} to 2×10^{-7} sec/m^3 for stack releases at 500 m.

The other site-dependent characteristic influencing radiological dose is the pathway through which the radionuclides are transported to man. This analysis will only consider the air pathways as the current reference design for all HTGR systems is based on zero liquid releases. Generally, the air pathways considered include:

- Air immersion
- External exposure to deposited materials
- Inhalation and transpiration
- Ingestion of food crops
- Ingestion of animal products

Doses are calculated for the whole body and its significant organs. A limiting pathway, i.e., the worst case, is then selected and analyzed.

Reference 11 compared a large HTGR steam cycle plant with HEU/Th fuel to both BWRs and PWRs. Table 4.3-1, which is taken from Reference 11, shows the strength of various radionuclides released from various plants according to their Safety Analysis Reports. The Fulton Station HTGR, which was used in the study, did release some liquid effluents. These will be eliminated in future HTGRs. Because the plants listed are of differing sizes, Table 4.3-2 normalizes the releases to 1160 MWe, which was the size of the Fulton unit, for direct comparison purposes. It can be seen from this table that the HTGR generally exhibits a two-orders-of-magnitude reduction in the amount of radionuclides released in gaseous form. This is due to the design of the HTGR fuel, which is composed of individual coated particles. The coatings of these particles act as individual pressure vessels which contain the fission products under extreme pressure and temperature conditions.

Reference 11 then calculated the dose rates for each limiting pathway and determined the estimated annual dose to an individual and his significant organs for these pathways as a function of the X/Q at the location where a person may live. Figure 4.3-3 shows the whole body dose (mrem/yr) from gaseous effluents to the atmosphere. Figure 4.3-4 shows the adult skin dose and Figure 4.3-5 shows the thyroid dose to an infant drinking milk. It can be seen from these figures that the HTGR can be sited in areas with relatively unfavorable atmospheric dispersion factors; therefore, it does not require tall stacks for gaseous releases.

General conclusions that can be drawn on the above information and from Reference 11 analyses are:

- The HTGR and the LWR can be located over a relatively wide range of site conditions and still meet the radiological impact objectives specified in Appendix I of 10CFR50.
- For gaseous releases, the LWR usually requires about two orders of magnitude more atmospheric dilution than the HTGR. Because of the additional dilution required, the LWR will require additional radwaste equipment in the plant design.

Table 4.3-1

ESTIMATE OF ANNUAL RELEASE OF RADIOACTIVITY IN EFFLUENTS (AS EXTRACTED FROM FINAL ENVIRONMENTAL STATEMENT)

			Effluents to Atmosphere (Ci/yr)						Liquid Effluents (Ci/yr)									
Plant Name	Vendor & Reactor Type	Location	I-131	Kr-85	Kr-88	Xe-133	Xe-135	Xe-138	Co-58	Co-60	Sr-89	Sr-90	I-131	Cs-134	Cs-137	H-3	Net MW(e) Unit
Fulton	GA-HTGR	Fulton, Pa.	7.9×10^{-7}	(a)	14	9	7	2	*	*	.0001	.0009	*	.018	.036	21	1160
Grand Gulf 1&2	GE-BWR	Port Gibson, Miss.	.037	880	55	3400	420	240	.11	.013	.11	.006	.16	.91	.58	20	1250
Skagit 1&2	GE-BWR	Sedro Wooley, Wash.	.028	840	49	3254	418	230	No Planned Releases of Radioactive Liquids								1269
Clinton 1&2	GE-BWR	Clinton, Ill.	.27	660	47	3200	420	230	.0091	.0011	.0053	.00027	.0098	.0081	.0041	20	950
River Bend 1&2	GE-BWR	St. Francisville, La.	.08	664	11	2357	367	57	.013	.0015	.0098	.0005	.025	.0097	.0065	20	940
Nine Mile Point 2	GE-BWR	Scriba, N.Y.	.58	760	450	18,400	290	280	.015	.002	.0082	.00051	.042	.0064	.0042	20	1100
Susquehanna 1&2	GE-BWR	Berwick, Pa.	.018	740	72	1400	260	77	.040	*	.028	.0014	.057	.023	.017	20	1052
Byron 1&2	W-PWR	Byron, Ill.	.05	988	24	2357	40	6	.00028	.00004	.00001	*	.062	.0059	.0046	350	1120
Braidwood 1&2	W-PWR	Braidwood, Ill.	.05	988	24	2357	40	6	.00028	.00004	.00001	*	.062	.0059	.0046	350	1120
Shearon Harris 1&2	W-PWR	Newhill, N.C.	.043	795	28	2500	46	6	.00021	.00003	*	*	.049	.0058	.0045	350	900
South Texas 1&2	W-PWR	Palacios, Tex.	.087	1050	32	340	26	8	.0045	.0088	*	*	.075	.017	.025	350	1250
Comanche Peak 1&2	W-PWR	Glen Rose, Tex.	.044	970	22	280	26	6	.0021	.00028	.00008	*	.18	.015	.0097	350	1150
Catawba 1&2	W-PWR	Lake Wylie, S.C.	.094	970	20	290	24	6	.0018	.00023	.00008	*	.20	.017	.12	350	1180
Pebble Springs 1&2	B&W-PWR	Arlington, Ore.	.049	1030	34	3440	53	8	.001	.00013	*	*	.045	.0043	.0012	160	1260
North Anna 3&4	B&W-PWR	Mineral, Va.	.018	738	16	931	27	4	.00037	.000012	.000014	*	.75	.0048	.0034	1000	938
Surry 3&4	B&W-PWR	Gravel Neck, Va.	.05	738	16	912	27	4	.00028	.00004	*	*	.023	.013	.0085	685	900
WPPSS 4	B&W-PWR	Richland, Wa.	.032	1000	23	840	35	5	.00016	.00002	*	*	.005	.024	.015	350	1250
Greenwood 2&3	B&W-PWR	St. Clair Co., Mich.	.019	1000	24	2800	41	6	.00012	.00002	*	*	.011	.0027	.0018	350	1208
Pilgrim 2	CE-PWR	Plymouth, Mass.	.16	1000	32	2970	54	8	.052	.015	.0021	.00006	1.3	.10	.15	350	1180
Waterford 3	CE-PWR	Taft, La.	.11	988	26	3500	43	6	.0025	.000082	.00013	.000005	.29	1.6	1.3	1000	1165
San Onofre 2&3	CE-PWR	San Clemente, Ca.	.29	932	24	2473	38	6	.00096	.0003	.00037	.000013	2.2	.42	.36	1000	1140
WPPSS 3&5	CE-PWR	Satsop, Wa.	.017	1100	28	290	31	8	.0046	.00087	.00017	*	.016	.019	.012	350	1240

(a) HTGR plant design has the option of either recycling all of the Kr-85 through the helium purification system or releasing Kr-85 intermittently to the atmosphere under favorable meteorological conditions. If recycled, there will be no release of Kr-85 to the atmosphere. If released, the rate of release is estimated to be 4185 Ci/yr.

* Too low to be included.

Source: Reference 11

Table 4.3-2

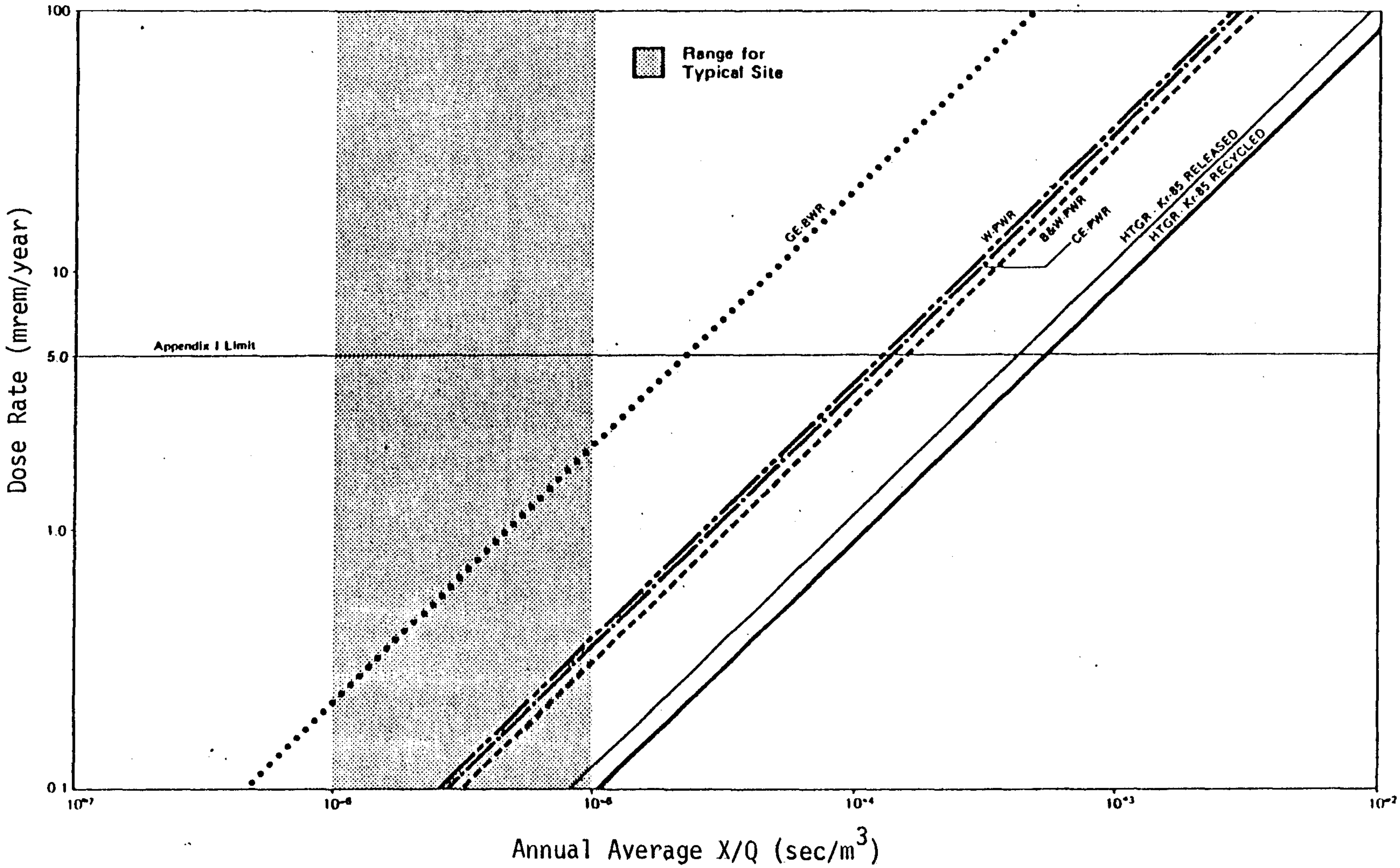
ESTIMATE OF ANNUAL RELEASE OF RADIOACTIVITY IN EFFLUENTS (NORMALIZED TO 1160 MWe)

Plant Name	Vendor & Reactor Type	Effluents to Atmosphere (Ci/yr) I-131	Kr-85	Kr-88	Xe-133	Xe-135	Xe-138	Liquid Effluents (Ci/yr) Co-58	Co-60	Sr-89	Sr-90	I-131	Cs-134	Cs-137	H-3	Normalizing Factor
Fulton	GA-HTGR	7.9×10^{-7}	(a)	14	9	7	2	*	*	.0001	.0009	*	.018	.036	21	1.00
Grand Gulf 1&2	GE-BWR	.034	820	51	3200	390	220	.10	.012	.10	.006	.15	.84	.54	19	0.928
Skagit 1&2	GE-BWR	.031	920	53	3500	460	250	No planned releases of liquids containing radioactivity**								1.09
Clinton 1&2	GE-BWR	.33**	810	57	3900	510	280	.0111	.0013	.0065	.00033	.012	.0099	.0050	24	1.22
River Bend 1&2	GE-BWR	.10	820	14	2900	450	70	.015	.0018	.012	.00062	.031	.012	.0077	25	1.23
Nine Mile Point 2	GE-BWR	.61**	800	470	19300**	310	290	.016	.0021	.0086	.00054	.044	.0067	.0044	21	1.05
Susquehanna 1&2	GE-BWR	.020	840	500	1500	310	85	.017	*	.025	.0015	.063	.025	.018	22	1.10
"Representative"	GE-BWR	.046	840	190	3000	410	200	.032	.0034	.030	.0018	.060	.18	.12	22	
Byron 1&2	W-PWR	.05	1000	25	2500	42	6	.00029	.00004	.00001	*	.065	.0062	.0048	360	1.04
Braidwood 1&2	W-PWR	.05	1000	25	2500	42	6	.00029	.00004	.00001	*	.065	.0062	.0048	360	1.04
Shearon Harris 1&2	W-PWR	.055	1000	110	3200	59	8	.00027	.00004	*	*	.063	.0075	.0055	450	1.29
South Texas 1&2	W-PWR	.081	970	30	320	32	7	.0042	.0082	*	*	.070	.016	.023	330	0.928
Comanche Peak 1&2	W-PWR	.044	970	22	280	26	6	.0021	.00028	.00008	*	.18	.015	.0097	350	1.00
Catawba 1&2	W-PWR	.092	950	20	290	24	6	.0018	.00023	.00008	*	.20	.17	.12	340	0.983
"Representative"	W-PWR	.062	980	39	1500	38	7	.0015	.00015	.00003	*	.11	.037	.028	370	
Pebble Springs 1&2	B&W-PWR	.045	950	31	3200	53	7	.0009	.00012	*	*	.041	.0040	.0011	150	0.921
North Anna 3&4	B&W-PWR	.022	920	20	1200	33	5	.00046	.000015	.000015	*	.93	.0060	.0042	1200	1.24
Surry 3&4	B&W-PWR	.06	950	21	1200	35	5	.00036	.0005	*	*	.029	.017	.011	450	1.29
WPPSS 4	B&W-PWR	.03	930	21	780	32	5	.00015	.000019	*	*	.0046	.022	.014	330	0.928
Greenwood 2&3	B&W-PWR	.018	960	23	2700	39	6	.00012	.00002	*	*	.011	.0026	.0017	340	0.96
"Representative"	B&W-PWR	.035	940	23	1800	38	5	.00040	.00016	*	*	.20	.010	.006	490	
Pilgrim 2	CE-PWR	.16	980	31	2900	53	8	.050	.015	.0021	.000059	1.3	.098	.15	340	0.983
Waterford 3	CE-PWR	.11	980	26	3500	43	6	.0025	.000082	.00013	.000005	.29	1.6	1.3	1000	0.996
San Onofre 2&3	CE-PWR	.30	950	24	2500	39	6	.00098	.00031	.00038	.000013	2.2	.43	.37	1020	1.02
WPPSS 3&5	CE-PWR	.016	1030	26	270	29	8	.0043	.00081	.00016	*	.015	.018	.011	330	0.935
"Representative"	CE-PWR	.15	990	27	2300	41	7	.014	.00041	.00069	.000019	.95	.54	.46	670	

(a)Plant design calls for recycling all of the Kr-85 to the helium coolant. If it is released, the total estimated Kr-85 would be 4185 Ci/yr.
*Too low to be included
**Not included in average

Source: Reference 11

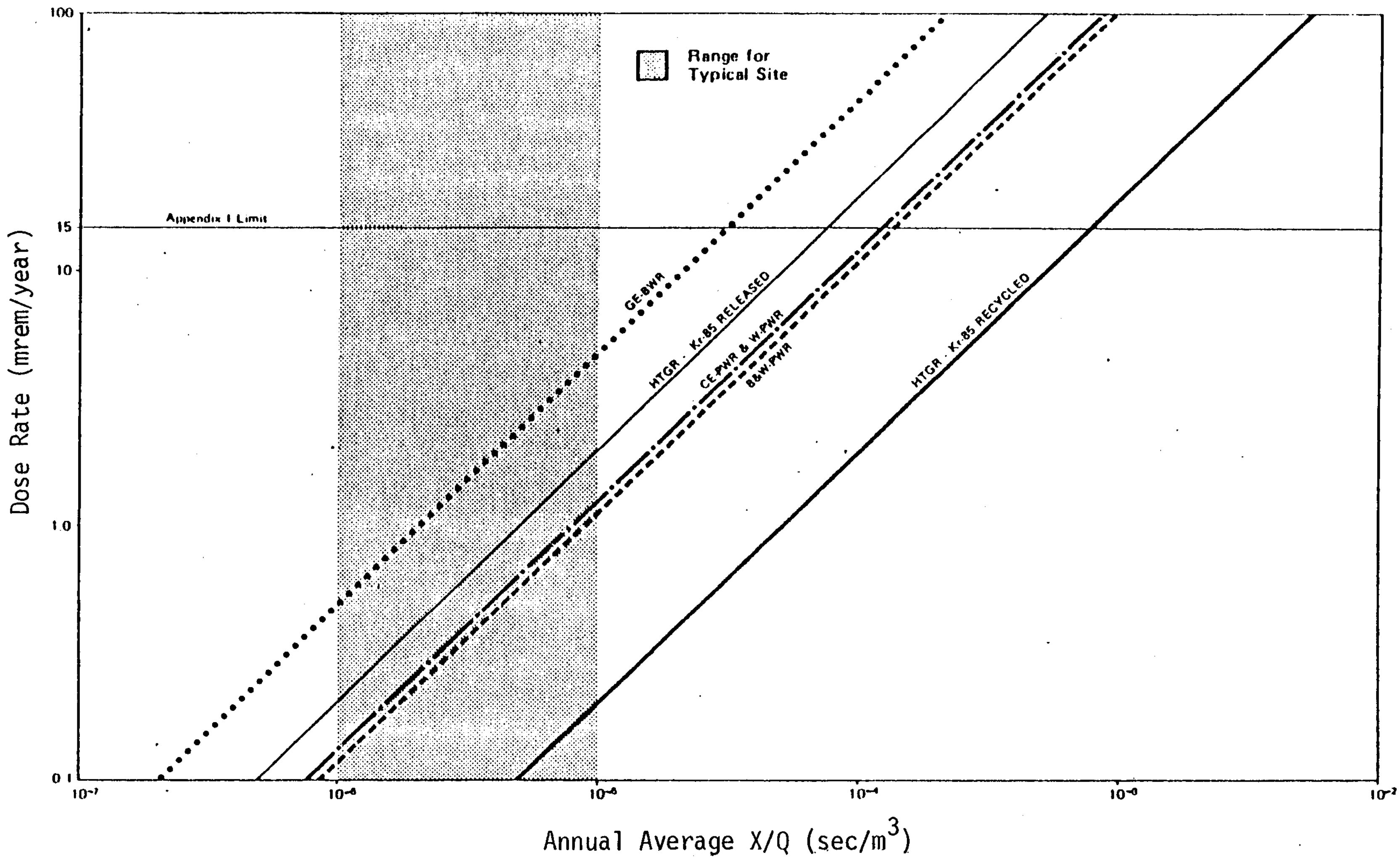
Figure 4.3-3



WHOLE BODY DOSE FROM GASEOUS EFFLUENTS TO THE ATMOSPHERE

Source: Reference 11

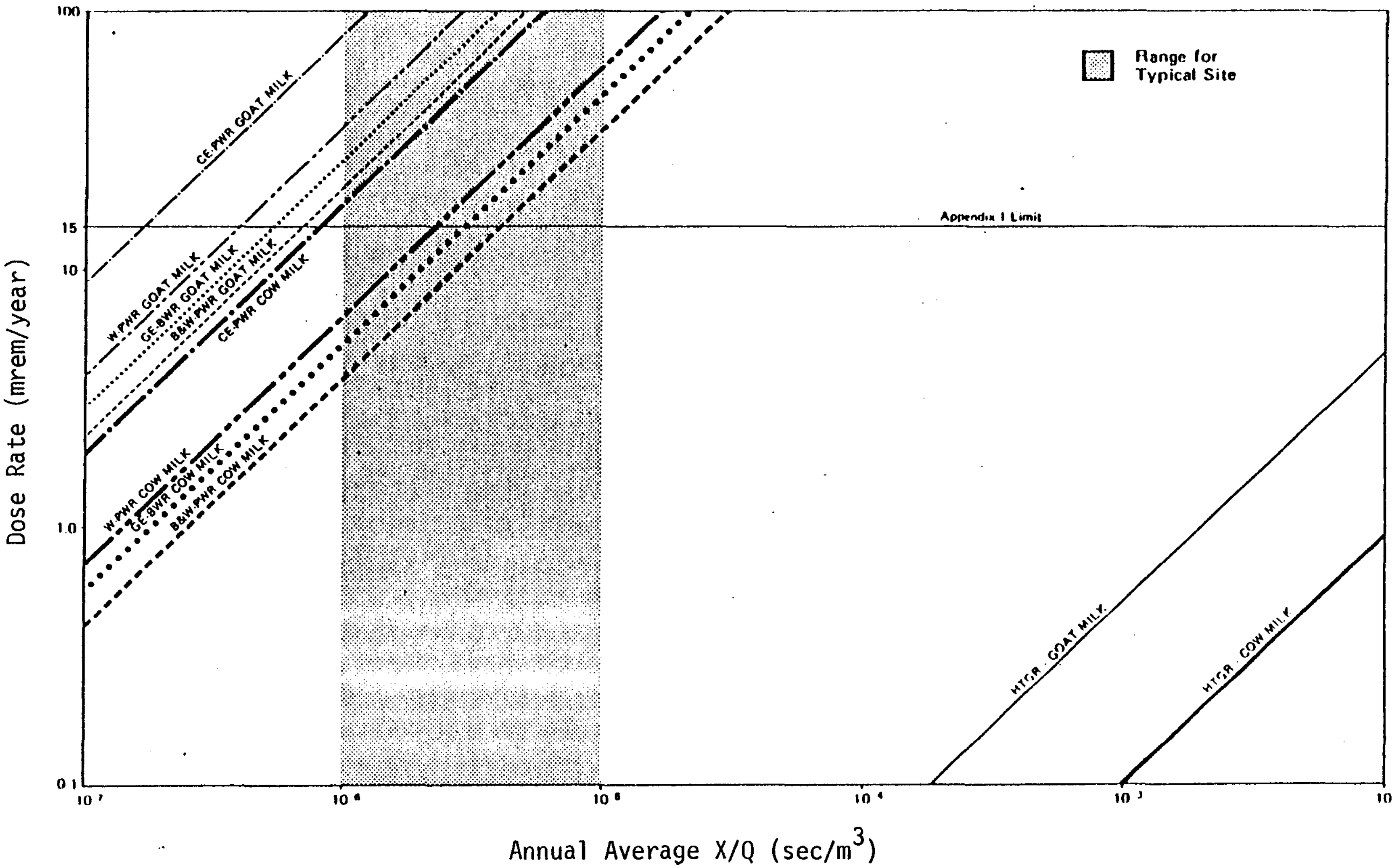
Figure 4.3-4



SKIN DOSE FROM GASEOUS EFFLUENTS TO THE ATMOSPHERE

Source: Reference 11

Figure 4.3-5



THYROID DOSE RATE TO AN INFANT FROM INGESTING MILK CONTAINING I-131

Source: Reference 11

- For the HTGR, the limiting radiological impact for gaseous release is the whole body dose from immersion in a gaseous cloud. For the LWR, it is the thyroid dose from the iodine-milk-infant pathway.

- From the standpoint of radiological impact, the HTGR in general has greater flexibility in siting than the LWR.

4.3.2 Geological

According to the requirements set forth in the GCRA Functional Specification for the HTGR-SC design, the maximum horizontal ground accelerations are .15g OBE, .3g SSE for a hard rock site, and .2g OBE, .4g SSE for a firm soil site. For the HTGR-GT, the selected values are .15g OBE and .3g SSE for all types of soil. As a reference, a major LWR supplier uses .25g as its reference SSE acceleration. To quantify the areas of the U.S. market which would be satisfied by these geological design criteria, GCRA commissioned studies by Dames & Moore and URS/John Blume & Associates.

The purpose of the Dames & Moore Report (Reference 12) was to make a preliminary assessment of the areas within the contiguous U.S. having sufficiently suitable subsurface conditions to permit economical design and construction of HTGR foundations. Maps were prepared showing zones of geologically similar conditions. Within these zones, approximate percentages of potential sites were determined having four different soil bearing pressure categories at an assumed foundation depth of forty feet. The GCRA reference static allowable bearing capacity is 10 $kips/ft^2$ at a depth of forty feet. This value is important in reference plant design because as the allowable bearing capacity decreases, the size of the foundations must increase to distribute the structure weight over a larger area and, therefore, the design is necessarily more expensive.

The four foundation condition categories were defined as:

Category A: Where bearing pressure of 20 to 30 kips per square foot (ksf) or more may be appropriate

Category B: Where bearing pressures on the order of 10 ksf may be appropriate

Category C: Where site improvement methods will render sites suitable for designs using bearing pressures in the range of 10 to 20 ksf

Category D: Where prospects for upgrading to conditions commensurate with design for 10 ksf are technically or economically unfeasible, i.e., costs of site improvements will be greater than $50 million

The results of the study are summarized in Table 4.3-6. The physiographic provinces are shown in Figure 4.3-7. These results show

Table 4.3-6

SUMMARY OF RESULTS

Physiographic Province	Estimated Percentage of Area in Different Categories A	B	C	D
Pacific Mountain Division				
Puget-Willamette Lowland				
Washington	50	20	20	10
Oregon	<5	10	65	20
Cascade, Klamath, Sierra Nevada Ranges	90	5	5	<1
Central Valley of California	10	30	55	<5
Coast Ranges	75	10	10	5
Rocky Mountain Division				
Northern Rocky Mountains	90	5	5	<1
Blue Mountains	80	10	10	<1
Middle Rocky Mountains	90	5	5	<1
Southern Rocky Mountains	80	10	10	<1
Wyoming Basin	80	10	10	<1
Intermontane Division				
Columbia Basin	80	5	10	5
Harney-Owyhee Broken Lands	80	10	10	<1
Snake River Lowland	50	25	25	<1
Basin and Range				
Arizona	5	85	5	5
California	80	5	10	<5
Nevada	60	10	15	15
Utah	20	10	20	50
Colorado River Plateau	80	10	10	<1
Upper Gila Mountains	80	10	10	<1
Interior Division				
Central Lowlands				
Dakota-Minnesota Drift and Lake Bed Flats	10	20	60	10
North-central Lake-Swamp Moraine Plains (east)	<1	25	70	5
(west)	10	25	45	20
Southwest Wisconsin Hills	70	20	10	<1
Middle Western Upland Plain	30	40	30	<1
Mid-Continent Plains and Escarpments	40	35	20	<5
East-central Drift and Lake Bed Flats	10	50	40	<1
Interior Low Plateaus	40	30	20	10

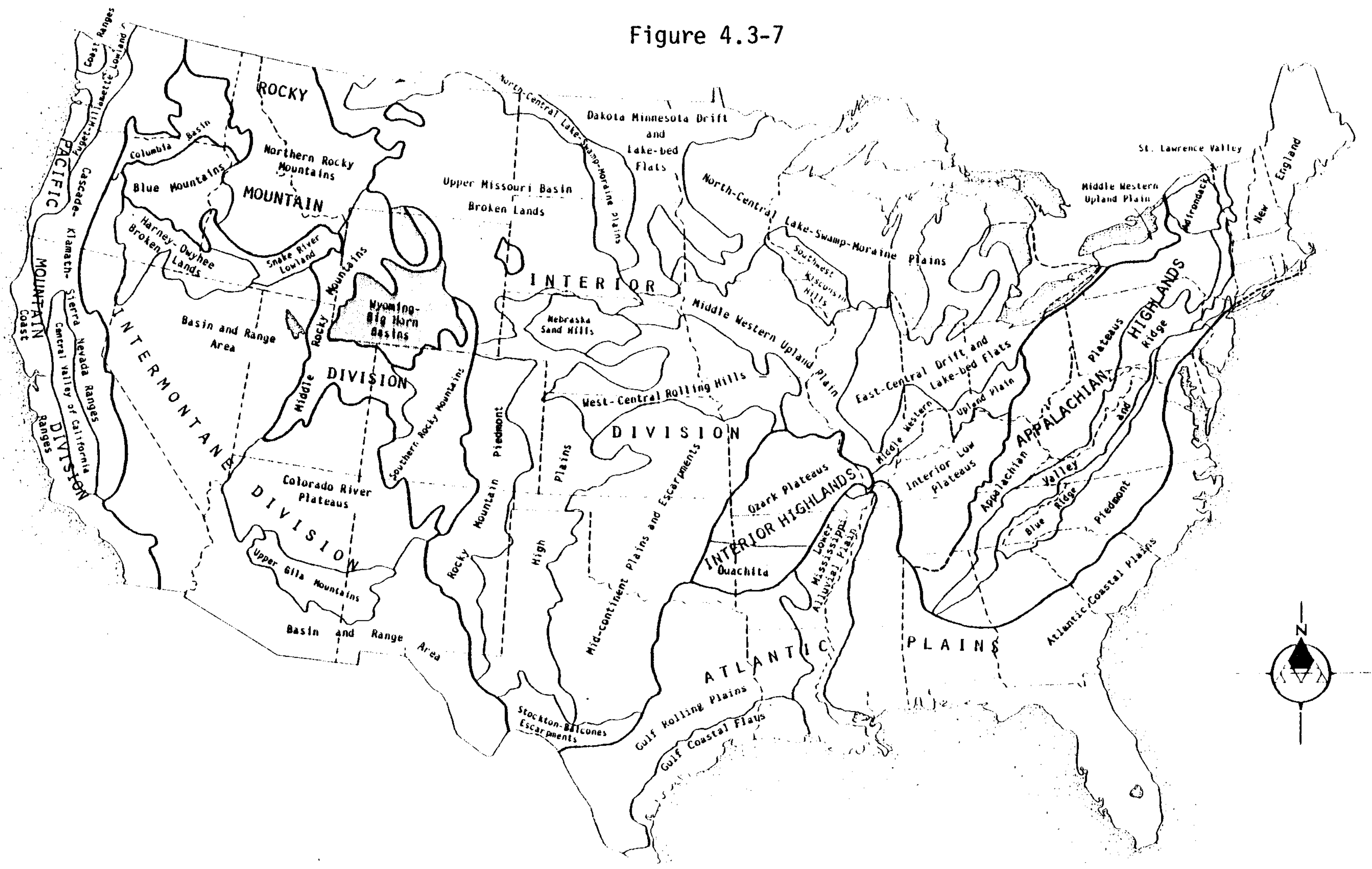
Table 4.3-6

(Continued)

Physiographic Province	Estimated Percentage of Area in Different Categories A	B	C	D
Interior Division (continued)				
Great Plains				
Upper Missouri Basin				
Broken Lands	70	15	15	<1
Nebraska Sand Hills	0	20	50	30
West-central Rolling Hills	20	30	45	<5
High Plains	20	55	20	<5
Rocky Mountain Piedmont	80	10	10	<1
Stockton-Balcones Escarpments	25	45	25	<5
Appalachian Highlands				
Piedmont	30	40	25	5
Blue Ridge	40	30	25	5
Valley and Ridge	55	20	20	<5
Appalachian Plateaus	40	40	20	<1
Adirondack	80	10	10	<1
New England	70	15	15	<1
St. Lawrence Valley	25	30	35	10
Interior Highlands				
Ozark Plateaus	60	20	20	<1
Ouchita Plateaus	40	30	20	20
Atlantic Plains				
Atlantic Coastal Plain	5	20	40	35
Gulf Rolling Plains	10	60	30	<1
Gulf Coastal Flats	0	40	55	5
Lower Mississippi Alluvial Plain	0	5	50	45

Source: Reference 12

Figure 4.3-7



REFERENCES: U.S.G.S. THE NATIONAL ATLAS OF THE
UNITED STATES OF AMERICA, 1970, SHEETS 60 & 61.

0 100 200 300 400 miles
0 200 400 600 kilometers

PHYSIOGRAPHIC PROVINCES OF THE UNITED STATES

DAMES & MOORE

PLATE 1

Source: Reference 12

that for the reference design static bearing capacity of 10 ksf, the HTGR will be siteable in most areas and will not be unduly restricted.

The URS/Blume study (Reference 13) attempted to define safe shutdown earthquake (SSE) design ground accelerations by regions of the contiguous U.S. The purpose of this study was to determine the impact of the reference design seismic levels specified by GCRA on the potential HTGR market size.

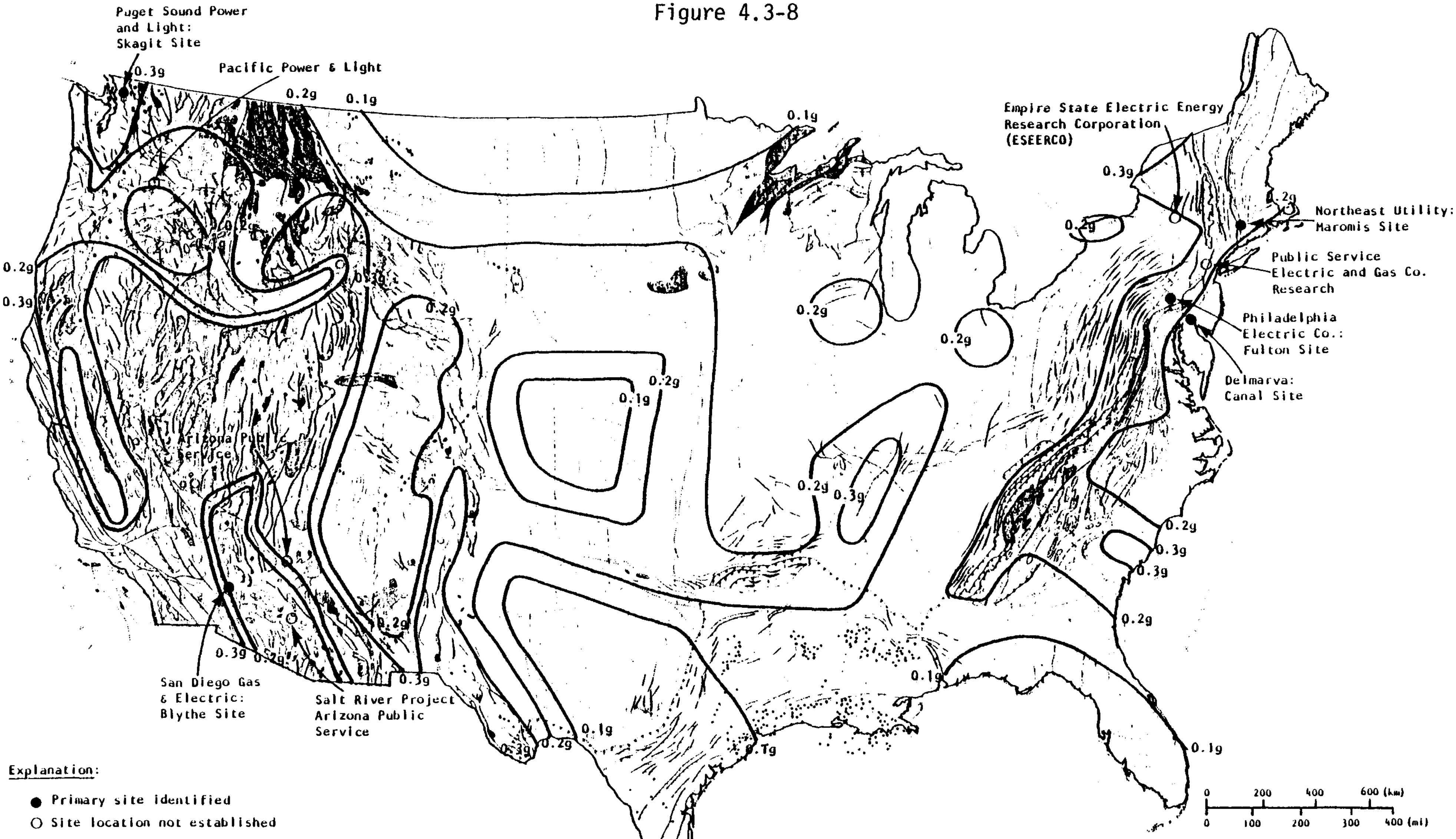
There are two basic steps in specifying the SSE for a site. The first is to determine the maximum earthquake potential of capable faults and seismic sources in the area. The second is to ascertain the dependence of the amplitude of ground motion on earthquake size and distance. The potential earthquake that produces the strongest motion at the site in the critical frequency band can then be identified as the SSE. By utilizing data from existing nuclear plants in the various regions and by analyzing these data with state-of-the-art methodology, the report produced a map, which is shown in Figure 4.3-8, depicting contours of the maximum expected horizontal ground accelerations for nuclear sites. Based on this effort, it appears that the seismic design values for the reference HTGR plants will not unduly restrict the siting capability of any of the HTGR systems.

In addition to the above geological considerations which are applicable to the siting and licensing of any nuclear power plant, applications of the HTGR-R requiring cavern storage have an additional unique requirement; i.e., the proposed site must be located in a region where suitable rock or salt formations exist which can be utilized for cavern storage of synthesis gas and methane. Tank storage of these gases is not economically feasible due to the high pressures and volumes required. The most economical utilization of cavern storage is through the solution mining of salt deposits. Excavation of hard rock sites can also be used, but this process is from six to nine times as expensive as solution salt mining; therefore, salt is the preferred storage medium. Also, the storage medium must have sufficient thickness, low porosity, satisfactory caprock properties, and virtually no faults or fractures which communicate with other strata. Preliminary studies have been performed which indicate large areas of salt formations through the U.S.; however, the suitability of these formations has not been examined. The limiting effect, if any, that this siting requirement will have on the HTGR-R remains to be fully assessed.

4.3.3 Institutional

The purpose of this section is to analyze the HTGR relative to institutional criteria and to determine its siteability relative to the LWR. The quantifiable institutional factors that affect reactor siting can be analyzed by examining the existing siting regulations and criteria. The governing document at present is 10CFR100, which covers factors to be considered when evaluating sites and procedures for determining exclusion areas, low population zones (LPZ), and population center distances around the reactor. The areas and sizes of these zones are determined using 10CFR100 guideline dose limits re-

Figure 4.3-8



Explanation:

● Primary site identified

○ Site location not established

NOTE: The contours shown indicate schematically the approximate level of maximum acceleration that would have to be considered in the siting of nuclear facilities. Contours for accelerations exceeding 0.3g are not shown.

TECTONIC FEATURES

(From Philip B. King, U.S. Geological Survey, 1967)

Albers Equal Area Projection

FIGURE 1 CONTOURS OF MAXIMUM EXPECTED HORIZONTAL GROUND ACCELERATION FOR ROCK SITES

- 2 -

Source: Reference 13

URS/John A. Blume & Associates, Engineers sulting from a Maximum Hypothetical Fission Product Release (MHFPR). The Part 100 dose levels are not acceptable limits for emergency doses to the public under accident conditions but serve only as reference values to be used in evaluating reactor sites. A reactor with an MHFPR which had fewer radiological consequences than the LWR would be allowed to have a smaller exclusion area and low population zone, and thus could be sited closer to the nearest population center according to these criteria.

For the HTGR, the dose rates resulting from the MHFPR are lower than for an LWR at sites with comparable dispersion characteristics and equal exclusion radii. Tables 4.3-9 and 4.3-10 show these doses for the 3000 MWt Fulton steam cycle HTGR. Table 4.3-11 shows these doses for an LWR. The exclusion area radius is 2500 ft for the HTGR and 3400 ft for the LWR, and X/Q is equivalent for both sites. The reference exposures per 10CFR100 are 25 rem whole body or 300 rem thyroid from iodine at the exclusion area boundary for two hours after the start of the release. The reference LPZ dose limits are the same (25 rem and 300 rem) for any individual exposed to the radioactive cloud for the entire period of its passage while located at the LPZ outer boundary. When Tables 4.3-10 and 4.3-11 are compared, it can be seen that the HTGR has an order-of-magnitude advantage over the LWR, even allowing the LWR a 900 ft larger exclusion zone radius. This difference is due to the inherent fission product retention capabilities of the HTGR fuel particles.

Based on the above HTGR performance, an argument can be made that the HTGR is more easily siteable, and, in fact, this difference has been recognized to some degree in Appendix A to Regulatory Guide 4.7, General Site Suitability Criteria for Nuclear Power Stations. This document states that although NRC staff has found that a minimum exclusion distance of 0.4 mile (2100 ft) has been generally used as the LWR standard, in certain instances different dimensions have been established for HTGRs. However, there has not been a definitive set of siting criteria established solely for the HTGR.

At the present time, a major reassessment of nuclear siting criteria is under way. In August 1979, NUREG-0625 was issued (Reference 15). One of its major recommendations is as follows:

> Revise Part 100 to change the way protection is provided for accidents by incorporating a fixed exclusion and protection action distance and population density and distribution criteria.
>
> 1. Specify a fixed minimum exclusion distance based on limiting the individual risk from design basis accidents. Furthermore, the regulations should clarify the required control by the utility over activities taking place in land and water portions of the exclusion area.
>
> 2. Specify a fixed minimum emergency planning distance of 10 miles. The physical characteristics of the emergency planning zone should provide reasonable as-

Table 4.3-9

HTGR

LOW POPULATION ZONE 30 DAY DOSES FOR THE MHFPR

Dose Type	30 Day Dose at the LPZ Boundary (Rem)
Thyroid	150.0
Whole Body	3.2
Bone	1.1
Lung	1.0

Table 4.3-10

HTGR

EXCLUSION ZONE BOUNDARY DOSES FOR THE MHFPR (2500')

Dose Type	0-0.5 hr Dose (Rem)	0.5-1.0 hr Dose (Rem)	1.0-1.5 hr Dose (Rem)	1.5-2.0 hr Dose (Rem)	Total 0-2 hr Dose (Rem)
Thyroid	0.022	0.075	0.347	1.37	1.81
Whole Body	0.002	0.003	0.015	0.042	0.062
Bone	0.009	0.009	0.011	0.017	0.046
Lung	0.002	0.003	0.009	0.031	0.045

Table 4.3-11

Typical Exclusion Zone Boundary Doses for the LWR MHFPR (3400')

Dose Type	Total 2-Hour Dose (Rem)
Thyroid	12.5
Whole Body	.4

Source: Reference 14

surance that evacuation of persons, including transients, would be feasible if needed to mitigate the consequences of accidents.

3. Incorporate specific population density and distribution limits outside the exclusion area that are dependent on the average population of the region.

4. Remove the requirement to calculate radiation doses as a means of establishing minimum exclusion distances and low population zones.

At the time of this writing, a rulemaking process is under way to implement the intent of the above recommendation. The current NRC position in this area was announced in October 1979 when an NRC-EPA task force recommendation was approved requiring two emergency planning zones (EPZ) around each nuclear plant. Within each EPZ, local authorities must be able to take remedial action in case of a radiological threat. Within the inner 10 mile EPZ, the local governments should be able to deal with airborne radiation exposure. Within the outer 50 mile EPZ, plans should be in effect for the impounding of food that may be contaminated. If the recommendations of NUREG-0625 are adopted, the radiological advantages that the HTGR has over the LWR may not be recognized as having merit in the site selection process.

At the present time, General Atomic is developing information to be submitted to the NRC as input to the rulemaking process in order to obtain recognition of the HTGR's inherent design differences.

There will also be unique institutional siting issues associated with siting the HTGR-R. Because of the explosive nature of the stored and transmitted synthesis gas and methane, as well as the toxicity of the carbon monoxide produced, additional institutional siting constraints will probably be imposed. The extent of these constraints is not yet known, but most probably they will take the form of requirements for more distant siting from population areas. While this additional distance is not of technical concern as the synthesis gas can be transmitted over 100 miles, the encroachment of population on suitable, remote sites may act to limit the number of sites which will actually be available for siting the HTGR-R.

4.4 OPERATION AND MAINTENANCE

Although the charges arising from operation and maintenance are a relatively small part of the total cost of power from a nuclear plant, the length of the outages caused by poor operability and maintainability can be the source of major financial losses due to large replacement power costs. For this reason, utilities constantly strive to minimize plant down time by the institution of design and procedural measures. This section of the document will examine the unique aspects of the HTGR that are pertinent to its perceived ability to provide reliable power with high availability, thus minimizing replacement power costs.

4.4.1 Operation

HTGR-SC

One basis for projecting the operability of future HTGR steam cycle plants is by examining the operational record of the prototype Fort St. Vrain reactor. Several studies have done this in the past, one of the more detailed being included in Section 6 of the RAMCO Commercialization Study (Reference 16). This study chronicled the plant performance from September 1970 through September 1977. A review of the data indicates that the vast majority of the problems encountered have not been heat source-related, such as cable separation, feedwater chemistry and fire protection. While these types of problems are plant specific, two generic problem areas have been identified which are having a direct effect on plant availability, namely helium impurity and core power oscillations.

Helium Impurity - The HTGR primary coolant is pure helium. In order to limit impurities such as oxygen and moisture in the coolant, helium purification systems are provided; however, these systems at Fort St. Vrain were not designed to remove the quantities of moisture and oxygen that have been introduced into the PCRV. Oxygen and moisture have a tendency to be absorbed by the graphite in the core and cannot be off-gassed until the core temperature is elevated, thus allowing some graphite corrosion to take place. Technical specifications limit the amounts of impurities allowed in the helium; therefore, high impurity levels restrain plant power ascension. This has been one of the major reasons for Fort St. Vrain's slow return to power after outages.

Large water ingresses have been experienced, primarily due to leaks from the helium circulator auxiliaries. The effect of water in the PCRV on the life of the graphite is currently under study to determine graphite oxidation rates and their long-term effects on plant life. Future HTGRs will have motor-driven circulators instead of the steam- and pelton-wheel-driven circulators used at Fort St. Vrain. These new circulators will have water-lubricated bearings but with a redesigned buffer helium system so that they should experience a greatly reduced frequency of leakage. They will also operate at lower speeds, have a new bearing design, and relocate the thrust bearing into the drive motor. Through proper design attention to possible sources of water ingress and to graphite component design margins, the effects of water ingress on plant availability should be minimized.

The effect of moisture on fuel performance is a related problem. The fuel particles at Fort St. Vrain have four layers of coatings surrounding the fuel kernel. These coatings act like a pressure vessel to retain fission products within the particle. At local high temperatures during normal plant operation, some particles may experience failure of the outer coating. When the failed particles come in contact with moisture at elevated temperatures, hydrolysis of the fuel occurs, releasing all of the particle's fission products into the primary coolant. The amount of moisture needed for hydrolysis is extremely small as the moisture from humid air that enters the primary system during fueling operations is sufficient to cause hydrolysis. New multiple layer coatings have been developed which should reduce this problem for future HTGRs; however, cost/ benefit analyses show that it is not cost effective to try to design fuel particles that will experience a near zero failure rate. Fission products that are released over fuel life can generally be tolerated at the levels predicted with the new coatings as discussed in the Maintenance section. It is interesting to note that even though Fort St. Vrain has experienced large water ingresses in its operation to date, primary coolant activity is 30% of that predicted and a factor of 60 below the technical specification limit. This indicates the degree of conservatism that has been incorporated into the fuel design.

Core Power Oscillations - In late 1977, while approaching 60% power, temperature fluctuations were observed in the Fort St. Vrain primary coolant circuit at individual core region outlets and at the steam generator module inlets. An intensive investigation into the nature and causes of the fluctuations was initiated. The nature of the oscillations is such that they have been observed at power levels between 30% and 70% while the temperature swings generally stayed within technical specification limits. The period of the temperature oscillations is irregular, ranging from five to twenty minutes, while the power fluctuations are very rapid and do not show the normal temperature feedback effects.

The most probable explanation of the temperature and neutron flux fluctuations is small movements of internal reactor components with resulting changes in coolant flow through the gaps between the components. This motion is most likely induced by pressure differences in the gaps and thermal gradients in the core components. Through data collection and experimentation, a core pressure drop vs. core flow rate threshold has been defined. Based on this threshold, operation of Fort St. Vrain has been limited to 70% power.

Region constraint devices were added in late 1979 that are intended to limit fuel block movement by tying the top block in each column to the adjacent blocks. The test program to verify the adequacy of this modification will not begin until Fall 1980. It is expected that this program will confirm the causes of the oscillations and will result in the release to operate Fort St. Vrain at 100% rated power.

The one additional restraint to sustained full power operation of Fort St. Vrain is the warranty on the existing fuel. The warranty for fuel segments 2 through 9 is limited to reactor operation up to 590 MWt until December 31, 1984, which corresponds to a reactor power level of 70%. A special allowance of no more than 500 hours per cycle at higher power levels is allowed by the fuel manufacturer, General Atomic Company. This limited performance warranty is the result of the complex litigation that took place between GAC and the Fort St.

Vrain owner and is not based on a technical limitation of the fuel, only a contractual one. The fuel manufacturing technology that is in place will allow full fuel performance warranties; therefore, it is not expected that future plant performance will be limited by this type of problem.

One of the outstanding operational characteristics of the HTGR that has been confirmed by Fort St. Vrain experience is its ability to withstand severe transient conditions without adverse effects. The Fort St. Vrain reactor has been subjected to complete loss of forced circulation several times during its life, the longest duration being approximately 15 minutes, without any damage or increased primary circuit activity. This "forgiving" characteristic of the plant is perhaps the single most important operational feature of the HTGR and provides an effective line of defense against human error which otherwise may have significant consequences with regard to plant protection.

HTGR-GT

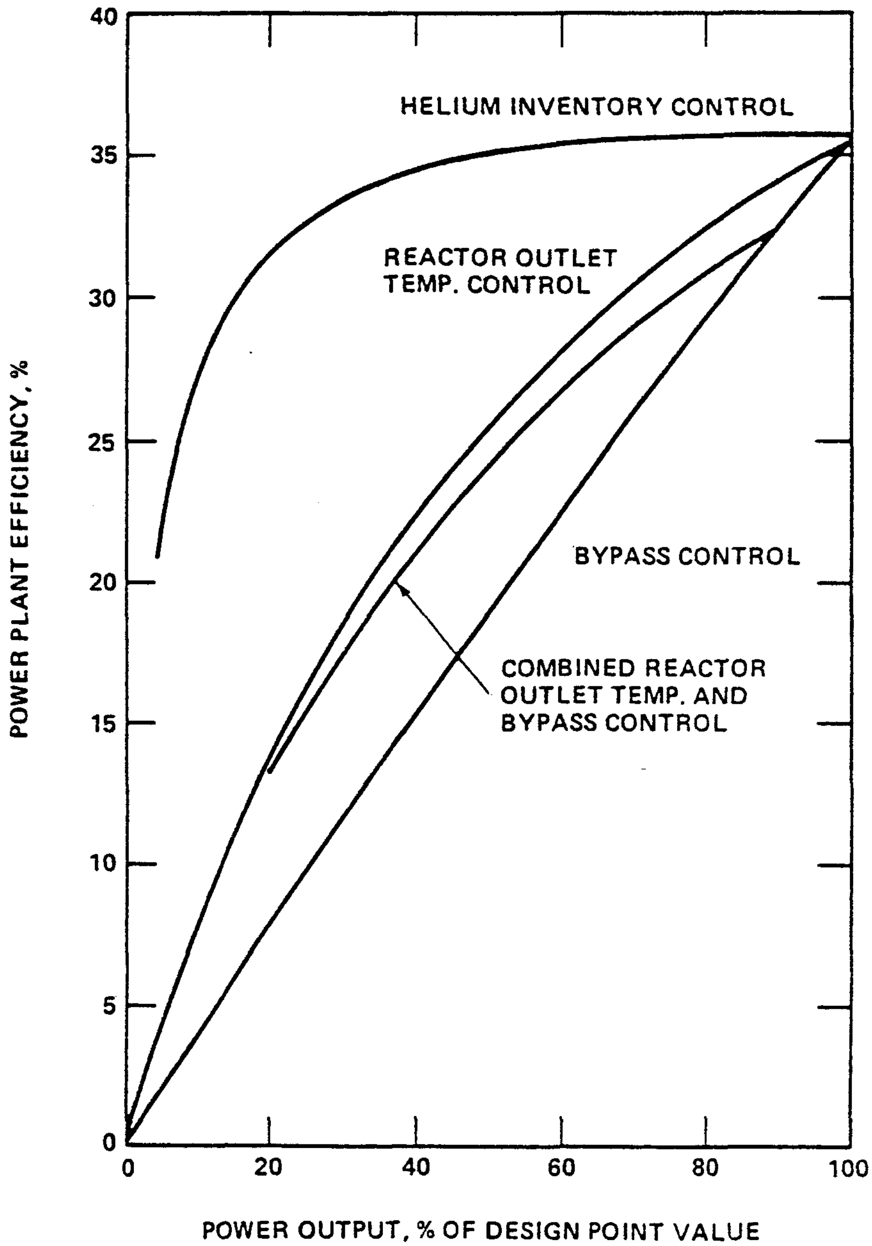
Because the HTGR-GT is a direct, closed Brayton cycle plant, its operation will be unique relative to other types of large generating stations. As a result, extensive operator training will be required to operate and maintain the plant. To better understand the following discussion, a detailed description of the reference design is given in Section 6.1.

Three control concepts have been considered for the HTGR-GT, namely:

- Bypass flow from the high pressure to the low pressure sections of the power conversion loop
- Turbine inlet temperature variation
- Helium inventory variation

The bypass flow control is the only concept with sufficiently rapid response to limit turbomachine overspeed following a 100% load rejection. This concept has, however, the disadvantage of low efficiency at partial load as shown in Figure 4.4-1. For this reason, it is desirable to combine bypass flow control with turbine inlet temperature control and helium inventory control. This combination is currently the reference control concept and allows 10% step load pickup with a two-hour steady-state period between steps. The addition of helium inventory control is considered to be an added cost, the economics of which depend on whether or not the plant would be utilized in a load following mode. It can be seen from Figure 4.4-1 that inventory control does have a significant effect on plant performance for partial load operations. However, rapid load pickup does not appear feasible on economic grounds with inventory control due to the amount of helium which must be injected into the PCRV and the rate at which this injection must take place. For these reasons, a utility which may wish to operate the HTGR-GT in a load-following mode must

Figure 4.4-1



GT-HTGR PART-LOAD EFFICIENCY
FOR THE VARIOUS CONTROL MODES

Note: Full power efficiency for the current HTGR-GT reference design is 39.6%.

Source: Reference 9

be cognizant of its performance limitations at partial load and analyze the cost effectiveness of the helium inventory system for its specific needs.

In order to start up the HTGR-GT, the turbomachines must be powered by an external source to attain a rotational speed at which the compressor develops a sufficient pressure ratio to allow the turbine to produce the power needed to drive and accelerate the compressor. This occurs at one-third to one-half synchronous speed and requires approximately 5000 HP per machine. This power will be supplied by motoring the generator with a 5 MW static frequency inverter for each machine. During startup, helium inventory is reduced to 40-50 percent of full load inventory in order to minimize power requirements. The turbomachine will operate in this motoring mode for several hours to allow for thermal conditioning of the system.

Although a detailed analysis has not yet been completed, it is expected that the HTGR-GT will not be able to operate with only one turbomachine in operation. With one loop in operation, a reverse flow condition is established through the second loop which would affect the gas flow paths internal to the PCRV. This reverse flow phenomenon is unique and its effects on plant performance, core internal components and the turbomachinery have not been fully analyzed and its licensing implications not yet determined. Also, once one loop is shut down, the power required to restart that loop with the other loop up and running is expected to be much higher than that required during normal startup, thereby requiring additional starting capacity.

In summary, the HTGR-GT has unique operational characteristics which have been identified but not yet fully analyzed due to the preliminary nature of the reference design. As work continues on this concept, a better understanding of its complexities will be gained.

HTGR-R

The technical description of the HTGR-R is contained in Section 7.1. The current reference design is an indirect cycle which utilizes a secondary helium loop to isolate the reformer from the primary helium coolant. The steam generators are also located in the secondary loop. Only preliminary conceptual work has been done on this system; therefore, its operational aspects have not been examined in detail. The two major areas of potential operational problems are (1) the control of the secondary helium loop and the feedback of its operation to the primary loop and (2) the control of the reformer feedstocks and effluents. A critical consideration will be the control of the heat transfer and the pressure differential across the intermediate heat exchangers (IHX). The IHX will only be able to withstand a limited number of maximum differential pressure transients due to material limitations; therefore, proper control of the primary and secondary loop pressures is necessary. As for the reformer loop operation, it is expected that the control of the reformer feedstocks--methane and steam--will require feedback into the secondary helium loop, thereby creating a rather complicated operational system with the reactor primary coolant flow, secondary coolant flow and reformer feedstock and effluent flow all interdependent. The presence of hydrogen in large quantities from the reformer also adds significant safety implications to the design of the control system. A great deal of work remains to be done in this area for the HTGR-R before its operational characteristics can be quantified.

4.4.2 Maintenance

HTGR-SC

As in the previous section, the generic maintenance aspects of the HTGR will be examined by reviewing the experiences of HTGR steam cycle plants.

The steam cycle HTGR system has many of the same components and numbers of components as conventional fossil and LWR generating plants. Therefore, a significant difference in maintenance arising from component design is not anticipated. However, the dose rates and associated radiation exposures due to maintenance activities for the HTGRs are expected to be less than those experienced in LWRs. Experience in operating the early HTGRs supports this expectation, which is the result of the primary circuit activity being relatively low when compared to LWRs.

The Peach Bottom 1 HTGR, operated by Philadelphia Electric Company, generated a total of 1200 GWe hours of net power from March 1966 to October 1974. Yearly and cumulative exposure data are listed in Table 4.4-2, which was taken from Reference 17. Because Peach Bottom was a 40 MWe prototype reactor, it can be compared with early, low power LWRs. Exposure data for Big Rock, Humbolt and Lacrosse are presented in Figure 4.4-3, where they are compared against the Peach Bottom data. The man-rem exposure rate at Peach Bottom can be seen to be appreciably less than the LWRs.

At the time of its first refueling in February 1979, Fort St. Vrain had generated 953 GWe hours of net power. Personnel exposure data collected indicate that Fort St. Vrain has exposure characteristics similar to those shown by Peach Bottom 1. Table 4.4-4 shows the Fort St. Vrain man-rem exposure data for the years 1977 and 1978, which are then compared to similarly sized plants in Figure 4.4-5. Although it is still relatively early in its life, it can be seen that Fort St. Vrain exposures are below all LWR exposures with the exception of the San Onofre PWR, which had relatively equivalent exposures. It is interesting to note that during the Fort St. Vrain refueling outage, exposure to personnel amounted to 0.27 man-rem. Of this total, 0.013 man-rem was due to replacement of one of the main helium circulators, 0.037 man-rem was due to work performed in the Hot Service Facility, and the remaining 0.22 man-rem was due to handling spent fuel elements and control rod drive units (Reference 18).

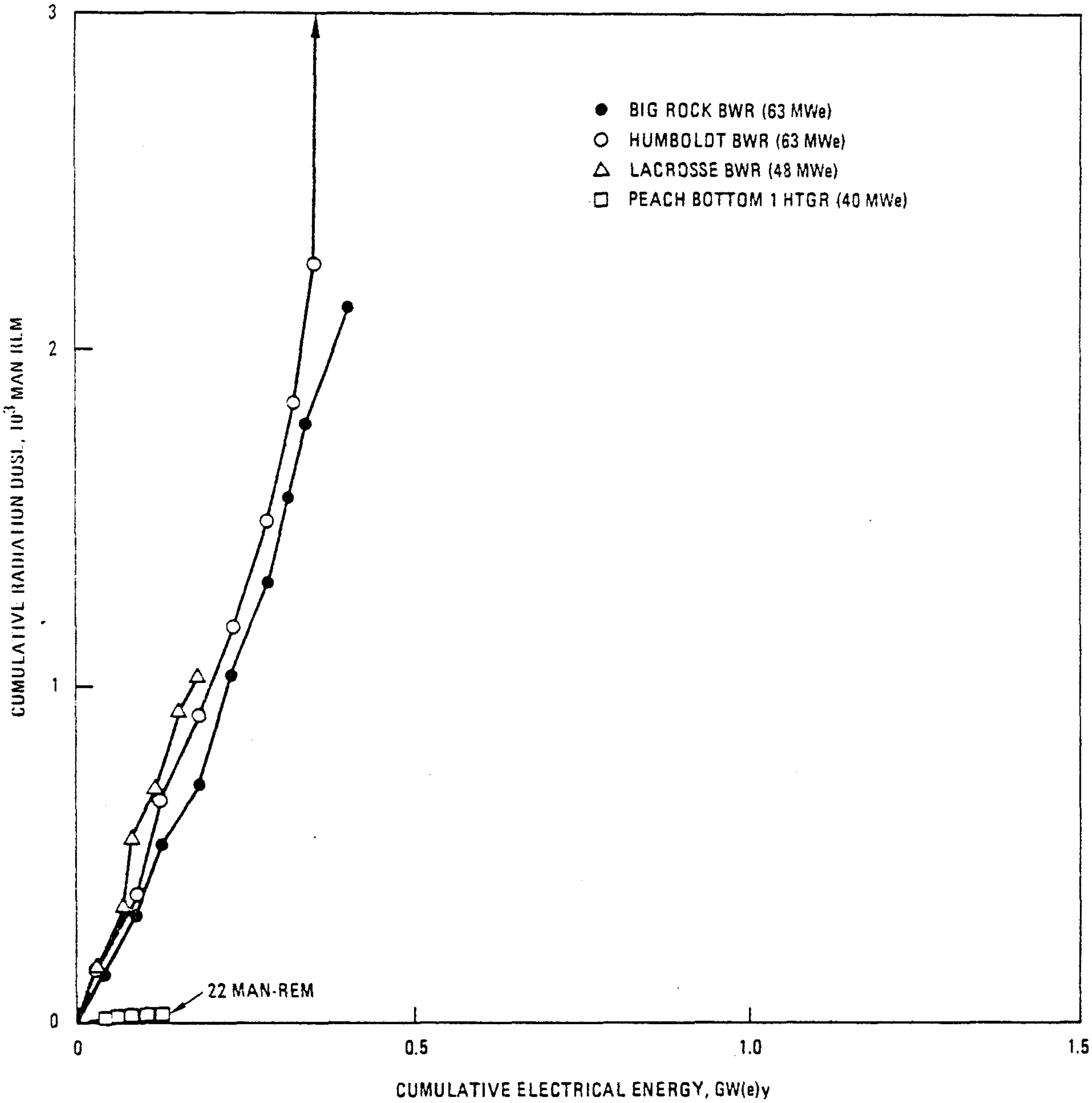
Table 4.4-2

PEACH BOTTOM HTGR OPERATING EXPERIENCE

Year of Operation	Man-Rem Exposure		Net Power Generation [GW(e)y]		Cumulative Occupational Exposure [man-rem/GW(e)y]
	By Year	Cumulative	By Year	Cumulative	
1967	∿3	∿3	0.017	0.017	176
1968	∿3	∿6	0.015	0.032	188
1969	∿3	∿9	0.0157	0.048	188
1970	∿3	∿12	0.0163	0.068	176
1971	∿4	∿16	0.024	0.088	182
1972	∿3	∿19	0.012	0.102	186
1973	∿3	22	0.021	0.1205	183
1974	NA	NA	0.0183	0.140	NA

Source: Reference 17

Figure 4.4-3



Cumulative occupational exposures for early, low-power nuclear plants

Source: Reference 17

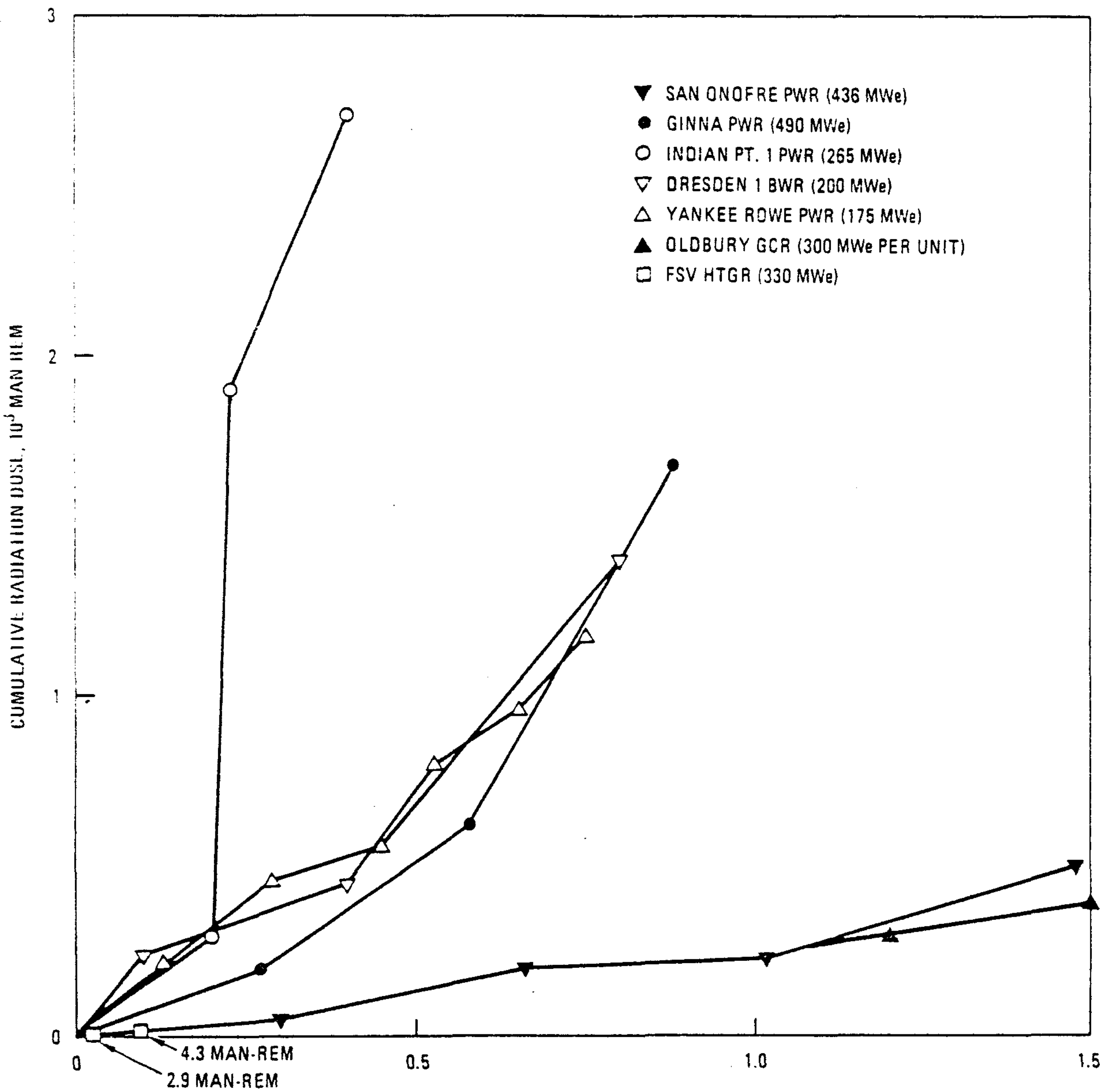
Table 4.4-4

FSV MAN-REM EXPERIENCE

Personnel	Exposure	Averaged Man-Rem	Net Power Generation [GW(e)y]	Rate of Accumulation [man-rem/GW(e)y]
1977				
946	None	0		
55	<100 mrem	2.75		
1	100-250 mrem	0.175		
		2.9	0.0256	113
1978				
896	None	0		
34	<100 mrem	1.7		
0	100-250 mrem	0		
		1.7	0.0695	24
Cumulative		4.6	0.0951	48

Source: Reference 17

Figure 4.4-5



Cumulative occupational exposures for medium-power nuclear plants

Source: Reference 17

For the reference 900 MWe HTGR-SC plant, the refueling operation is expected to result in 5.5 man-rem of exposure, which is consistent with the Fort St. Vrain data when it is extrapolated for reactor size and the time delay that occurred at Fort St. Vrain between shutdown and the start of refueling operations. This compares to an average actual LWR refueling exposure of 39 man-rem in 1976 according to NUREG 0323. Table 4.4-6 shows the expected and the design basis exposures for the reference steam cycle HTGR. These data are then compared to LWR experience in Figure 4.4-7. It can be concluded that total HTGR exposure rates should be significantly lower than those of the LWR.

It should be noted that the actual HTGR exposure rates, while they have been at or below predicted values to date, are dependent on fuel design. The Peach Bottom and Fort St. Vrain reactors both utilize highly enriched uranium (HEU-93%) fuel. The reference HTGR fuel is currently LEU-20% enriched uranium, which will result in differences in the generated fission products. For example, Ag-110 m, which is not a major product in HEU fuels, is produced from the more abundant PU-239 in the LEU fuels. With a half life of approximately 250 days, it could prove to be a significant factor to be considered in future HTGR maintenance work and is currently being investigated along with improved particle coatings to retain higher percentages of the fission products.

The economic value of the reduced exposures of the HTGR is difficult to quantify at this time. GCRA performed a survey of its member nuclear utilities in an attempt to determine the worth of this feature to the utility industry. In response to one of the questions, several utilities felt that lower personnel exposure levels would be an advantage for the HTGR as long as it could achieve a 20% to 75% decrease from the current LWR levels of about 500 man-rem/plant year. Other utilities felt that the lower exposures would not prove to be a significant advantage for the HTGR for two reasons: (1) the claims of the lower exposure levels cannot be given much credibility until they are proven in a commercial size plant having significant operating history and (2) LWR exposures will probably decrease in plants built after the year 2000, thereby decreasing the relatively large perceived HTGR advantage. In trying to quantify the value of a man-rem of exposure, it was quite evident that this number is very site specific. Values ranged from $600 to $20,000, with the weighted average around $1.5K per man-rem, which is close to the 10CFR50, Appendix I guideline of $1K. It was also noted that for specialty skilled workers, a man-rem can be as high as $15K to $20K. The consensus of opinion of the survey was that it is important for the HTGR to retain its potential for lower personnel exposure and that the best means of accomplishing this would be through fuel performance.

A major maintenance activity for any nuclear plant is refueling. For the HTGR, refueling activities and equipment have received a great deal of attention and analysis. A new rapid refueling scheme has recently been developed and is being incorporated into the reference HTGR designs. It is expected that with properly

Table 4.4-6

MAN-REM PREDICTIONS FOR HTGR-SC

Type of Operation	Annual Man-Rem Exposure for 900 MW(e) Unit: Expected	Annual Man-Rem Exposure for 900 MW(e) Unit: Design Basis
Refueling	5.5	20
Reactor Operation and Surveillance	7.0*	20
NSS Maintenance and ISI	10.1	20
BOP Maintenance	25.0**	50
Special Maintenance	3.2***	20
	50.8	130
Rate of Accumulation		
[900 MW(e), 80% load factor]	$\frac{50.8}{0.9 \times 0.8} = 70 \frac{\text{man-rem}}{\text{GW(e) y}}$	$\frac{130}{0.9 \times 0.8} = 180 \frac{\text{man-rem}}{\text{GW(e)y}}$

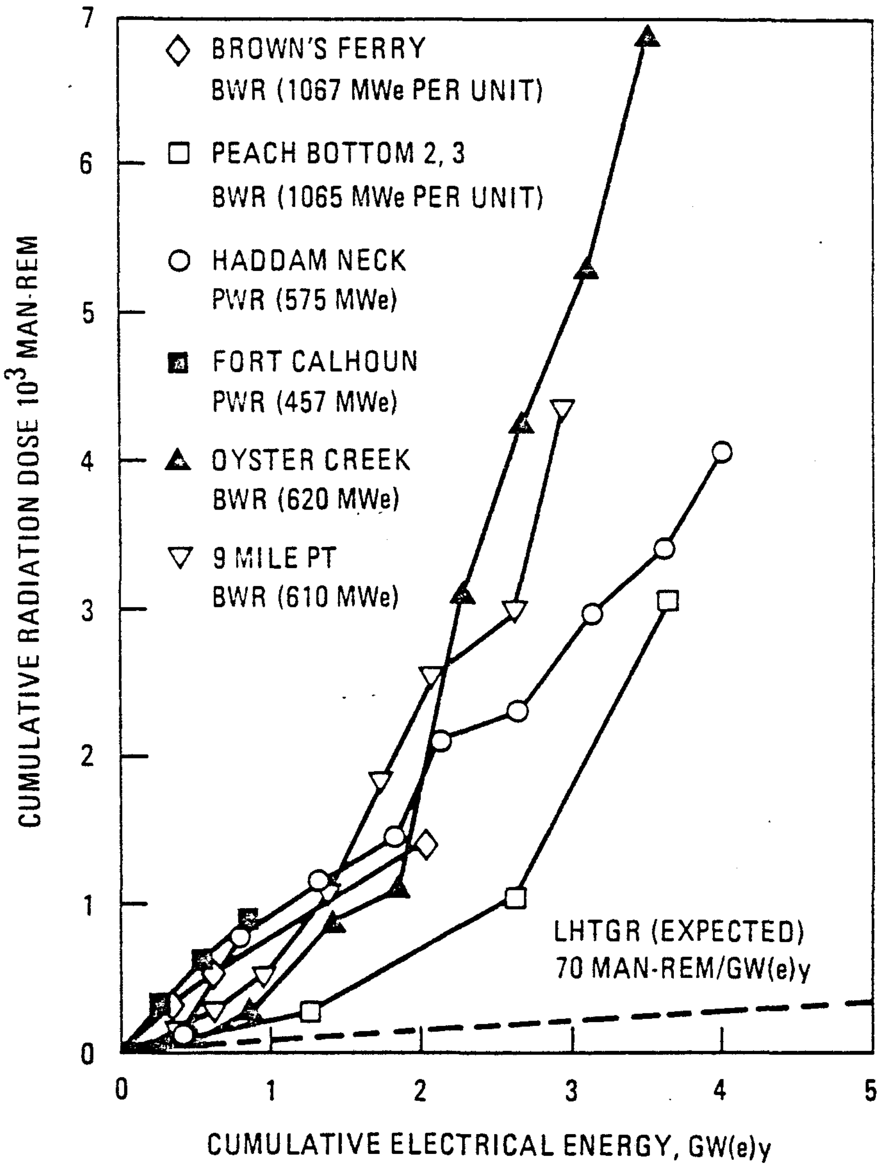
*From low-level noble gas activity in containment building.

**Assumed; no information is available from an architect-engineer.

***Tube plugging every year @ 1.0 man-rem; steam-generator removal every 10 years @ 1.65 man-rem; circulator removal every 2 years @ 1.0 man-rem.

Source: Reference 17

Figure 4.4-7



Cumulative occupational exposure for large nuclear plants (Part 2)

Source: Reference 17

operating equipment, the refueling activities for the reference 2240 MWt HTGR can take place in 7 days. This compares favorably with current LWR experience of approximately 35 days for refueling, exclusive of other activities. A complete description of HTGR refueling activities is contained in Reference 18.

HTGR-GT

Maintenance of the gas turbine HTGR has been the subject of an extensive study by General Atomic Company. The critical path item for maintenance activities is the removal and installation of a turbomachine. With the present design, a period of 21 days is required for removal and installation of a spare machine. It is expected that each plant will have one spare turbomachine which will be available for immediate replacement. After a machine is removed, it is placed in a shielded cask and transported to a maintenance facility where it will be decontaminated to allow hands-on maintenance. It has not been determined as of yet how the turbomachine will be decontaminated and what effect this decontamination will have on machine life. These are major open issues for the HTGR-GT and are currently under study. Preliminary assumptions predict that the exposure for turbomachine removal will be 2.1 man-rem (Reference 19); however, no predictions have been made regarding subsequent decontamination and disassembly.

HTGR-R

Because of its early conceptual design, little work has been done to define the maintenance aspects of the HTGR-R. However, several major unique activities have been identified. The intermediate heat exchangers which are currently being considered are fabricated from Inconel 617. As a result, they are expected to have a design life of only 20-25 years, thus requiring changeout at least once during plant life. There are eight IHXs in the reference design, each weighing approximately 300-400 tons. Also requiring periodic changeout will be the catalyst in the reformers with a frequency of once every 8-10 years. With helium circulators located in both the primary and secondary helium loops, the total amount of major equipment requiring regular maintenance is greater for the HTGR-R than any other HTGR system. Future studies will need to address these maintenance aspects of the HTGR-R.

4.5 FUEL CYCLE

4.5.1 Introduction

Two basic fuel cycles have generally been considered for thermal-spectrum reactors, the Low-Enrichment Uranium (LEU) cycle and the High-Enrichment Uranium (HEU) cycle. While the LEU cycle has traditionally appeared more attractive for LWR plants, the HEU cycle generally looks advantageous for the HTGR. A number of variants on each of these cycles is possible depending upon whether fuel recycle is utilized and upon the makeup fuel to be used with recycle. The various fuel cycles and reactor systems were the subject of study by the Department of Energy (DOE) through the Non-Proliferation Alternative Systems Assessment Program (NASAP).

It is becoming increasingly apparent that the selection of a national fuel cycle strategy is, and will continue to be, surrounded by confusion and uncertainty. Probably most apparent is the current uncertainty in policy directions as a result of nuclear weapons proliferation concerns. The economics of fuel recycle must also be regarded as an uncertainty until commercial experience is available with spent-fuel reprocessing, bred-fuel refabrication, nuclear waste processing and waste storage. The commercialization process itself poses a serious uncertainty on recycle implementation, largely due to the uncertainties in acceptable technology directions and the economic incentives for those directions. As a result of these uncertainties, the interest of utilities might be best served by the support of reactor and fuel cycle technologies having sufficient flexibility to accommodate any of the possible directions that might evolve. Not only should a reactor have sufficient fuel cycle flexibility to accommodate any of the several possible preferred directions, but it also should allow an evolution to more advanced technologies as policy definition, technology development and commercialization favor the appropriate evolutionary steps. With the HTGR, it is feasible to deploy an HTGR industry on the basis of a once-through fuel cycle strategy and subsequently adopt a recycle fuel management plan if and when it becomes desirable with no significant change to the reactor. This flexibility of the HTGR would assure that a utility could progress along an evolutionary fuel cycle path with no inconvenience to the potential user.

4.5.2 Resource Utilization

The HTGR offers considerable potential for improvements in U_3O_8 utilization efficiency over the LWR, independent of which policy direction might be pursued by this or future administrations. Both plant thermal efficiency and reactor conversion ratios are important factors in the U_3O_8 utilization. Table 4.5-1 summarizes U_3O_8 requirements for several fuel cycle alternatives, for both LWR and HTGR plants. The table shows inventory requirements as well as annual makeup requirements. The load factor chosen here is slightly higher than the 65% generally assumed in previous national cost-benefit studies, but somewhat lower than the 75% now being used in NASAP studies. An enrichment tails assay of 0.1% has been selected (rather than 0.2% now used by the DOE), since a lower assay is expected after the turn of the century as a result of improved enrichment technologies.

Present data indicate that the 20% LEU/Th once-through cycle allows a 30-year U_3O_8 commitment for the HTGR which is only 75% of the standard LWR once-through, i.e., a U_3O_8 commitment improvement of 34% over the LWR. The improvement is still about 20% relative to the LWR with an extended fuel burnup lifetime.

Table 4.5-1

U_3O_8 REQUIREMENTS AND Pu_f DISCHARGE
FOR ALTERNATIVE FUEL CYCLES IN LWR AND HTGR PLANTS*
(LOAD FACTOR = 70%; ENRICHMENT TAILS = 0.1%)

REACTOR	FUEL CYCLE	INVENTORY, ST U_3O_8/GWe	ANNUAL MAKEUP ST U_3O_8/GWe-yr	30-YR TOTAL ST U_3O_8/GWe	Pu PRODUCTION kg/GWe-yr
LWR	3.2% LEU; O.T. (Once-Through)	566.	155.	5061	152.
LWR	4.4% LEU; O.T.	734.	131.	4533	110.
LWR	3.2% LEU; U RECYC	559.	120.	4039	152.
LWR	20% LEU/TH; RECYC	655.	93.	3352	57.
LWR	20% LEU/TH; RECYC	590.	77.	2823	6.
HTGR	20% LEU/TH; O.T.	435.	114.	3741	31.
HTGR	20% LEU/TH; RECYC	400.	79.	2691	31.
HTGR	93% HEU/TH; RECYC	500.	43.	1747	3.
HTGR	93% HEU/TH; RECYC (Heavy Load)	750.	29.	1591	3.

*LWR thermal efficiency assumed at 33.4%;
HTGR thermal efficiency assumed at 39.6%.

4.5.3 Fuel Cycle Economics

On the basis of most recent nuclear growth projections, it is unlikely that the cumulative U_3O_8 requirements will present a significant problem in the next 50 years, but large annual uranium requirements could have an impact on U_3O_8 prices and, therefore, on reactor economics. There are two factors that are particularly important relative to fuel cycle economics:

1. Fuel costs, i.e., the costs associated with fuel consumption and fuel inventory working capital

2. Handling costs, i.e., the costs associated with fabrication, shipping, reprocessing, refabrication, etc.

The first of these factors is generally recognized as being important, though its importance frequently tends to be overstated. The second factor is not so generally appreciated, perhaps due to unfamiliarity with recycle operations.

Fuel Costs - At the outset, it is important to note that fuel costs, and particularly those associated with U_3O_8 costs, are not as significant relative to generating costs as are fuel costs in fossil-fueled plants. Specifically, while coal resource and freight costs typically contribute 50% to the cost of generation in coal-fired plants, U_3O_8 supply costs contribute only 5% to 15%, depending on the particular fuel cycle. The more important question, then, is the effect of possible increases in U_3O_8 prices on energy generating costs.

The cost penalty of increased U_3O_8 prices on generating costs is influenced by two factors:

- The cost increase of the enriched uranium (per unit of U-235 contained) resulting from U_3O_8 price increases

- The cost increase of energy generation resulting from the fuel cost (U-235) increase

The first factor arises simply because the U-235 cost depends both on the U_3O_8 price and the separative work price; the U_3O_8 price contributes typically about one-half of the U-235 cost. The second factor reflects the fact that resource-efficient reactors use less fuel; therefore, fuel cost increases contribute less to generating costs in the more efficient reactors.

Some of the nuclear fuel cost penalty arising from potential U_3O_8 price increases in the next few decades might also be largely offset by separative work price decreases as Advanced Isotope Separation Technology is introduced. The basic conclusion, then, is that the potential effect of large U_3O_8 price escalations can be minimized by resource-efficient reactors. In addition, the introduction of resource-efficient reactors can help to stabilize the price of

U_3O_8 through the lowering of U_3O_8 demands. The HTGR is well suited for the role of this resource-efficient reactor as shown by Table 4.5-1.

Fuel Handling Costs - Typically, the fuel-handling cost for the LWR once-through fuel cycle contributes about 15% to the total fuel cycle cost; the fuel cost contributes the other 85%. With recycle, the handling cost fraction increases to approximately 30% to 40%, both because the costs of reprocessing and refabrication are significant and because the fuel cost component is reduced by the more efficient uranium utilization. For the HTGR, fuel handling costs for the once-through fuel cycle contribute about 25% to the total fuel cycle costs while with uranium recycle, handling costs are approximately 50% of total fuel cycle costs. The handling cost component tends to be different for different fuel cycles because of differences in handling difficulties (mostly refabrication) and because of the fraction of recycled fuel that is involved.

Total Fuel Cycle Costs - Table 4.5-2 presents the relative total fuel cycle costs for the HTGR and the LWR for various fuel cycle scenarios. These costs are based on recent comprehensive studies performed by General Atomic Company using the economic assumptions presented in Table 4.5-3. They represent the calculated fuel cost differentials measured in mills/kwhr.

Based on the data presented in Table 4.5-2, it can be seen that for the once-through fuel cycle for the steam cycle HTGR, the fuel cycle costs are basically the same as for present LWRs and their once-through fuel cycle. The steam cycle fuel cost advantage would be maximized if it were to utilize HEU fuel with full recycle. For the HTGR-GT and HTGR-R, these reactors will have a fuel cycle cost disadvantage relative to the LWR unless HEU and full recycle are allowed. This is basically due to the more conservative fuel design that is required at the higher coolant temperatures (850°C core outlet) of these reactors.

4.5.4 Advanced Converter Reactors and Symbiotic Systems

Both the LWR and the HTGR have potential for reactor and fuel cycle improvements. These two systems plus the light water breeder reactor (LWBR) are the candidates with the greatest potential as advanced converter reactor (ACR) concepts; however, the HTGR appears to offer the best possibility for an economically attractive, resource-efficient reactor.

Although traditional thinking some five to ten years ago envisioned the complete replacement of thermal-spectrum reactors by fast breeder reactors (FBR) in the long-range future, it is now becoming apparent that the optimum nuclear system will consist of a symbiotic combination of ACRs and FBRs. Several factors contributing to this realization are:

- The nuclear growth projections now indicate that severe resource constraints will not be imposed on the mining and

Table 4.5-2

Relative Fuel Cycle Costs for Alternative Fuel Cycles

Reactor	Fuel Cycle	Relative Fuel Cycle Cost
LWR	LEU; O.T.	1.00
LWR	U+Pu Recycle	0.80
LWR	U Credit	0.91
HTGR-SC	LEU/Th(20%); O.T.	0.99
HTGR-SC	HEU/Th(93%); U Recycle	0.73
HTGR-GT	LEU/Th(20%); O.T.	1.10
HTGR-GT	HEU/Th(93%); U Recycle	0.78
HTGR-R	LEU/Th(20%); O.T.	1.11
HTGR-R	HEU/Th(93%); U Recycle	0.81

Table 4.5-3

Fuel Cycle Cost Economic Assumptions

Capacity Factor	70%
Tails Assay	0.2%
Startup Date	6/95
Plant Efficiency	39.5% HTGR and 33.0% LWR
Inflation Rate	6%
Working Capital Rate*	15.6%
Discount Rate*	10.2%
Levelizing Period	30 yrs.
Fuel Costs	
Conversion ($/kg)	5.0
Enrichment ($/kg-SWU)	100.0
U_3O_8 ($/lb)	Reference - 1980 - 45.0
	2010 - 75.0
	2020 and onward - 120.0
	Low - Constant 40.0
U233/U235 Parity Ratio	1.15
Pu/U235 Parity Ratio	0.60
Fuel Handling Costs	As per Reference 24

*The discount rate is the weighted cost of capital. The working capital rate is the interest rate on monies used to purchase fuel and fuel handling services and includes the weighted cost of capital and the federal tax on the equity capital.

milling industry for some 30 to 50 years, particularly if more resource-efficient reactors and fuel cycles are introduced.

- The cost penalty associated with increased U_3O_8 prices will not be substantial if resource-efficient reactors and fuel cycles are introduced.

- The capital cost and operating cost of the liquid metal fast breeder reactor (LMFBR) now appear to be such that very high U_3O_8 prices would be required to justify the LMFBR (without improvements or modified fuel cycles).

- Licensing of the LMFBR will probably be more difficult, at least in the early years.

- The concerns of plutonium diversion will probably require that FBR plants be located in secure reservations, possibly under government control.

A strategy creating a symbiotic relationship with the coupling of four HTGRs to one fast breeder reactor is one with much potential and many long-range benefits. In order to implement such a strategy, it would be necessary to create the marketplace for U-233 utilization prior to FBR deployment rather than subsequent to it.

4.5.5 HTGR Flexibility

Three basic fuel cycles were examined in the NASAP studies for thermal spectrum reactors:

LEU (with $\sim$10% uranium enrichment) Cycle

LEU/Th (with $\sim$20% uranium enrichment) Cycle

HEU/Th (with $\sim$93% uranium enrichment) Cycle

An LEU/Th cycle with 20% uranium enrichment has received considerable attention, particularly in the NASAP studies because:

1. The enrichment of the initial feed material is below that of weapons-grade U-235.

2. The plutonium bred into the cycle is largely consumed so that the discharge plutonium content is substantially reduced over that of the lower enrichment LEU cycles.

3. The U-233 is (or can be) "denatured" with U-238.

While the primary NASAP attention for near-term utilization has centered on the once-through fuel cycle using LEU or LEU/Th fuel, it is expected that greater economic pressure for recycle will develop as the price of U_3O_8 increases. The NASAP studies indicate that one desirable possibility for subsequent recycle in thermal-spectrum reactors would involve the use of the HEU/Th cycle with the recycle of either denatured U-233 or gamma-active U-233. It is expected that plutonium will ultimately be utilized in secure FBR plants with either denatured U-233, or gamma-spiked U-233 or Pu, fed to LWR and ACR plants.

Based on the current political uncertainties associated with closing the fuel cycle, it could be argued that a reactor should have sufficient fuel cycle flexibility to accommodate any of the several possible preferred directions. For the HTGR, it is quite practical to deploy an industry on the basis of a once-through fuel cycle strategy and subsequently adopt a recycle fuel management plan if and when it becomes desirable with no significant change to the reactor.

In the near term, it is expected that the LEU/Th once-through fuel cycle with fuel storage would represent the optimum direction for the HTGR in terms of national policies, although the economic incentives for utilizing this cycle are meager for the HTGR-SC and become disincentives for the HTGR-GT and HTGR-R. At some appropriate future date, the U-233 stored in the spent fuel could be separated and recycled in the same reactor. Finally, when U-233 becomes available from an external source such as an FBR, the same HTGR plant could then utilize the U-233 as a makeup fuel and the plant would perform as a near-breeder reactor, i.e., with a conversion ratio of approximately 0.9.

4.5.6 Summary

Future directions for nuclear fuel cycles are being complicated by uncertainties arising from national policies, economic factors and industry commercialization problems. While long-range development should favor the recycle of fuel in resource-efficient reactors, it is desirable for utilities to have access to reactors that operate economically on a once-through fuel cycle in the near term but that can accommodate the more efficient fuel cycles as policies and facilities allow these improvements. The HTGR has the flexibility to adapt to these changing conditions with no redesign of the reactor itself. Furthermore, the efficiencies of the alternative cycles for the HTGR are such that improved resource utilization will occur.

When compared to LWR fuel costs, the economics of the HTGR fuel cycles lead to the following conclusions:

- The HTGR fuel cycle cost advantage is appreciable only when HEU fuels are utilized. It is important that this option be maintained as the HTGR fuel cycle goal.

- The standard 33,000 MWD/T LWR once-through and the LEU/Th HTGR steam cycle once-through fuel costs are the same. Extending the LWR burnup to 50,650 MWD/T leads to a 7% reduction in the LWR once-through costs.

- For a recycle LEU/Th cycle, the HTGR and LWR costs are within 2%. The previously calculated HTGR advantage of 8%-10% has diminished due to the $23,800/block refab cost, which is twice the HEU refab cost due to much lower recycle block throughputs for the LEU/Th cycle.

Future work which may affect the above conclusions must be performed to resolve the uncertainties that exist regarding HTGR waste treatment, particularly for C-14, and HTGR fuel block shipping and packaging costs. One of the primary incentives for the HTGR, namely the flexibility of its fuel cycle, is dependent on the political process to bring its potential incentives to fruition. If the government will allow pursuit of the thorium fuel cycle, then the fuel cycle-related economic incentives of the HTGR can be realized.

4.6 ADVANCED APPLICATIONS

The evolutionary potential of the HTGR offers the utility industry the opportunity for future expansion into new energy supply markets. Assuming that the institutional barriers discussed in Sections 5.3.2 and 7.3 can be overcome and that the economics of the system are favorable, the HTGR can become a viable substitute for fossil fuels in the generation of process heat. In some cases, it is the only nuclear alternative for high temperature process heat applications and, as such, gives the utility industry the means to supply the future energy demands of various energy-intensive industries with minimal environmental impact and enhanced resource conservation.

The evolutionary potential of the HTGR is illustrated in Figure 4.6-1. The higher temperatures which may be attained with the all-graphite core, inert helium coolant, and thermally insulated concrete pressure vessel inherent to the HTGR cannot be fully exploited by Rankine cycle power plants. The full potential of core outlet temperatures of 850°C to 950°C can be realized through use of the HTGR Gas Turbine power cycle and/or reforming technology. The flexibility of the HTGR is thus enhanced because of the potential for gaining added useful energy at both the high and low temperature regions of the power cycle. The HTGR is, therefore, capable of high plant efficiencies and greater energy utilization, whereas the conventional steam turbine power plant has essentially reached its full development potential.

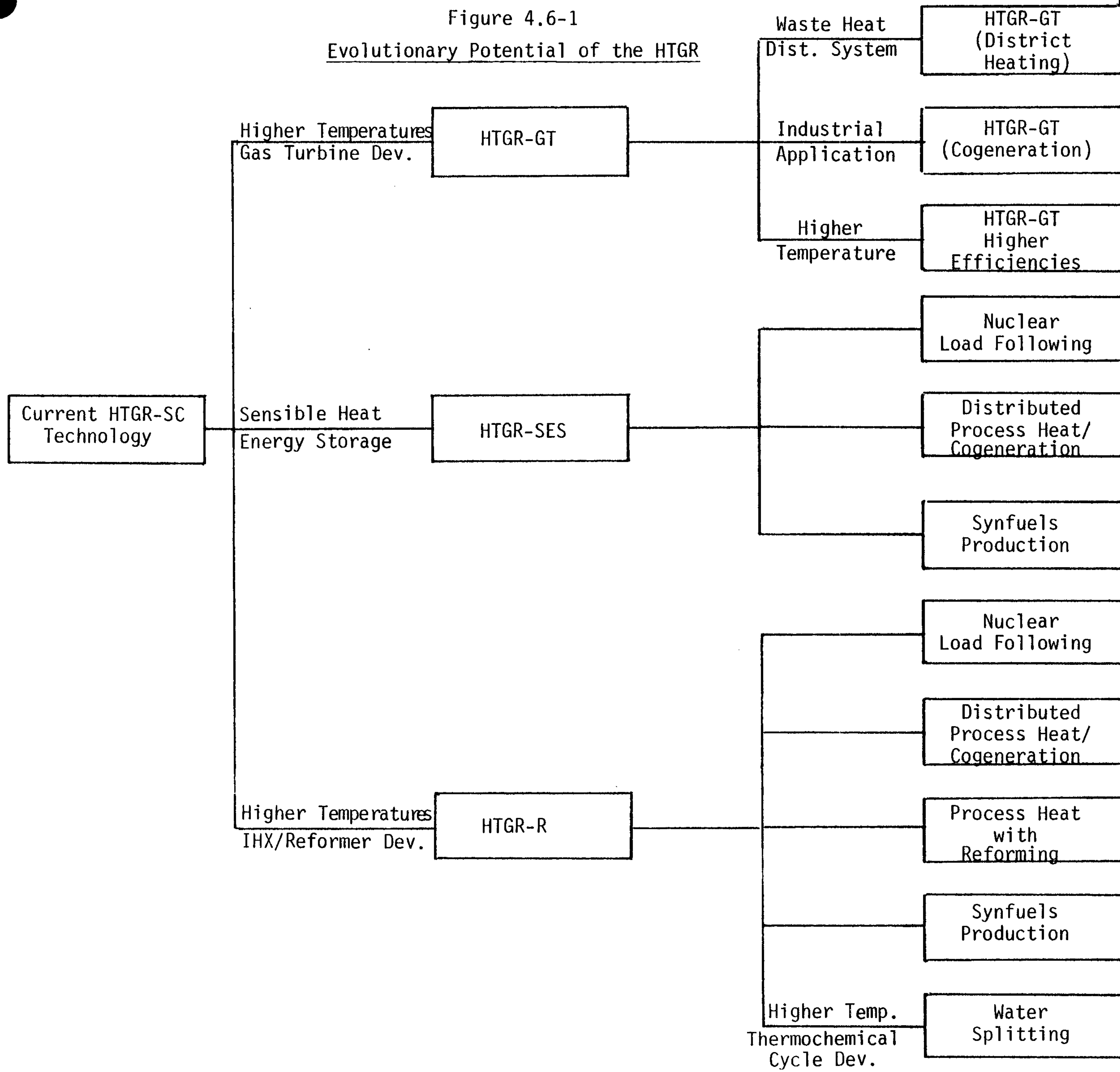
4.6.1 Evolution from the HTGR-SC

Within the present temperature regimes of the HTGR-SC, utilization of a sensible heat storage system may give an added dimension to the flexibility of the HTGR. At present, a system which can be described as an HTGR with sensible energy storage (HTGR-SES) is under study whereby heat from the reactor is transferred to a high-temperature heat transfer salt. This salt is then stored at 540°C to 593°C (1000°F to 1100°F) and later piped to the user. The sensible heat from the plant can be utilized via a heat exchanger either for a direct heat process or to produce steam up to 500°C (950°F). The cooled salt would then be returned to the heat source.

The salt system is currently under investigation as a transfer and storage medium for solar energy systems. It also shows promise

Figure 4.6-1

Evolutionary Potential of the HTGR



when coupled to an HTGR as a storage medium for utility load-following and process heat distribution. For utility load-following, the reactor would run at full power continuously. A certain percentage of the thermal output would be utilized to store heat in the salt, which would be stored on site. During times of peak load, the salt would be drawn from storage and utilized to generate steam, which would run peaking turbines. While this would allow the use of nuclear fuel for the generation of peaking electricity, the economics and the design of the system must be further refined before any conclusions can be drawn about the potential market for its application. As for the use of this concept as a means of process heat distribution, the heat from the reactor would be stored much in the same way as described above. The molten salt could then be piped to industrial users which would extract the heat through heat exchangers. The cooler salt would then be returned to the central station. While the economics for this system have yet to be established, a market does appear to exist for a sensible heat storage system for industrial heat distribution. This aspect is discussed in Section 5.3.2.

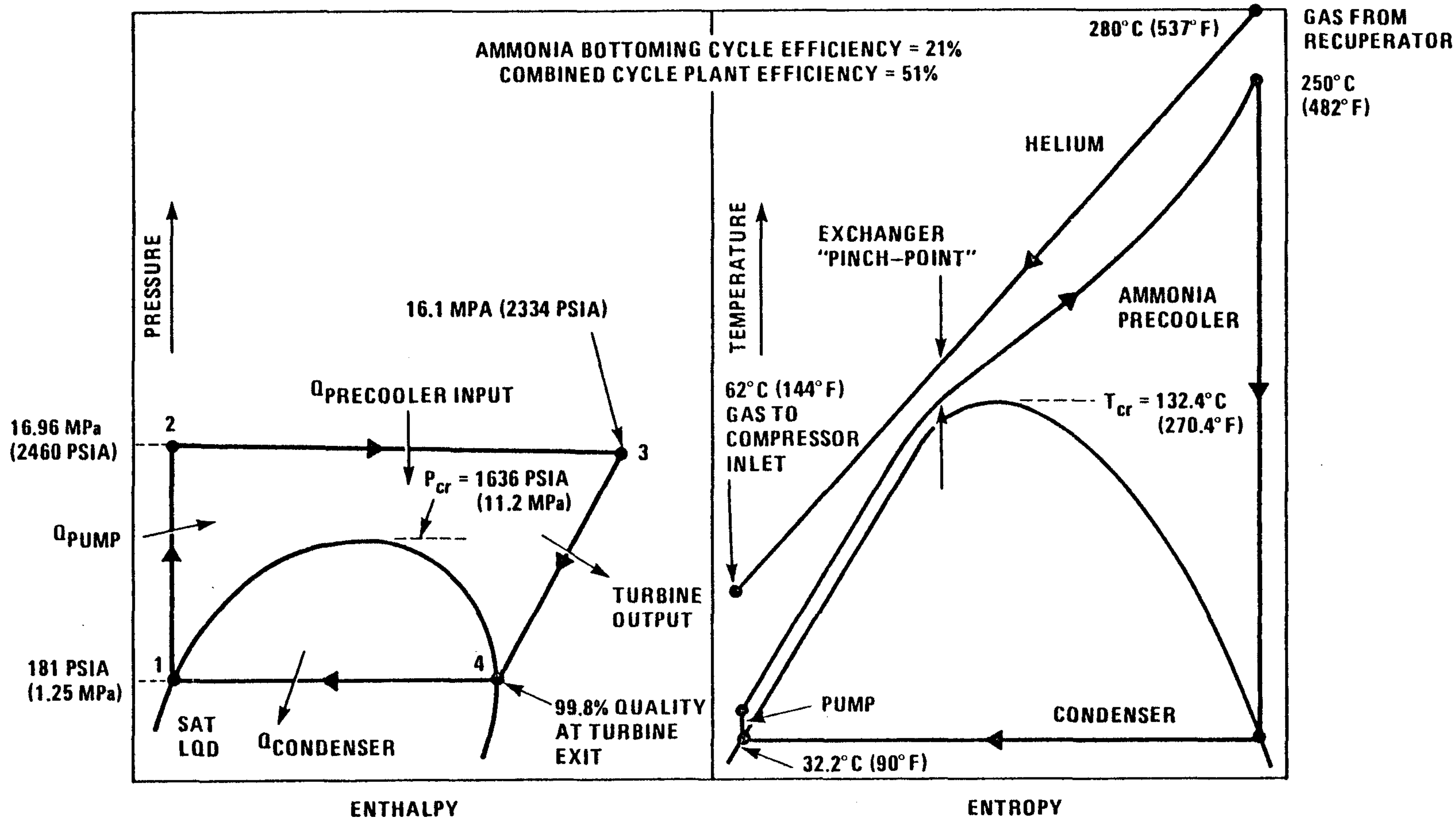
A further significant potential of the HTGR-SES is utilization within the emerging synfuels industry. As in the case of the HTGR-PS/C, a high percentage of input energy requirements (up to about 80% of the total, depending upon the process) can be provided by a heat source which operates in the range approximating 750°C (1382°F). The accessibility of the market is enhanced by the capability to store and distribute energy.

4.6.2 Evolution from the HTGR-GT

The high temperature heat rejection of the HTGR-GT has led to the investigation of alternate energy applications for this relatively high-grade waste heat. It is ideally adapted for use in secondary power cycles or potential conservation applications such as desalination, district heating, and cogeneration.

In the HTGR-GT, higher output may be achieved either through a secondary power cycle or by increased core outlet temperature. Preliminary studies of designs for this secondary power cycle have focused on the use of ammonia and dinitrogen tetroxide (N_2O_4) as two possible working fluids. The evaluations indicated that the N_2O_4 cycle was less desirable than ammonia because of its relative effects on overall plant efficiency when compared to the ammonia cycle. The studies also indicate that by using ammonia, an overall plant efficiency of approximately 50% can be achieved. The cycle diagram for this binary ammonia cycle is shown in Figure 4.6-2 and the flow diagram in Figure 4.6-3. The economic incentive for adding the secondary power loop is not defined at this time. The capital cost of the equipment has not been definitively estimated because ammonia turbines and condensers have not been built, although they do appear to be within the state of the art (Reference 9). The safety issue of the presence of high-pressure ammonia and the possible leakage into the core have also not yet been addressed. In summary, the high efficiency potential of the HTGR-GT can be realized through the use of

Figure 4.6-2

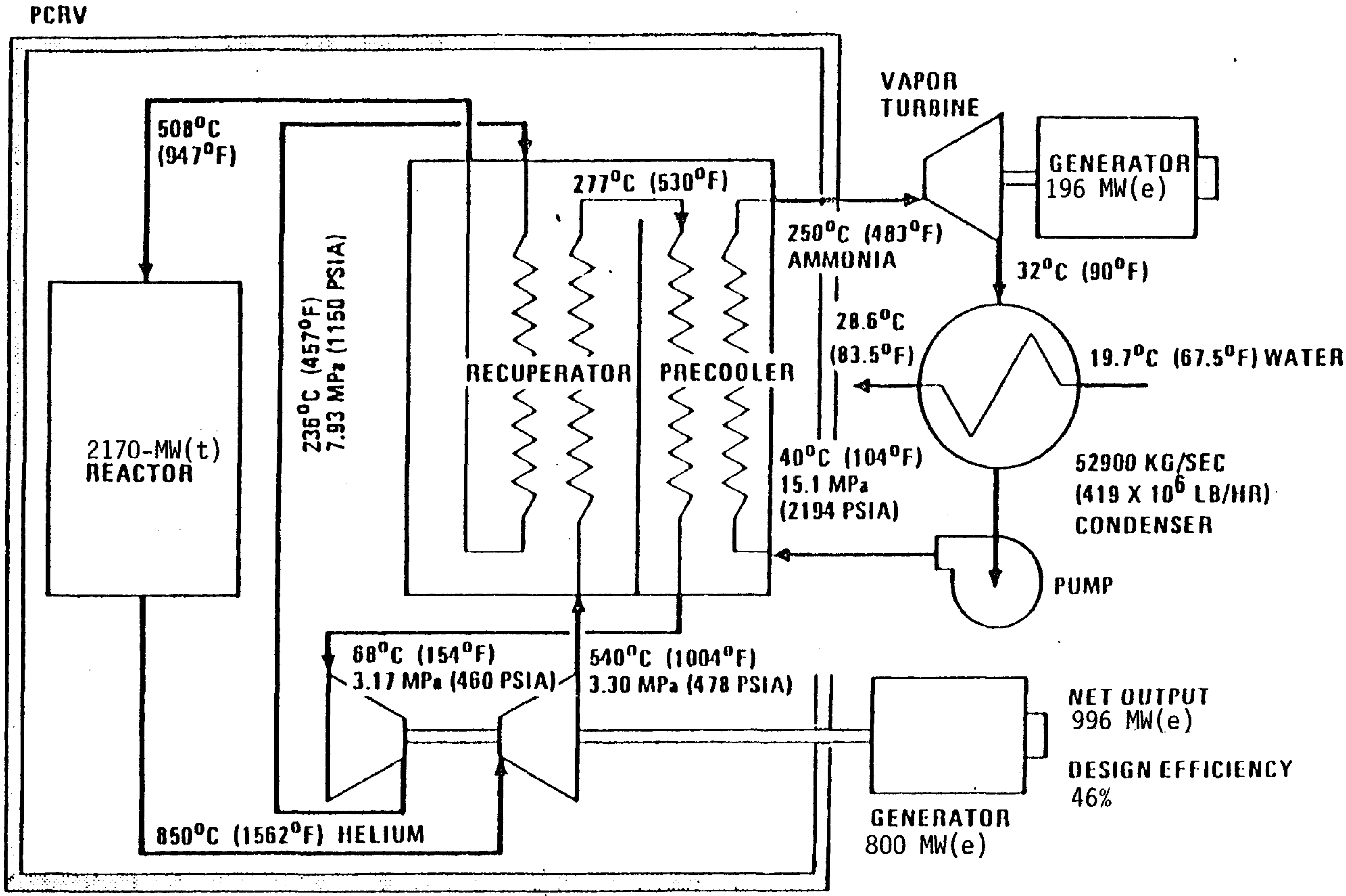


GT-HTGR SUPERCRITICAL AMMONIA BOTTOMING CYCLE DIAGRAM

Source: Reference 9

Figure 4.6-3

BINARY HTGR-GT FLOW DIAGRAM



a secondary power cycle, but the economic incentives to do so remain to be demonstrated.

The other method of increasing the Brayton cycle efficiency is by increasing the turbine inlet temperature. Figure 4.6-4 shows the system efficiency of the HTGR-GT as a function of reactor outlet temperature. The present factors which are limiting the reactor outlet temperature to 850°C are fission product release from the fuel and material capabilities at the higher temperatures for the reactor outlet ducts and the turbine blades. A great deal of work must be done in these areas before the higher core outlet temperatures can be achieved.

With recent emphasis on fuel conservation and reduced environmental impact of power stations, cogeneration with the HTGR-GT by means of a secondary cycle could be an attractive development objective. The additional thermal power from the secondary cycle would be available for the incremental cost of the additional power conversion equipment. To put this in perspective, however, with the exception of several small systems in some cities, the necessary distribution piping systems for this cogenerated energy do not exist and would need to be installed to serve the potential customers. Also, steam and/or hot water can only be transmitted over relatively short distances, which seems incompatible with present-day remote siting requirements for nuclear installations. In summary, the economic and institutional barriers to a distributed process steam or district heating system emanating from a nuclear plant must be quantified and overcome before this potential application of the HTGR-GT can be realized.

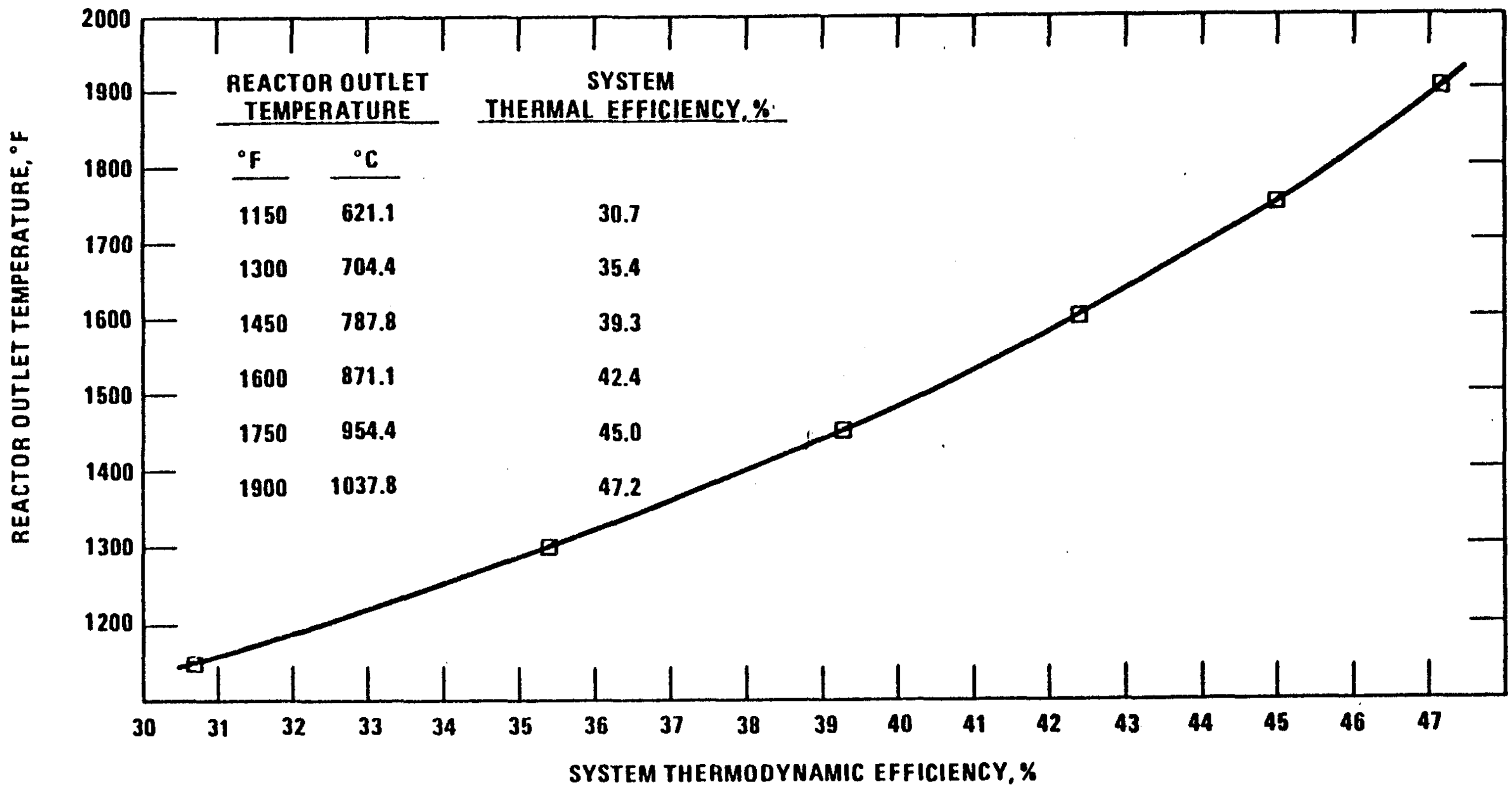
4.6.3 Evolution from the HTGR-R

The current reference design for the HTGR-R and the principles of its operation are presented in Section 7.1. The reference plant utilizes an intermediate helium loop to isolate the reformer from the primary helium loop. The economics of this arrangement are marginal, with a good deal of uncertainty; therefore, the economic incentive may exist to move the reformers into the PCRV and to increase the core outlet temperature to 950°C. The effect that the higher temperature will have on the efficiency of the reforming reaction is projected in Table 4.6-5.

The utilization of the synthesis gas produced by the reformer is presently being examined for various industrial processes. The transportation of the synthesis gas via the Thermochemical Pipeline (TCP) concept offers a novel means of delivering nuclear heat energy, stored by a chemical reaction in the synthesis gas, to a remote user where the energy is liberated via the exothermic methanation reaction. This system is projected to allow transportation over distances up to approximately 100 miles. Figure 4.6-6 schematically presents the TCP concept. This concept is being pursued in the Federal Republic of Germany where a combined reformer and methanator test loop has recently begun operation.

Figure 4.6-4

System Thermodynamic Efficiency as a Function of Reactor Outlet Temperature



Source: Ref. 9

Table 4.6-5

Process Characteristics and Economics of Thermochemical Pipeline as a Function of Peak Reformer Process Temperature

BASIS: H_2O/CH_4 = 3:1; CONSTANT METHANATION CONDITIONS; MIXED FEED EVAPORATOR; 40 ATM PRESSURE; 1000 MWth TRANSPORTED AT PIPELINE CONDITIONS 160 KM TRANSMISSION DISTANCE

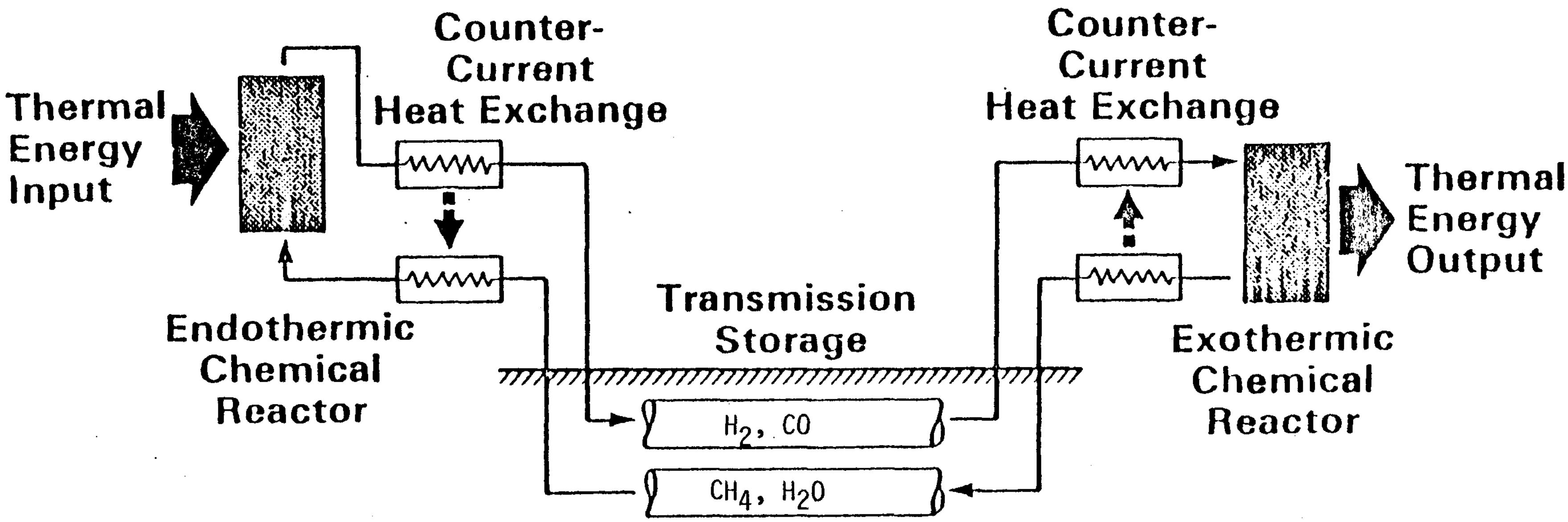
REFORMER TEMPERATURE K (C)	CH_4 CONVERSION %	REFORMER HEAT DUTY MWth	REFORMER HEAT EXCHANGE DUTY MWth	EFFICIENCY* INDEX	INCREMENTAL COST ABOVE HTR HEAT COST $/GJ	TOTAL DELIVERED HEAT COST $/GJ (HTR HEAT @ $2.50/GJ)
1200 (925)	81.9	981	904	88.1	1.26	3.76
1100 (825)	64.8	1003	1239	85.7	1.47	3.97
975 (700)	33.3	1106	2360	80.2	2.10	4.60

*Efficiency index defined as $\frac{\text{Heat Delivered at Methanator}}{\text{Heat Consumed at Reformer + Equivalent Thermal Energy for all work requirements}}$

Source: 'HTR-Synfuel Application Assessment', COO-4057-12, Sept. 1979, General Electric, Sunnyvale, CA.

Figure 4.6-6

CHEMICAL HEAT PIPE (CHP) CONCEPT



An advanced application of the HTGR which is receiving much attention in Japan is the direct reduction process of iron ore for steelmaking. In this process, the reformer product synthesis gas is used to reduce iron ore pellets in a shaft furnace before they enter an electric arc furnace for final refining. A block diagram of the process is shown in Figure 4.6-7. The economics of this process utilizing a 3000 MWt HTGR appear favorable, but a steel mill utilizing this size reactor would produce 15 million tons per year and have a total investment cost of $5.4 x 10^9 in 1979 dollars (Reference 6). This capacity is approximately thirteen times greater than existing conventional mills, thereby making a high capacity factor mandatory for successful economic operation.

The use of the HTGR in the emerging synfuels industry was investigated in detail by Reference 6. Indirect coal liquefaction, coal hydrogasification, direct coal liquefaction, and oil shale processing were all reviewed. The conclusions reached were:

1. The HTGR significantly increases the yield of synfuel product per unit of feed coal or shale. The incorporation of nuclear reforming within synfuels processes using the HTGR-R provides an additional increment in coal utilization relative to the HTGR-SC.

2. Whether this increased yield is used to reduce feed requirements or to increase synfuel production, the cost of the product is approximately equal with or without the HTGR.

3. Reduced consumption of coal, water and land resources as well as reduced emission of pollutants result from use of the HTGR.

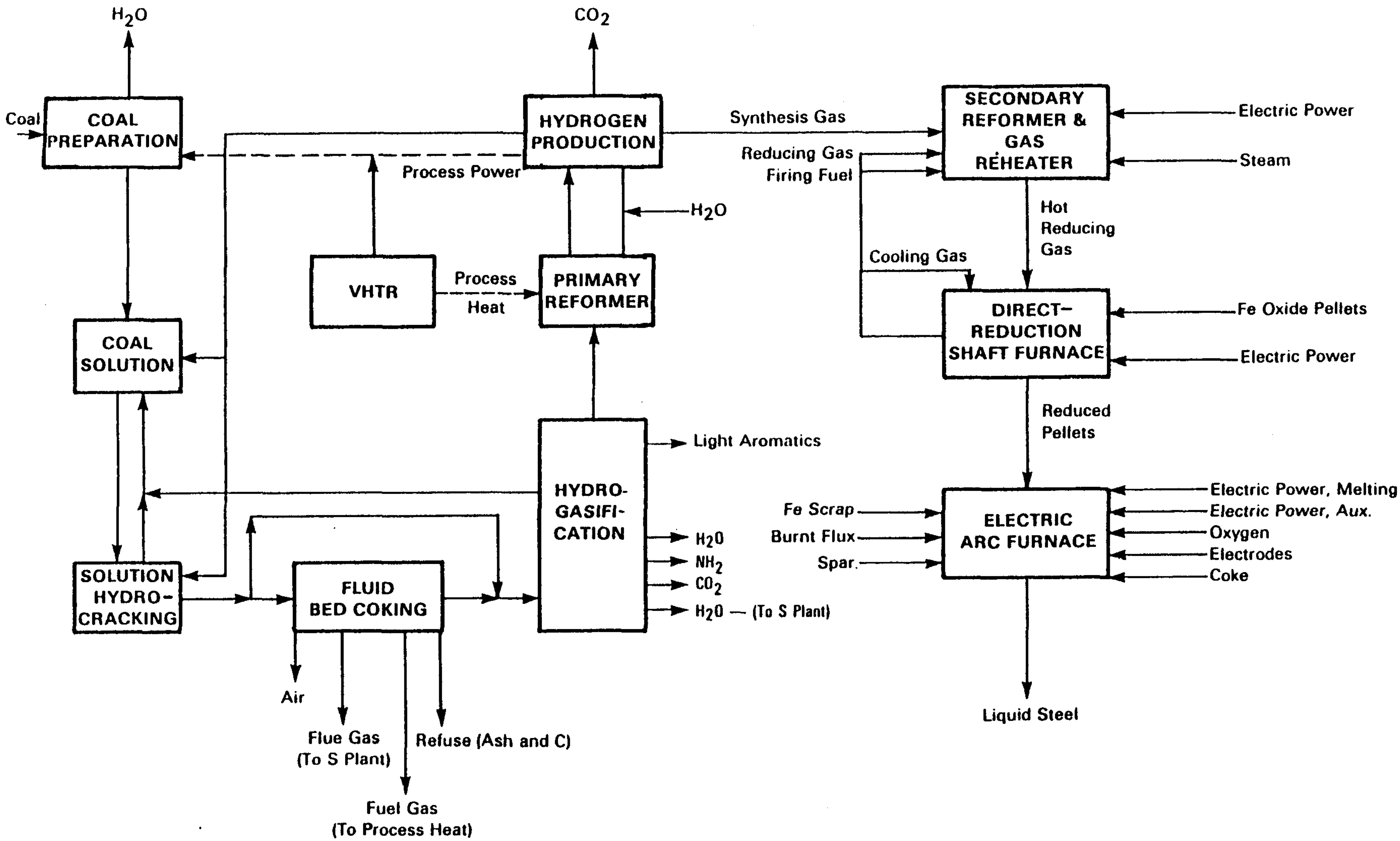
4. The institutional problems involved in application of HTGR's to synfuel production are a major concern and include potential siting and licensing difficulties as well as difficult requirements for financing and ownership arrangements.

If in the future a "hydrogen economy" becomes a reality, investigators have shown that the HTGR can be used to produce hydrogen via the thermochemical water splitting process ($2H_2O \quad 2H_2 + O_2$). Hydrogen is not a cost-effective gas to transmit via a pipeline over long distances because of its heat content (325 BTU/ft^3 vs. 1000 BTU/ft^3 for natural gas). Therefore, the hydrogen would most likely be used in synfuels production and the hydrogen plant would be part of a large synfuels complex. The application of the HTGR in this technology is clearly dependent on the successful development of the water splitting process as well as the demonstration of the 950°C core outlet temperature capability of the HTGR.

In all of the applications mentioned here, it is envisioned that the electric utility industry will be the owner and the operator of the HTGR system. In this capacity, utilities will be able to expand their services into the energy markets of the future. Whether or not institutional barriers will prevent this expension remains an issue for future resolution.

Figure 4.6-7

Simplified Block Flow Diagram for a GA/SWE Synthesis Gas Plant and Direct Reduction/Electric Arc Furnace Steel Process



Source: Reference 6

5.0 THE HTGR STEAM CYCLE

The HTGR Steam Cycle (HTGR-SC) has received considerable attention in the past as a potential energy option for utilities. A technical description is presented in this section which also serves as a detailed description of the systems that are generic to the HTGR-SC, GT, and R. Economic and market assessments are also developed for this HTGR option.

5.1 TECHNICAL DESCRIPTION

5.1.1 HTGR-SC

This section describes the 2240 MWt, 858 MWe HTGR-SC plant which was developed by General Atomic Company as a standard plant design for the generation of electricity via the Rankine Cycle.

The HTGR reactor core is cooled with pressurized helium, moderated and reflected with graphite, and fueled with a mixture of uranium and thorium. It is constructed of prismatic hexagonal graphite blocks with vertical holes for coolant channels, fuel rods, and control rods. The entire reactor core, together with other major primary system components, is contained in a multicavity, prestressed concrete vessel (PCRV). Helium coolant is circulated by four electric-motor-driven circulators through the core and through four main steam generators, each located in separate cavities in the PCRV wall. Superheated steam (2500 psi, $1005^{o}F$) produced in the once-through steam generators is expanded through a tandem compound turbine generator. Steam is condensed in a water-cooled condenser, and waste heat is rejected to the atmosphere in a wet cooling tower. In addition to the four primary coolant loops, three core auxiliary cooling system loops (CACS) are also provided. Each consists of a gas/water heat exchanger with auxiliary electric-motor-driven circulators located in cavities in the PCRV wall. Should the main loops not be available, coolant gas is circulated from the reactor core through the heat exchangers where heat is transferred to the core auxiliary cooling water system (CACWS) for rejection from cooling towers to the atmosphere. The components and systems described above for the nuclear steam supply system (NSSS) are shown in an isometric view of the PCRV in Figure 5.1-1. Figure 5.1-2 shows a simplified schematic diagram of the primary and secondary coolant systems.

The PCRV and ancillary systems are housed inside a reactor containment building which is a conventional steel-lined reinforced secondary containment structure. Typically, balance-of-plant (BOP) systems and equipment are arranged and housed in separate buildings considering function and service. Ten years of spent fuel storage with railroad access for shipping and receiving is provided on site.

Nuclear Steam Supply System (NSSS)

Included in the NSSS for the 2240 MWt HTGR-SC plant are those nuclear, control, and heat transfer systems and components used to generate steam for electric power generation. For design purposes, the NSSS is divided into the following 15 major system categories:

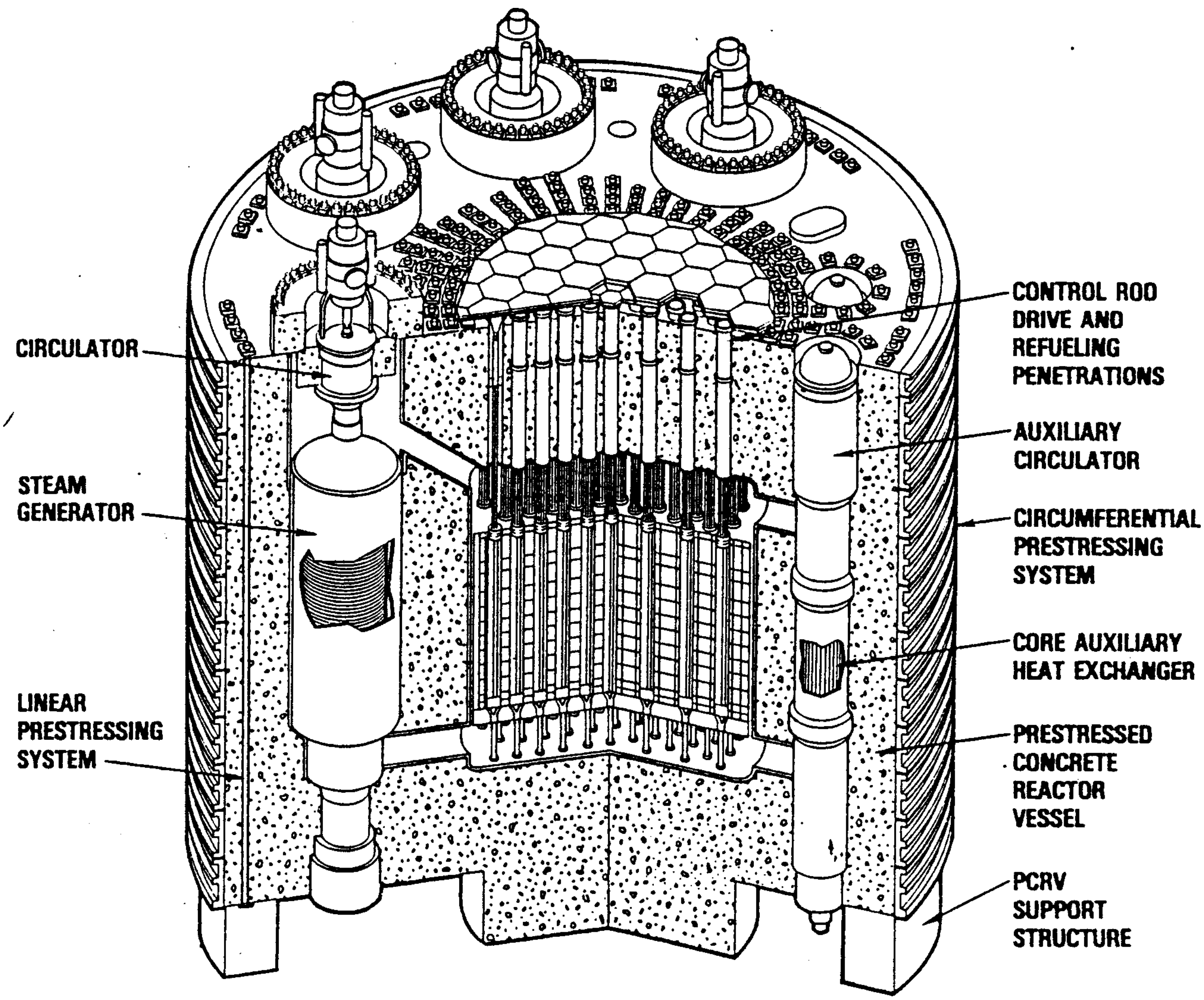
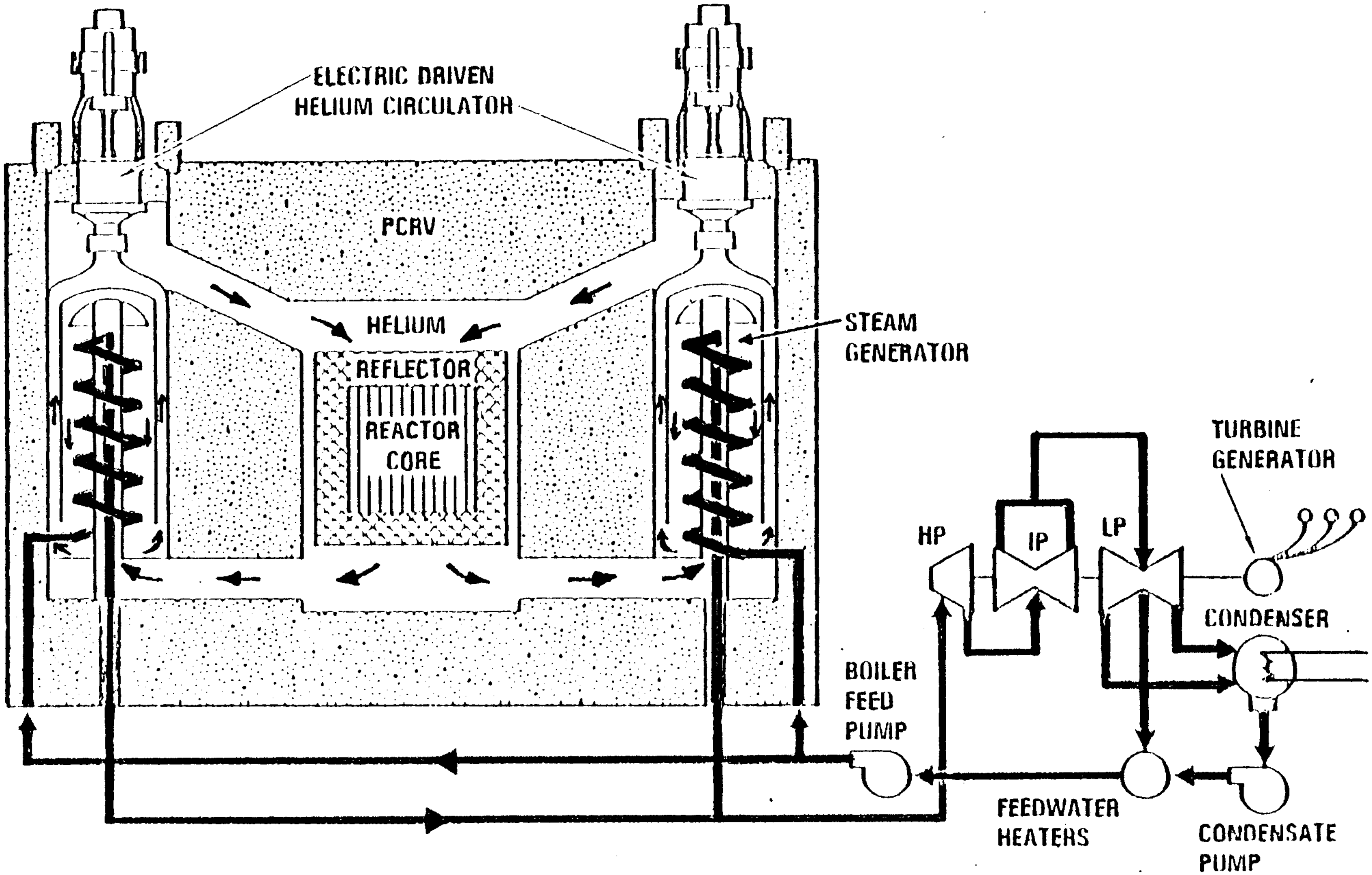


Figure 5.1-1
HTGR Nuclear Steam System

Figure 5.1-2



Schematic Flow Diagram

1. Prestressed concrete reactor vessel (PCRV)
2. Reactor core
3. Reactor internals components
4. Primary coolant
5. Core auxiliary cooling (CACS)
6. Neutron and region flow control
7. Fuel handling
8. Fuel shipping
9. Reactor service equipment and storage wells
10. Main and auxiliary circulator service
11. Helium services
12. Plant protection (PPS)
13. Plant control (PCS)
14. Plant data acquisition, processing, and display (DAP)
15. Gas waste

Significant features and characteristics of these systems are briefly described below:

Prestressed Concrete Reactor Vessel (PCRV) - The PCRV functions as the primary containment for the reactor core, the primary coolant system, and portions of the secondary coolant system. It has a core cavity that is offset from the center of the PCRV by 3.2 m (10 ft.6 in.). The main side cavities which surround the core consist of four steam generator cavities and three core auxiliary heat exchanger (CAHE) cavities. Prestressing is provided longitudinally by vertical tendons and circumferentially by wire strands wound in channels in the outer PCRV walls. A welded carbon steel liner provides a gas-tight primary coolant boundary covering the surfaces of the cavities, ducts, and inside the PCRV penetrations. Penetrations are anchored in the PCRV concrete and are welded to adjacent liners to maintain the continuity of the primary coolant boundary. Each penetration includes a gas-tight closure. Those penetrations with removable closures are fitted with double gaskets, and purified helium is supplied to the annulus between the gaskets at 103 kPa (15 psia) above the upper plenum pressure to assure that any outward leakage will be purified helium. Thermal protection is provided wherever necessary to satisfy the concrete temperature limits. The thermal barrier consists of layers of fibrous blanket insulation compressed against the PCRV liner by metal cover plates. Two independent pressure relief trains are provided, each sized for 100% relieving capacity. This system provides the ultimate protection to limit PCRV maximum cavity pressure to 7892 kPa (1130 psig). Instrumentation is also provided to sense, record, and alarm as required on liner and concrete temperature and strain data, including linear circumferential prestressing loads.

Reactor Core - The reactor core includes the fuel elements, the hexagonal reflector elements, the top layer/plenum elements, and the startup neutron sources.

The fuel element is a graphite block that both contains the fuel and acts as a moderator. Each fuel element consists of a hexagonal graphite block containing drilled coolant passages and fuel channels into which the fuel rods are inserted (Figure 5.1-3). The individual fuel rods contain the fissile and fertile coated particles distributed in a graphite matrix. The initial core elements and the reload elements, whether containing fresh or recycle fuel, are of identical geometry. The fissile particle has a uranium carbide kernel with a TRISO coating. The TRISO coating has four layers: an inner buffer layer of low-density pyrolytic carbon, a thinner layer of high-density pyrolytic carbon, a layer of silicon carbide that provides containment of gaseous and solid fission products, and an outer layer of high-density pyrolytic carbon that adds strength to the coating. The fertile particle has a thorium oxide kernel with a BISO coating. The BISO coating has two layers: an inner buffer layer of low-density pyrolytic carbon and an outer coating of high-density pyrolytic carbon. The latter provides the containment.

There are two types of fuel element: standard and control (see Figure 5.1-3). Both contain arrays of fuel and coolant holes, but the control elements also have holes for the insertion of control rods and reserve shutdown material. Approximately one-seventh of the fuel elements are of the control type.

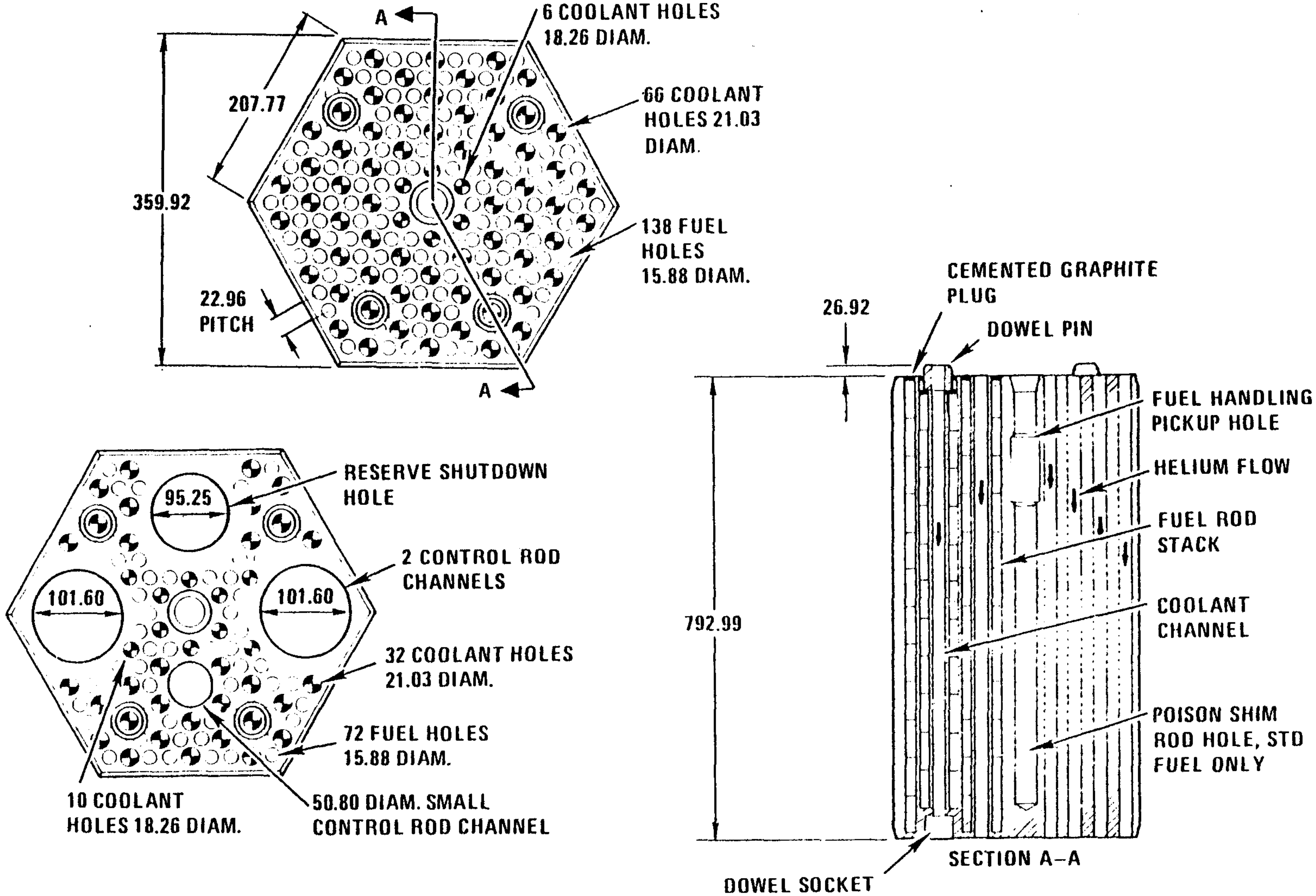
The fuel elements and hexagonal reflector elements are arranged in columns supported on core-support blocks, with each support block normally supporting one fuel region. Each region consists of seven columns of fuel elements, with a central column of control fuel elements and six surrounding columns of standard fuel elements. The fuel regions are surrounded by two rows of hexagonal reflector-element columns, which are in turn surrounded by the permanent side reflector. The reflector elements may have coolant holes, control-rod and reserve shutdown holes, and shielding material as required, but they do not contain fuel. The core for the 2240 MW(t) reference plant is shown in Figure 5.1-4.

In addition, the reactor core contains top layer/plenum elements. These are hexagonal alloy-steel components that provide the flow plenums for distributing the flow from the region flow-control valves to the individual columns. They also provide lateral restraint during refueling, and support for the flow-control valve and lower guidetube assembly.

The startup neutron source is californium-252 in a suitable container. It is inserted into core fuel elements to provide a source of neutrons of sufficient strength to ensure a safe, controlled approach to reactor criticality.

From an economic and resource standpoint, the optimal fuel cycle in the HTGR is the HEU/Th cycle. However, consistent with the government's proliferation-resistant policy, the reference HTGR fuel cycle selected for the initial cores in the reference plant utilizes <20% enriched U-235 with thorium and is designated as an LEU/Th cycle. The reference fuel cycle assumes a once-through cycle with the U-233, bred from thorium, to be stored and to be available for recovery and recycle if this is eventually permitted. The major param-

Figure 5.1-3

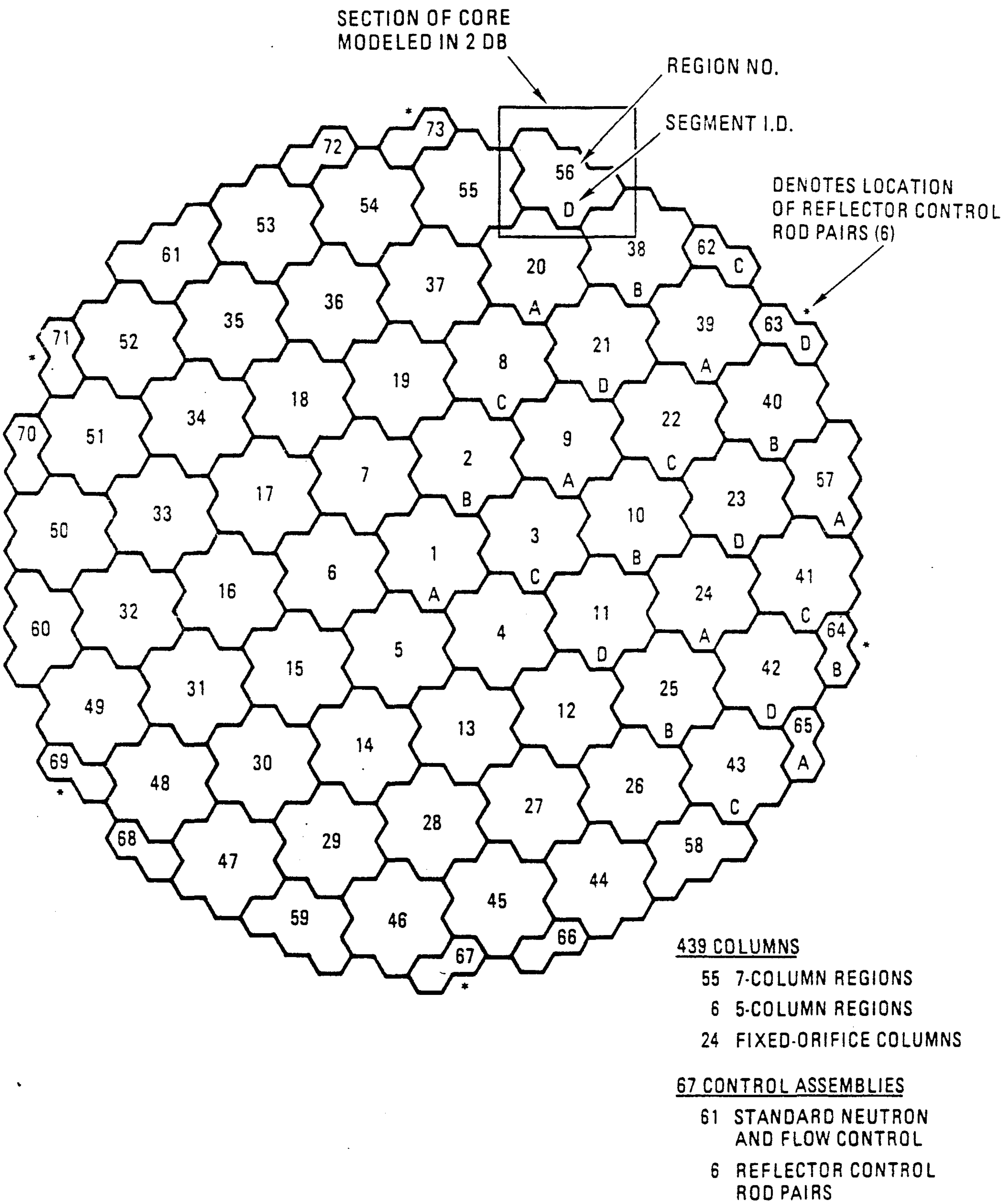


ALL DIMENSIONS IN mm

HTGR fuel element

Source: Reference 25

Figure 5.1-4



Core layout for 900-MW(e) Reference Plant

Source: Reference 25

eters of the reference once-through LEU/Th fuel cycle for the optimized 2240 MWt design are shown in Table 5.1-5.

The reference plant design permits the use of several alternate fuel cycles without major plant modification. A sample listing of fuel cycles which have been studied for this plant are:

- LEU/Th fuel - once-through
- LEU/Th fuel with recycle
  - (a) Recycle HEU-233 only
  - (b) Recycle 12% enriched U-233
  - (c) Recycle U-233
  - (d) Recycle U-233 and re-enriched residual fissile uranium
- HEU/Th fuel with recycle

Reactor Internals Components - The reactor internals system consists of four major components, each of which provides a basic function as follows:

- Core support floor structure provides vertical support of the reactor core and all reflector elements.
- Core lateral restraint provides restraint of the reactor core and all reflector elements during a seismic event.
- Permanent side reflector limits the neutron fluence reaching the components external to the reflector.
- Core peripheral seal provides a controlled bypass leakage in the annular space between the permanent side reflector and the PCRV liner.

Primary Coolant System - The primary coolant system consists of the subsystems and components required to transfer heat from the reactor core to the secondary coolant system. The overall system flow and heat balance and performance data are shown in Figure 5.1-6 and Table 5.1-7. The major system components are the steam generator, the main helium circulator, and the helium shutoff valves.

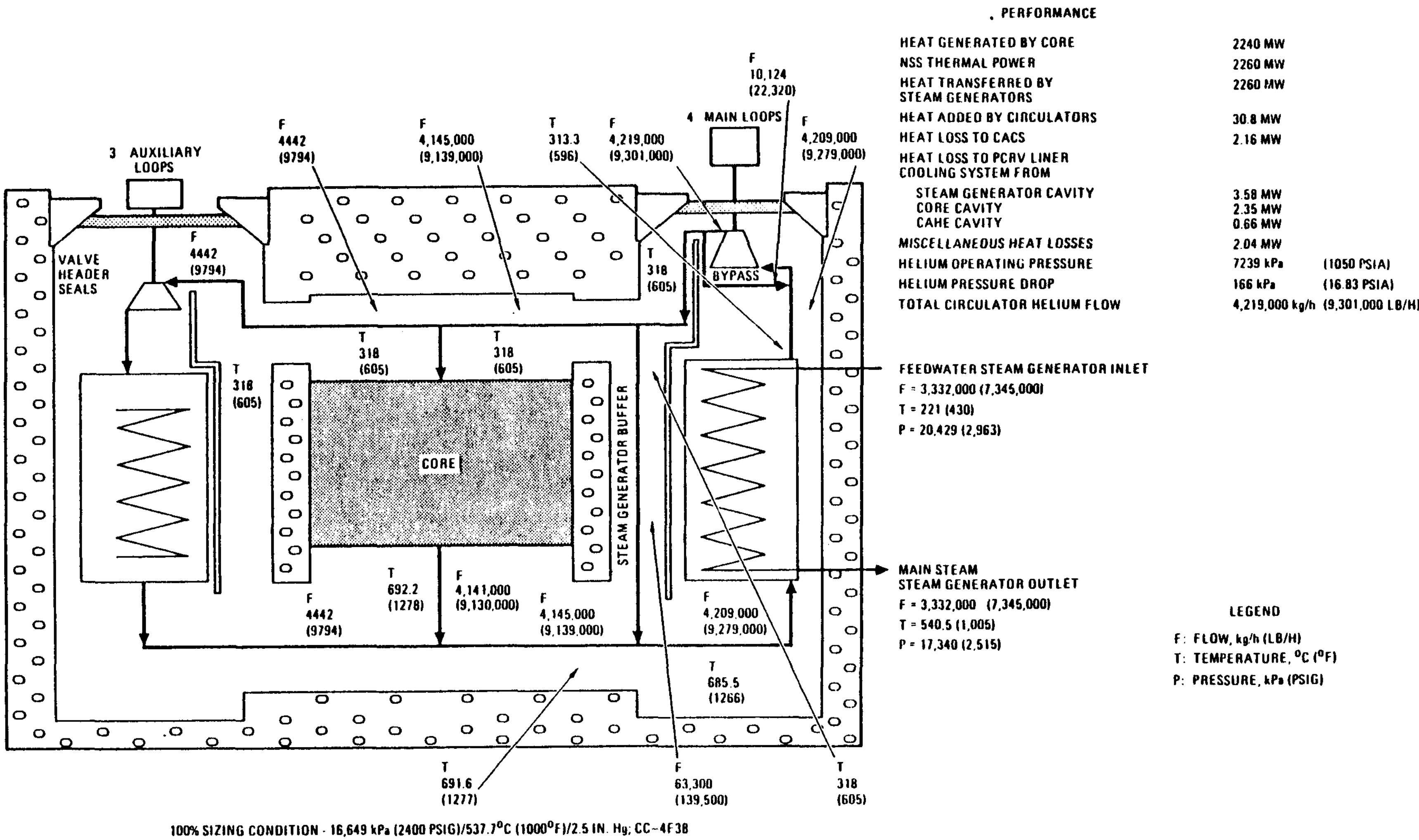
The primary coolant system uses a constant inventory of helium to transfer heat from the reactor core to the steam generators. The system utilizes four steam-generator modules in series with four helium circlators situated in cavities within the PCRV. The primary-coolant helium is forced downward through the reactor core by the four helium circulators, which derive their power from variable speed electric motors. The helium leaves the core through the core-support blocks, traverses the lower plenum, and enters the four steam-generator crossducts, from which it flows upward over the steam-generator surfaces and enters the circulator inlet diffuser to

Table 5.1-5

Reference Fuel Cycle
for the HTGR-SC 2240 MWt Reference Plant

Fuel	20% enriched uranium with thorium
Core power density	7.1 W/cm^3
Fuel lifetime	4 years
Refueling cycle time	1 year
C/Th ratio at equilibrium	600
Fissile material	UC_2; UCO or UO_2 are promising alternates
Fertile material	ThO_2
Conversion ratio	0.60
Fast fluence	6.5×10^{25} n/m^2
Burnup	105,000 MWd/MT

Figure 5.1-6



900-MW(e) Reference Plant heat balance diagram

Source: Reference 25

Table 5.1-7

2240 MWt HTGR-SC NSS Performance Parameters

Number of primary coolant loops	4
Reactor power, MWt	2240
Heat losses, MWt	10.8
Thermal power to NSS from circulator, MWt	30.8
NSS thermal power, MWt	2260
Station auxiliary power, MWe	
Power to helium circulator motor (and controller)	35
Other auxiliary NSS power	1.2
Helium inventory (total), kg (lb)	13,382 (29,500)
Helium inventory (circulating), kg (lb)	8,936 (19,700)
Helium flow rate, kg/h (lb/h)	4,219,233 (9,301,300)
Helium pressure at circulator discharge, kPa (psia)	7,235 (1,050)
Total primary circuit ΔP, kPa (psi)	116 (16.83)
Reactor core, core support block, and orifice ΔP, kPa (psi)	51 (7.41)
Steam generator ΔP, kPa (psi)	51.1 (7.42)
Core inlet gas temperature, ^oC (^oF)	318 (605)
Steam generator inlet gas temperature, ^oC (^oF)	686 (1266)
Circulator inlet gas temperature, ^oC (^oF)	314 (597)
Core power density, MW/m^3	7.15
Steam flow through steam generators, kg/h (lb/h)	3,331,795 (7,344,944)
Final feedwater temperature/pressure, ^oC/kPa (^oF/psia)	221/20,415 (430/2,963)
Steam generator outlet steam temperature/pressure, ^oC/kPa (^oF/psia)	541/17,328 (1005/2,515)

complete the circuit. The entire system is contained within the PCRV.

The temperature of helium is measured at the exit of each core-support block. This temperature is controlled by adjusting the core-region flow-control valve or control-rod configuration. Main steam temperature is used for automatic regulation of the control rods.

Core Auxiliary Cooling System (CACS) - The CACS is an engineered safety system incorporated in the HTGR design for reactor core residual and decay heat removal. The system, installed in the PCRV, consists of three auxiliary coolant loops, each having a variable speed electric induction motor driven auxiliary circulator, an auxiliary shutoff valve, and a water-cooled heat exchanger. The CACS's function is to provide a separate independent means of cooling the reactor core with the primary system pressurized or depressurized. Each loop is capable of cooling the core following loss of main primary loop circulation and reactor trip from full rated power conditions with the PCRV pressurized. Any two loops can cool the core under the same conditions with the PCRV at containment building atmospheric pressure.

The CACS is maintained in a standby mode with water circulation through the CAHEs when the main loops are in operation. This ensures readiness of the system.

Neutron and Region Flow Control System - The neutron and region flow control system consists of the neutron control subsystem and the primary coolant flow control subsystem. The mechanical components of these subsystems are located primarily in the refueling penetrations in the top head of the PCRV.

The neutron control subsystem comprises: (1) the normal flux control and reactor shutdown system, which includes neutron detectors, power rods, and control rod pairs; (2) the reserve shutdown system (RSS); (3) the movable in-core flux mapping unit system; and (4) the movable startup detector system. The primary coolant flow control subsystem consists of variable orifices and drives and helium outlet temperature thermocouples for each core region.

The neutron and region flow control system utilizes out-of-core flux detectors and controllers, power rods, control rods, and/or reserve shutdown material to adjust core reactivity as required to meet the demands of the plant control system, the plant protection system, or the plant operator. The system also regulates the helium flow distribution through regions of the core by incrementally positioning each core region inlet orifice valve when commanded by the plant operator.

Fuel Handling System - The fuel handling system consists of all the equipment and subsystems required for the remote handling of both fuel and reflector elements. Major equipment items comprising this system are a fuel handling machine, fuel transfer casks, an auxiliary service cask, refueling equipment positioners, fuel transfer casks dollies, a refueling equipment transporter, reactor isolation and floor valves, fuel container loading equipment, a control station, and a fuel sealing and inspection facility. This system handles both new and used fuel between its in-core location and delivery to the fuel storage facility.

Refueling operations are predicated on a 4-year core life, with one-quarter of the reactor core being replaced with new fuel each year; replaceable reflector elements that reside adjacent to active fuel elements are replaced at 8-year intervals. Each refueling region, consisting normally of seven columns of fuel and removable reflector elements, is entirely emptied of spent fuel before the placement of new fuel.

A new in-vessel refueling concept has recently been defined for all HTGRs. This scheme has a refueling plenum located above the core inlet plenum. Refueling equipment for handling and moving fuel and reflector elements is placed into this plenum during refueling. Spent fuel elements removed by the fuel handling machine are transported horizontally to the side of the core cavity by a conveyor located in the refueling plenum; elevators then lower the spent fuel elements to a temporary fuel storage vault beneath the PCRV and then bring new elements from the storage vault to the refueling plenum where they are then inserted into the core by the fuel handling machine. The spent fuel elements remain in the helium-filled vault for several months after refueling until the decay heat drops to an acceptable level. The spent fuel and reflector elements are then transferred to the fuel sealing and inspection facility where they are sealed in helium-filled containers which are subsequently placed in storage for shipment.

Fuel Shipping - The spent and recycle fuel shipping system consists of rail equipment designed to transport spent fuel elements to the storage facility and/or the recycle plant. This equipment is also designed to ship recycle fuel elements from the recycle plant.

The rail shipping system consists of a spent fuel cask, a rail car, and fuel shipping containers. The cask has an inner basket that holds 12 fuel shipping containers. Each fuel shipping container holds 6 spent fuel elements or 5 recycle fuel elements within protective packaging. The cask body and the cask closure is shielded with depleted uranium.

Reactor Service Equipment and Storage Wells - This system is a collection of equipment used to service selected areas of the reactor plant. Equipment involved is the wire winding machine, the control rod drive turntable, the circulator handling equipment, the in-core thermocouple service equipment, core service tools, and service facility tools.

Main and Auxiliary Circulator Service Systems - The principal function of the circulator service systems is to provide a supply of high-pressure water for helium circulator bearing lubrication and cooling. The circulator motor requires a separate oil lubricant supply subsystem. Additionally, the service system supplies purified buffer helium to the circulator labyrinth seals for preventing in-leakage of bearing water to the primary coolant system or outleakage of primary coolant. In the case of the main circulator service system, it also supplies high-pressure helium to actuate the circulator static seals, which must close when the circulator is stopped to maintain the primary system boundary.

Helium Services System - The helium services system consists of two functional systems: the helium purification system and the PCRV seal system. The helium purification system is a closed-loop system which removes primary coolant from the PCRV and returns the helium to the PCRV as a purge essentially free of activity and chemical impurities. The PCRV seal system is a static pressurization system for sealing PCRV penetration closures. The seal system also provides a means for leak testing PCRV closures.

Plant Protection System (PPS) - The plant protection system provides for safe operation or shutdown in the event of abnormal or accident conditions. This system prevents unacceptable release of radioactivity by initiating automatic actions that protect the fission product barriers or that limit releases if failures should occur in these barriers. The PPS has the following subsystems: reactor trip, steam header isolation and dump, main loop shutdown, CACS initiation, PCRV relief block valve interlock, rod bank withdrawal interlock, CAHE isolation, moisture monitoring, and containment isolation. Three redundant divisions of the PPS are provided.

Plant Control System - The plant control system provides for safe automatic plant operation by regulating reactor power and controlling NSS steam conditions in a reactor-follow-turbine mode. The system responds to electrical load variations by varying feedwater flow, neutron flux, and circulator speed to maintain steam conditions constant over the normal range of plant load. The system also provides automatic actions for protection of major components and protective actions during certain incidents which would result in the need for the PPS.

Plant Data Acquisition, Processing and Display System (DAP) - The DAP system is a dual-computer-based, non-safety-related interface between the plant instrumentation and the plant operator. Redundancy of computers and critical peripheral equipment is provided for maximum availability.

The system provides the plant operator with information that will increase efficiency in operating the plant, will protect plant equipment, and will warn the operator of equipment degradation through annunciation of alarm conditions. It also can provide historical data for use in analysis of plant performance and diagnosis of equipment malfunctions.

Gas Waste System - The radioactive gas waste system collects all radioactive gaseous wastes generated in the plant, excluding PCRV and other equipment leakage. The system provides for sampling and processing for controlled disposal of radioactive and potentially radioactive gas wastes. Gas wastes which require processing for either radioactivity removal or helium recovery are compressed to high pressure and transferred to the helium purification system for processing.

Balance of Plant (BOP)

Structures, equipment, and systems not supplied as part of the NSSS are identified as BOP. For design and accounting purposes, the BOP is typically broken down into about 6 major categories, i.e., structures and improvements, turbine plant equipment, electric plant equipment, miscellaneous plant equipment, waste heat rejection system, and reactor plant balance-of-plant systems. Much of the BOP is based on current subcritical large power plant design practice.

The design of the turbine plant is based on a single tandem-compound, six flow turbine-generator with no moisture separation or reheat. The turbine-generator converts 2260 MWt steam generator thermal output (2240 MWt core thermal output) to approximately 913 MWe gross electrical output for a net station output of 858 MWe. The turbine plant includes a full flow condensate polishing system, six stages of feedwater heating, and two half-size turbine-driven boiler feed pumps. Main steam lines from each of the four steam generators penetrate the containment and are headered in the turbine building. For startup, shutdown, and other conditions of off-normal operation, a main steam bypass to the condenser is provided. A closed cooling water system is provided to remove waste heat from all turbine plant components. This system is cooled by service water from the waste heat rejection system. The heat sink for the main thermal cycle and all plant service water during normal plant operation is assumed to be a conventional wet cooling tower for the reference plant design. Alternate waste heat rejection systems may be considered depending on specific site conditions and resources.

The electric plant control systems are based on generator rotation speeds of 3600 rpm similar to fossil plants. The on-site electrical power system, consisting of three safety-related diesel generators and DC batteries and one non-safety-related diesel generator, is designed to provide power to the safety-related NSSS loads in the event of a loss of off-site power.

A safety-class nuclear service water system supplies cooling water for the essential reactor plant cooling water system, fuel handling and storage cooling water systems, and other reactor plant auxiliaries during emergency conditions. This system consists of two independent redundant trains that reject heat to separate auxiliary wet cooling towers.

The core auxiliary cooling water system (CACWS) provides a closed-loop supply of cooling water to the core auxiliary heat exchangers so that reactor decay heat is removed from the primary coolant and rejected to the atmosphere by air blast heat exchangers. Each of the three independent cooling water loops is normally in a standby mode and only activated upon loss of main loop cooling capability.

Buildings and enclosures for the plant are divided into the categories of Seismic Category I and non-Seismic Category I. Seismic Category I structures house all safety-related systems and equipment essential for safe plant operation, shutdown, and control. These are generally massive reinforced concrete structures. The reactor containment building (RCB) is a steel-lined, reinforced concrete cylinder with a hemispherical dome and circular base mat. The design pressure is 60 psig. The reactor service, fuel storage, and control auxiliary and diesel generator buildings are major structures adjacent to the RCB for functional arrangement of operation and service to the NSSS. Ten-year fuel storage is provided on site, and the facility is capable of handling either truck or rail shipping of spent fuel.

5.1.2 HTGR-PS/C

A variant of the HTGR-SC plant described in Section 5.1.1 presently being considered as a lead plant option is the HTGR Process Steam/Cogeneration Plant (HTGR-PS/C). It is envisioned as a central, baseloaded steam plant, rated at 1170 MWt, which is capable of serving multiple users in a localized chemical/refinery complex to replace existing small in-plant oil- and gas-fired facilities. The design of the 1170 MWt HTGR-PS/C is a two-loop version of the HTGR-SC plant. The reference design for the 1170 MWt HTGR-PS/C applies the primary steam (2500 psi/1005°F) to a high-pressure turbine rated at approximately 140 MWe. Output steam from this turbine (650 psi/1670°F) is available for process requirements. This particular balance is compatible with the steam requirements for the chemical/refinery industry. However, a wide range of process steam applications up to 2500 psi/1005°F are available while continuing to cogenerate electricity. Figure 5.1-8 shows the heat balance diagram for the reference design. Table 5.1-9 shows the expected HTGR-PS/C performance parameters.

The components and systems of the NSSS for the HTGR-PS/C are as described in Section 5.1.1. An assessment of the current state of the technology and design of the HTGR-SC is presented in Reference 40.

5.2 ECONOMIC ASSESSMENT

One of the roles of GCRA in the HTGR Program is to evaluate the relative power cost economics of the HTGR and to inform its membership of the results. Also, as stated in Section 2.1, economics is one of the principal factors in the utility decision process for the selection of a major capital expenditure. In this section, current economic data will be

Figure 5.1-8

1170 MWt HTGR - PROCESS STEAM/COGENERATION MULTI-PURPOSE HEAT BALANCE DIAGRAM

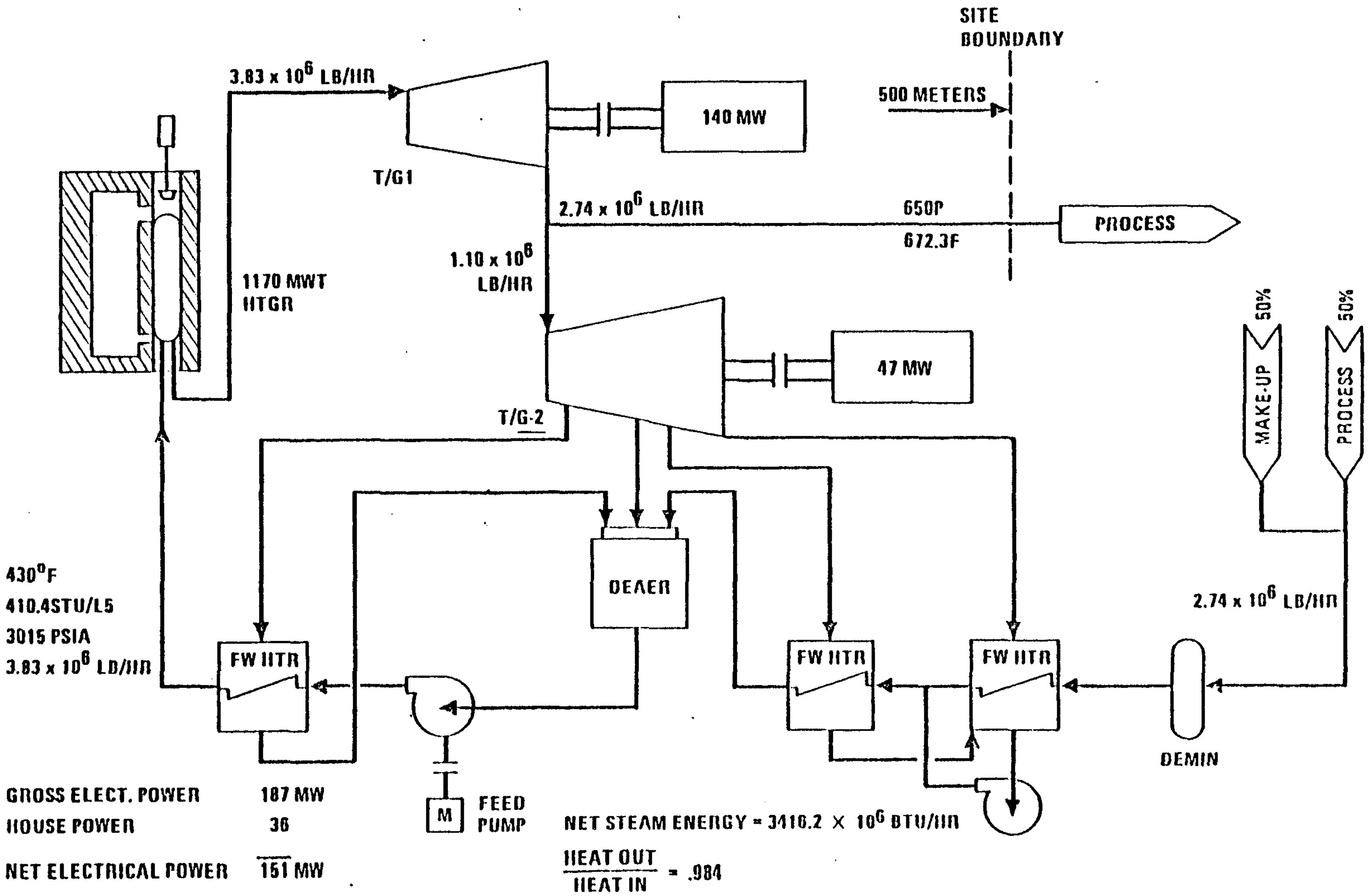


Table 5.1-9

1170 MW(t) HTGR-PS/C Expected Performance Parameters

NUMBER OF PRIMARY COOLANT LOOPS	2
REACTOR POWER - MW(t)	1170
COGENERATED NOMINAL ELECTRICAL OUTPUT (NET) - MW(e)	150
TOTAL PRIME STEAM FLOW - LB/HR	3.8×10^6
COGENERATED PROCESS STEAM FLOW - LB/HR	2.7×10^6
COGENERATED PROCESS STEAM TEMPERATURE - °F	672
COGENERATED PROCESS STEAM PRESSURE - PSIA	650
HELIUM FLOW RATE - LB/HR	4.7×10^6
HELIUM PRESSURE AT CIRCULATOR DISCHARGE - PSIA	1050
CORE INLET GAS TEMPERATURE - °F	605
STEAM GENERATOR INLET GAS TEMPERATURE - °F	1266
CORE POWER DENSITY - MW/m^3	6.2
FEEDWATER INLET TEMPERATURE - °F	430
SUPERHEATER EXIT PRESSURE - °F	1005
FEEDWATER INLET PRESSURE - PSIA	3015
SUPERHEATER EXIT PRESSURE - PSIA	2515

presented based on estimates which have recently been completed or which have been updated from previous studies.

HTGR-SC

Table 5.2-1 presents cost data for the reference HTGR-SC plant. It is compared against similarly sized coal and LWR plants. The costs of all three plants were estimated using the same economic ground rules, which are given in Table 5.2-2. All estimates were performed by United Engineers & Constructors based on their experience with design of all three plant types and are applicable for the commercial equilibrium plant; therefore, they contain no first-of-a-kind costs. The NSSS cost estimate for the HTGR was supplied by General Atomic Company. While the actual dollar amount shown for a specific plant type may not be equal to current total installed costs, the estimates do present a valid comparative analysis of total plant costs for each of the three plants examined relative to each other because common estimation techniques were used.

Based on the estimates and designs that have been completed to date, the total cost of power produced by the HTGR-SC is essentially equal to the cost of power produced by the LWR. Even if HEU/Th with full recycle is utilized in the HTGR and LEU with recycle in the LWR, the total power cost advantage for the HTGR-SC is projected to be only 2.7%. This differential must be considered to be inside the uncertainty bandwidth of the estimate. A preliminary accuracy bandwidth for the present capital cost estimate is -10% to +25%, which is based on the design status of the previous reference 3360 MWt HTGR-SC (Reference 26) on which the most engineering of any HTGR system has been completed. This design base is being utilized in the design of the 900 MWe reference HTGR-SC.

As indicated above, the costs presented in Table 5.2-1 represent estimates for an equilibrium commercial plant. No first-of-a-kind or development costs have been included. A discussion of the magnitude and types of development costs associated with the commercialization of the HTGR-SC can be found in Reference 40. The possible arrangements for the distribution and recovery of these development and first-of-a-kind costs are discussed in Reference 36.

HTGR-PS/C

A cost comparison between the HTGR-PS/C and a coal-fired cogeneration plant is presented in Table 5.2-3. These estimates are based on the same ground rules that were used for the HTGR-SC. The LWR was not included in this comparison because oil-fired superheaters are required to produce steam conditions comparable to those produced by the HTGR.

The comparison indicates that the HTGR can produce energy via process steam at a 30% to 43% cost advantage over the coal plant, depending on the nuclear fuel cycle. It must be understood that this advantage is a function of the assumptions used in the study. For example, the cost of coal-fired cogenerated steam is very dependent on the cost of the coal. It can be seen from Table 5.2-3 that the fuel cost for the coal-produced steam in Case 1 accounts for 78% of the total energy cost while for the HTGR

Table 5.2-1

HTGR-SC Cost Comparison

	HTGR-SC	PWR	COAL
PLANT PARAMETERS			
POWER RATING - MWt	2240	2400	2200
NET ELECTRICAL OUTPUT - MWe	858	800	800
EFFICIENCY (%) (WET COOLED)	38.3	33.0	36.4
PLANT COSTS (x 10^6)			
TOTAL DIRECT COST ('80 $)	545	509	412
INDIRECT COST ('80 $)	213	227	85
TOTAL BASE CONSTRUCTION COST ('80 $)	758	736	497
$/KWe ('80 $)	883	920	621
ESCALATION	748	736	562
INTEREST DURING CONSTRUCTION	477	442	212
TOTAL INVESTMENT COST ('95 $)	1983	1914	1271
$/KWe ('95 $)	2311	2392	1588
POWER COSTS (MILLS/KW-HR) ('95 $)			
CAPITAL	68	70	47
O&M	14	14	16
FUEL LEU/Th (20%) - ONCE-THROUGH	37	38	96
CASE 1 - TOTAL	119	122	159
FUEL HEU/Th (93%) - RECYCLE	27	30	
CASE 2 - TOTAL	109	114	
COOLING SYSTEM COST ADDERS*			
100% DRY COOLING	14	17	14
DRY/WET - 115 x 10^6 GAL/YR	7	11	7
DRY/WET - 500 x 10^6 GAL/YR	5	9	5
100% WET COOLING	0	0	0

*REFLECTS COOLING SYSTEM CAPITAL PLUS OPERATIONAL PENALTIES FOR COOLING SYSTEM PERFORMANCE AT TYPICAL ARID SITE: MODESTO, CALIFORNIA.

Table 5.2-2

HTGR-SC and PS/C Cost Assumptions

Commercial Plant Basis	Nth Plant
Base Date for All Costs	1/80
Date of Commercial Operation for All Plants	1995
Book Life for All Plants	30 yrs.
Plant Levelized Capacity Factor (All Plants)	70%

Fuel Costs Input Data (1/80 $)

Coal	
Range	\$0.70 - 1.60/MBTU
Average	\$1.36/MBTU
Uranium	
1990	45 \$/lb U_3O_8 ('80 \$)
2000	45
2010	75
2020	120
2030	120

Tails 0.2%
Conversion \$5/KG
Enrichment \$100/SWU

Financial Factors

Discount Rate	10%
Fixed Charge Rate	18%
Interest During Const. (Simple)	10%
Escalation	
Labor and Materials	6%
Coal	8%
Power Credit	8%

Fuel Cycle Costs are based on a detailed analysis by GAC.

O&M Costs were developed based on information described in ORNL Report "A Procedure for Estimating Nonfuel Operation and Maintenance Costs for Large Steam-Electric Power Plants."

Comparative Alternatives

- PWR - Extrapolated 800 MWe design from Reference 1200 MWe design developed by UE&C
- Coal - Reference 800 MWe Base Loaded Coal Plant developed by UE&C
  - Reference 1230 MWt Cogeneration Coal Plant developed by UE&C

Table 5.2-3

HTGR-PS/C Cost Comparison

	HTGR-PS/C	COAL
PLANT PARAMETERS		
POWER RATING - MWt	1170	1230
NET ELECTRICAL OUTPUT - MWe	150	157
PROCESS FLOW (LB/HR)	2.7×10^6	2.7×10^6
PLANT COSTS ($\times 10^6$)		
TOTAL DIRECT COST ('80 $)	413	313
INDIRECT COST ('80 $)	178	67
TOTAL BASE CONSTRUCTION COST ('80 $)	591	380
ESCALATION	598	433
INTEREST DURING CONSTRUCTION	373	162
TOTAL INVESTMENT COST ('95 $)	1562	975
ANNUAL ENERGY PRODUCTION		
TOTAL TO PROCESS (10^6 BTU/YR)	20.9×10^6	20.9×10^6
NET ELECTRICITY (10^6 KWe-HR)	920	963
ENERGY COSTS ($/$10^6$ BTU) ('95 $) (PROCESS STEAM PIPING EXCLUDED)		
CAPITAL	13.3	8.4
O&M	3.0	3.3
FUEL LEU/Th (20%) - ONCE-THROUGH	5.1	14.3
CREDIT FOR ELECTRIC POWER SOLD (22 MILLS/KWe-HR)	(7.5)	(7.8)
CASE 1 - TOTAL	13.9	18.2
FUEL HEU/Th (93%) - RECYCLE	3.9	
CASE 2 - TOTAL	12.7	
ENERGY COST TO PROCESS ($/$10^6$ BTU) ('95 $) (PROCESS STEAM PIPING INCLUDED*)		
CASE 3 LEU/Th (20%) - ONCE-THROUGH	15.8	
CASE 4 HEU/Th (93%) - RECYCLE	14.6	

*5 MILES FOR NUCLEAR, 1 MILE FOR COAL

fuel cost accounts for only 37%. This results in increased sensitivity to coal price fluctuations for the coal-based system. If coal prices do not rise as quickly as assumed in the study, the differential between the HTGR and coal will shrink. However, if the coal prices escalate faster than the assumed 2% real escalation per year, this differential will increase. Note that the coal prices shown are projected on the basis of a large central station cogeneration plant. Coal prices associated with smaller AFB coal facilities would be considerably more expensive, and the HTGR-PS/C would have a substantial economic advantage relative to such systems.

Another measure of the sensitivities of these results is shown by Cases 3 and 4 in Table 5.2-3, where increased transmission costs for the HTGR are taken into account. Because of its nuclear heat source, it is assumed that the HTGR will have to be sited further from the customer than the fossil heat source. The effects of this remote siting assumption are to decrease the energy cost differential to 18% and 27% for a four-mile incremental transmission distance, depending on the fuel cycle scenario.

Based on this and other cogeneration studies that have been done, the HTGR-PS/C is generally the economic choice over other heat sources, including fluidized bed combustors (Reference 27), for supplying process steam. However, the results of these studies also indicate that each potential application must be examined based on site-specific parameters and local energy cost projections. Therefore, it is not possible to arrive at a general conclusion with regard to the economic incentives of the HTGR-PS/C.

5.3 MARKET ASSESSMENT

Based on discussions with many potential HTGR owners and users, GCRA has concluded that the only deployment route for any commercial HTGR system will be through the electric utilities. Section 2.1 of this report presented the factors which the utility industry uses to evaluate alternatives for major capital expenditures. By evaluating each of the HTGR systems relative to these factors as has been done in this Assessment, the marketability and hence the market potential of the HTGR can be determined. While this market forecast must be inherently subjective because of the various factors that are examined and weighed, it does present a complete evaluation of the HTGR from the utility/owner perspective and gives a realistic view of the potential HTGR market.

5.3.1 Electrical Generation

The following is a review of the market factors of Section 2.1 and how they specifically relate to the use of the HTGR-SC for the generation of electricity.

Forecasted Energy Demand

Based on the results of Section 2.2.1, the projected market size for nuclear power plants between 2000 and 2020 is expected to be approximately 430 GWe. It is beyond the scope of this document to predict a market penetration rate for the HTGR during this time frame. It can be concluded, however, that 430 MWe of nuclear capacity represents a substantial potential market for the HTGR-SC and, therefore, Forecasted Energy Demand is considered to be a positive market factor.

Siting Flexibility

Sections 4.2 and 4.3 examined the aspects of the HTGR which affect its siting flexibility. Based on the results of those sections, the HTGR-SC can be sited at least as easily as any other nuclear plant. Because of its advantages in water utilization and its radiological characteristics, the potential for increased siting flexibility does exist. This potential will not be acknowledged by the potential market until the regulatory process has had the opportunity to pass judgment on the merits of these potential advantages. Overall, this market factor is considered to be positive for the HTGR-SC.

Technical Development Status

A detailed discussion of the technical status of the HTGR-SC is presented in Reference 40. The proposed 2240 MWt lead HTGR-SC plant represents a doubling in reactor size from the Fort St. Vrain design. In the competitive marketplace for the 430 GWe of nuclear capacity, the HTGR will be competing against coal and LWR technology which will have a very large advantage in years of operating experience. As a result, this market factor must be considered to be negative for the HTGR-SC.

Regulation and Licensing

Section 4.1 examined the licensing issues which remain to be resolved for the HTGR-SC. Based on this review, it does not appear that any major issues exist that could cause major licensing delays. The costs to resolve these open licensing issues, however, have not been estimated, nor can they be until a full-scale regulatory review is undertaken. The GCRA pre-review licensing program is designed to minimize the impact of such a review by providing continuous regulatory feedback into the design process.

Because the regulatory authorities have not had the opportunity to conduct an in-depth review of the current HTGR-SC design, design criteria and regulatory guides have not been generated which pertain to the unique aspects of the HTGR. Based on the proliferation of regulations as the result of LWR operating experience, it is expected that the HTGR will also cause new regulations to be written concerning its design and operation. The magnitude of the regulations should be considerably less than has been experienced with the LWR due to the generic nature of many of the existing regulations. Overall, it is expected that after the lead plant has been constructed and operated, and if the institutional siting problems cited in Section 4.3.3 can be resolved, this market factor will have a positive effect on the HTGR's marketability.

Commercial Status

The HTGR-SC was commercially available in the U.S. for a brief period in the early 1970s. General Atomic Company withdrew the HTGR from the commercial marketplace in 1976 because of the economic uncertainties of that time period. Because of this previous commercial status, it has been difficult to obtain significant government, and to some extent utility, involvement in the HTGR-SC program. The present GAC position on the HTGR is presented in Appendix B. Assuming the present effort succeeds in building a lead plant in the mid-1990s, the industrial manufacturing base for the HTGR components will still need to be established. Table 5.3-1 shows the manufacturing facilities that will need to be available to support a commercial HTGR-SC venture. Because these facilities will not be available instantaneously at the start of the commercialization period, a limited market introduction rate will result.

The commitment of the system supplier to the HTGR will greatly affect the utility industry's perception of the HTGR's commercial status. The prospective owners will require contractual assurances as to the availability of field and home office technical assistance and support during the life of the plant as well as the availability of fuel and spare parts. Because the commitment and/or ability to fulfill these requirements is not readily apparent at the present time, this market factor must be considered as negative.

Plant Capabilities

The operational capabilities of the HTGR-SC under normal operating conditions have been demonstrated by Peach Bottom I and Fort St. Vrain and were discussed in Section 4.4.1. The expected HTGR slow core heatup under accident conditions, which is the result of the inherent high heat capacity of the core, is an increasingly important advantage of the HTGR over the LWR. This capability provides added plant protection against operational transients. As a result, this market factor is considered to be positive for the HTGR-SC.

Economics

The economic analysis of Section 5.2 showed that the total cost of power produced by the HTGR-SC and by the LWR is essentially equal. While it is true that a level of uncertainty exists in the cost estimates for the HTGR, the magnitude of these uncertainties is considered within the uncertainties that exist due to project management related costs for any power system. Based on the above, economics is considered a neutral market factor for the HTGR-SC.

Capital Risk

The events at Three Mile Island II indicate the susceptibility of the large capital investments in an LWR plant to short-term transient conditions. The inherent design of the HTGR provides protection of the investment in the plant by allowing longer operator response times to plant transients. For this reason, this is a positive nuclear market factor for the HTGR.

Table 5.3-1

NSSS Manufacturing Facility Requirements for HTGR-SC
(18-GW/yr capacity)

Critical Components	Shop Type	Shop Availability
PCRV Tendons	U	Available
PCRV Tendon Wrap Machine	G	Available
PCRV Liners and Closures	P	Modify current shops (4 GW); build new facilities (14 GW)
Steam Generator	H	Modify current shops (4 GW); build new facilities (14 GW)
Auxiliary Heat Exchanger	P	New facility
Main and Auxiliary Circulator	G	New facility
Fuel Handling and Service Machines	P	Modify current shops (3 GW); build new facilities (15 GW)
Reactor Internals, Thermal Barrier, Lateral Supports	G	New facility
Control-Rod Drive Assembly	G	New facility
Graphite Supply	U	Included in fuel fabrication investment
Graphite Machining	G	Included in fuel fabrication investment

Legend:

G - General purpose shops
H - Heavy machinery
P - Precision shops
U - Unique materials

Source: Reference 32

Safety

Using the AIPA results presented in Section 4.1, the relative safety of the HTGR-SC can be evaluated. These probabilistic risk assessment (PRA) techniques provide a quantitative measure of plant safety. Based on these analyses, safety is a positive nuclear market factor for the HTGR-SC.

Personnel Radiation Exposure

Section 4.4.2 examined the projected and the experienced HTGR personnel exposure data. Based on that analysis, this market factor is considered to be positive for the HTGR-SC.

Fuel Cycle Flexibility

The performance of the HTGR relative to this nuclear market factor was examined in Section 4.5. While this factor is not currently a concern for utilities because of the present Administration's commitment to the once-through fuel cycle, it is expected that fuel cycle flexibility will become a major advantage to the HTGR in the early 21st century. For these reasons, this is considered a positive nuclear market factor for the HTGR-SC.

Advanced Applications

The advanced applications of the HTGR serve to provide an incentive for the commercialization effort by exposing the unique markets which the HTGR may ultimately be able to serve. Because the advanced applications potential will be a positive factor in securing government support to the Lead Project, this must be considered a positive market factor in the time frame of this Assessment.

Summary

Overall, the HTGR-SC appears to have a large potential market in the 2000-2020 time frame. All of the identified market factors are positive or neutral except for Technology Development Status and Commercial Status. The HTGR program that is under way is addressing the former factor. The Commercial Status must become acceptable to the utility market through the use of contractual agreements, warranties, service and fuel commitments, and cost- and risk-sharing arrangements. This remains to be the single most important barrier to the marketability of the HTGR-SC.

5.3.2 Process Steam/Cogeneration

The application of the HTGR for the cogeneration of electricity and steam creates expanded potential market areas for HTGR-SC technology. This section will examine the market factors of Section 2.1 relative to this application.

Forecasted Energy Demand

Based on the results of Section 2.2.2, a substantial market appears to exist for industrial steam. By 2020, a total requirement of 3.37×10^{16} BTUs of steam for industrial processes in major utility service areas is projected (Reference 33), compared with a present usage of 8.2×10^{15} BTUs. 3.37×10^{16} BTUs converts to 9.9×10^{9} MW hr, which means that when a 75% plant capacity factor is assumed, 1500 GWt of steam generation capacity will be required in 2020. This compares to a total capacity of 730 GWt which is predicted to be in place by 2000. The total market then, excluding replacement capacity, will be approximately 770 GWt between 2000 and 2020.

While this represents a rather large potential market, other factors will reduce the portion of this market that will be available to central station steam generation. The first of these factors is load size. Approximately 76% of all industrial plants require less than 0.5 MWt of process heat capacity, and 99% require 20 MWt or less. This means that in order for a large central station nuclear plant to serve small, dispersed loads, the economics of scale require that a large number of these small loads must be supplied from the single, large plant. This results in a large steam distribution system which, because of economics and the nature of steam thermodynamics, must be constrained in distance to within approximately ten miles (Reference 34) from the heat source. This results in the requirement to have a large number of customers located within approximately ten miles of the site of the plant; therefore, an industrial park type of arrangement must exist.

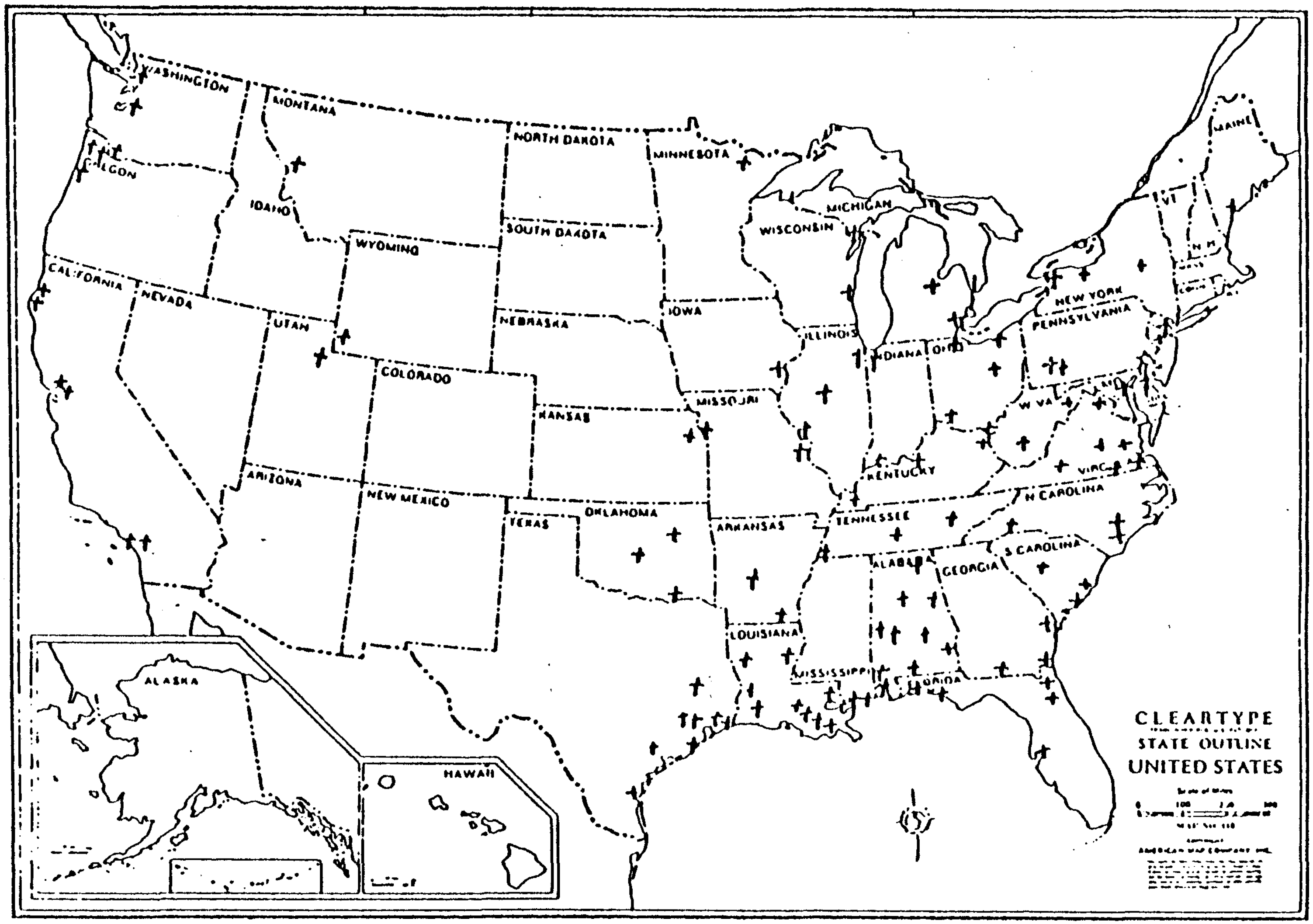
A second factor which will affect the portion of the market available to central station steam generation is the customers' load factors. Approximately 82% of all industrial plants operate at or below one shift/day for six days/week, while only 2% operate more than 2 shifts/day for 7 days/week (Ref. 33). This type of a load profile for a large central station steam plant would result in unacceptably high product costs as the plant would essentially have an average capacity factor usually below 40%. In order to overcome this cyclical load profile, load-leveling measures would need to be taken such as energy storage or time-of-day rates which would encourage off-peak-hours usage.

For the above reasons, the market for central station steam production will be represented by highly concentrated industrial areas. Oak Ridge National Laboratory (ORNL) performed a study (Reference 35) to identify sites where sufficient steam requirements currently exist to justify their further consideration as a potential site for an HTGR-PS/C plant. A summary of these sites is presented in Appendix C and their locations are shown in Figure 5.3-2. All of these sites have an industrial steam demand of at least 500,000 lb/hr within a two-mile radius, but the steam temperature requirements for these sites are at or below 450°F and, therefore, represent a market which can also be served by the LWR. The 500,000 lb/hr steam flow rate is peak, not continuous, and load profile data are not avail-

Figure 5.3-2

Locations with Industrial Steam Demand of at Least 63 kg/s (500,000 lb/hr) Within a 3.2 km (2-Mile) Radius

ORNL-DWG 76-7037



Source: Reference 35

able. The conclusion that can be drawn from this study is that there are areas of industrial concentration that appear to be potential sites for a nuclear central station cogeneration facility. However, the load factors of the various potential customers may not lend themselves to the economic utilization of the proposed facility unless an energy storage system is utilized which will allow the facility to operate continuously at or near full load.

Overall, Forecasted Energy Demand is expected to be a positive market factor for the HTGR-PS/C.

Siting Flexibility

As has been shown previously in this report, the HTGR has the potential for increased siting flexibility over other nuclear systems because of its radiological and water utilization characteristics. The major competitor of the HTGR-PS/C, however, will be coal-fired boilers, most likely in the form of fluidized bed combustors (FBC). This serves to nullify the radiological advantages of the HTGR and, in fact, may act to its detriment because of the reduced siting regulations for fossil-fired facilities relative to nuclear. These regulations translate into more difficult as well as more remote siting for the nuclear unit. Present Environmental Protection Agency regulations may also provide impediments to FBC siting as the limitations for total emissions from air quality districts are approached. These will definitely serve to limit conventional coal plant siting, but their effect on the FBC cannot yet be determined.

The water utilization advantage of the HTGR will not be of importance because water will be consumed to generate steam for transmission. Even though closed-loop steam sytems with condensate return are possible to conserve water, the effect on the water quality of the condensate due to its use by the customer is considered to be a major problem area for the utility as water chemistry must be strictly controlled to prevent steam generator fouling.

A third parameter in the examination of this market factor is the size of the facility. While the reference HTGR-PS/C is 1170 MWt, its competitor, the FBC, will be available in 50-MWt modules which can be added together as additional capacity is needed. Because of its size, the FBC will be able to be sited closer to the load and will require less land.

Overall, Siting Flexibility is a neutral market factor for the HTGR-PS/C because of the present institutional uncertainties that exist.

Technical Development Status

The technical status of the HTGR-PS/C is the same as for the HTGR-SC relative to its competition. For this reason, this is considered to be a negative market factor.

Regulation and Licensing

As with the HTGR-SC, the nuclear regulations pertinent to the HTGR-PS/C have not been fully developed. As for the FBC, only environmental regulations will apply. Because the FBC is expected to meet the more stringent emission standards, licensing or regulatory obstacles are not likely to have a major impact on FBC costs or deployment. Relative to the LWR, however, the HTGR-PS/C has the potential for reduced licensing impact. For these reasons, this market factor must be considered as neutral for the HTGR-PS/C at the present time until these institutional issues are resolved.

Commercial Status

As is the case with the HTGR-SC, the HTGR-PS/C is not commercially available. Prototype FBCs are now in operation and commercial availability is expected within the next 5-7 years. For this reason, this is a negative market factor for the PS/C.

Plant Capabilities

Even though the FBC will be a less complex plant to operate, its maintenance costs and outage rates are expected to be higher than the HTGR, at least during the early years of commercial experience. Both plants will produce high-quality steam with a need for minimum operator attention, and both units are projected with the same lifetimes. Overall, this market factor is considered to be neutral.

Economics

As shown in Section 5.2, the economics of the HTGR-PS/C are strongly site-dependent because of the distance limitations of steam transmission and the load profiles of the steam customers. Based on present capital cost uranium and coal price projections, it appears that the HTGR-PS/C will have an economic advantage over the coal-fired boilers in certain specific locations. However, due to the immaturity of both of the competing technologies and the institutional uncertainties discussed below, economics must be considered as a neutral market factor for the HTGR-PS/C.

Nuclear Specific Market Factors

While the HTGR-SC utilizes these nuclear market factors to its advantage against the competing LWR systems, the HTGR-PS/C must compete against a fossil system which does not require evaluation against these factors. As a result, these can be considered at best to be neutral factors. In certain situations where the industrial loads are also located close to large population areas, the fact that it is a nuclear heat source will result in a negative evaluation of the HTGR-PS/C relative to the fossil heat source.

Institutional Factors

Because of the uniqueness of the HTGR-PS/C as a nuclear heat source for the generation and transmission of process steam, several institutional factors will play a major role in the determination of the viability of the HTGR-PS/C concept. The potential market is composed of electric utilities which would cogenerate electricity and process steam for sale to their customers. The emerging trend in cogeneration is, however, for industrial plants to generate steam for in-plant processes and to cogenerate the electricity to be utilized within the plant or to sell it to the serving utility. This is representative of the trend towards smaller, decentralized systems for process heat generation. This trend is not conducive to the introduction of large central station steam supply systems.

Several other major institutional factors must also be considered when assessing the potential market for the HTGR-PS/C. They include:

Reliability Requirements - A reliability level for steam flow of 98-99% is required for major users of industrial steam (Ref. 35). A premium has been put on this high reliability requirement by providing considerable on-line excess capacity. Loss-of-production rates of 1.9% were experienced in the survey area due to planned and unplanned outages. Nuclear system outage rates would necessarily be much higher. As a result, additional excess capacity would be needed for each customer to provide the required reliability of supply. This excess capacity can be provided either through other central station facilities, which would be uneconomic for a small distribution system, or with small local oil- or gas-fired units which are less capital-intensive and, therefore, more economic when utilized as a backup supply.

Contractual Arrangements - Under utility ownership, both electricity and steam will be produced by the HTGR-PS/C. The electricity will be sold to the customers via the existing transmission network. The steam must be sold to industrial customers at a rate which will allow the utility to obtain the regulated rate of return on its investment in the steam portion of the plant and the transmission pipeline. Before a utility would be willing to commit to construction of such a plant and pipeline, customer commitments would have to be obtained which would assure sufficient revenue to the utility to achieve its rate of return. When this requirement is coupled with the fact that the lead time for any nuclear plant is at least 12 years, it follows that industrial customers would need to make contractual commitments 10-15 years in advance of their service date, which is not compatible with industrial planning horizons. Alternatively, the nuclear plant would have to be designed to utilize a high fraction of its energy for electrical production in the initial period of use, later evolving to a larger fraction of process heat as industrial use grows. Included in these contractual arrangements would be provisions for amortization of the costs of the back-up energy source and the assignment of the capital and fuel costs to one of the parties. Utilities do not normally incur liability for loss of service; therefore, legal precedent must be set for this type of arrangement.

The implications of the above are that the formulation of suitable financial arrangements between the utility and the customer offers substantial obstacles to be overcome before implementation of this type of system can take place.

Licensing - Some of the licensing issues such as nuclear siting near population areas have been discussed previously. The trend toward more remote nuclear siting will have a negative effect on the marketability of the HTGR-PS/C. Another licensing issue yet to be examined is the transmission of steam produced in a nuclear steam generator to offsite customers. Because the steam generator is located in the primary coolant loop, a tube failure could introduce radioactivity into the steam. The relatively inexpensive addition of reboilers may be a technical solution to this problem, but in any case, appropriate isolation and radiation monitoring devices will be required as well as new regulations.

Summary

While a sizable market for process steam is expected to exist between 2000 and 2020, the negative market factors of siting flexibility, technology development status, regulation and licensing, and commercial status will all have a negative impact on the marketability of the HTGR-PS/C. The uncertain or limited economic advantage of the HTGR-PS/C is not strong enough to create a strong demand-pull market situation. However, if an economic sensible energy storage system can be developed and is utilized in conjunction with the HTGR-PS/C to provide a high plant capacity factor and increased service reliability, then the economic incentives for the HTGR-PS/C may create substantial market interest. As a result, even though the above factors offer formidable barriers to commercialization and deployment of the HTGR-PS/C, the projected demand for economic industrial process energy may create a situation which will force timely resolution of the technical, commercial, and institutional problems.

6.0 THE HTGR GAS TURBINE

6.1 TECHNICAL DESCRIPTION

The HTGR Gas Turbine (HTGR-GT) plant described herein employs a 2000 MWt heat source with a prismatic core and fuel configuration similar to the HTGR-Steam Cycle design. The nominal electrical output of this plant is 800 MWe. The two-loop, 2000 MWt HTGR-GT reference plant represents a modification of a three-loop, 3000 MWt HTGR-GT plant design. Among the reasons cited for selecting the two-loop plant are simplified turbomachinery removal and replacement, substantial reduction in isolated phase bus duct requirements, reduced prestressed concrete reactor vessel (PCRV) complexity, and utility plant size preferences. The plant design will reflect specific GCRA functional requirements and objectives and is intended to be a standard replicable reference plant design of the HTGR-GT concept.

General Description

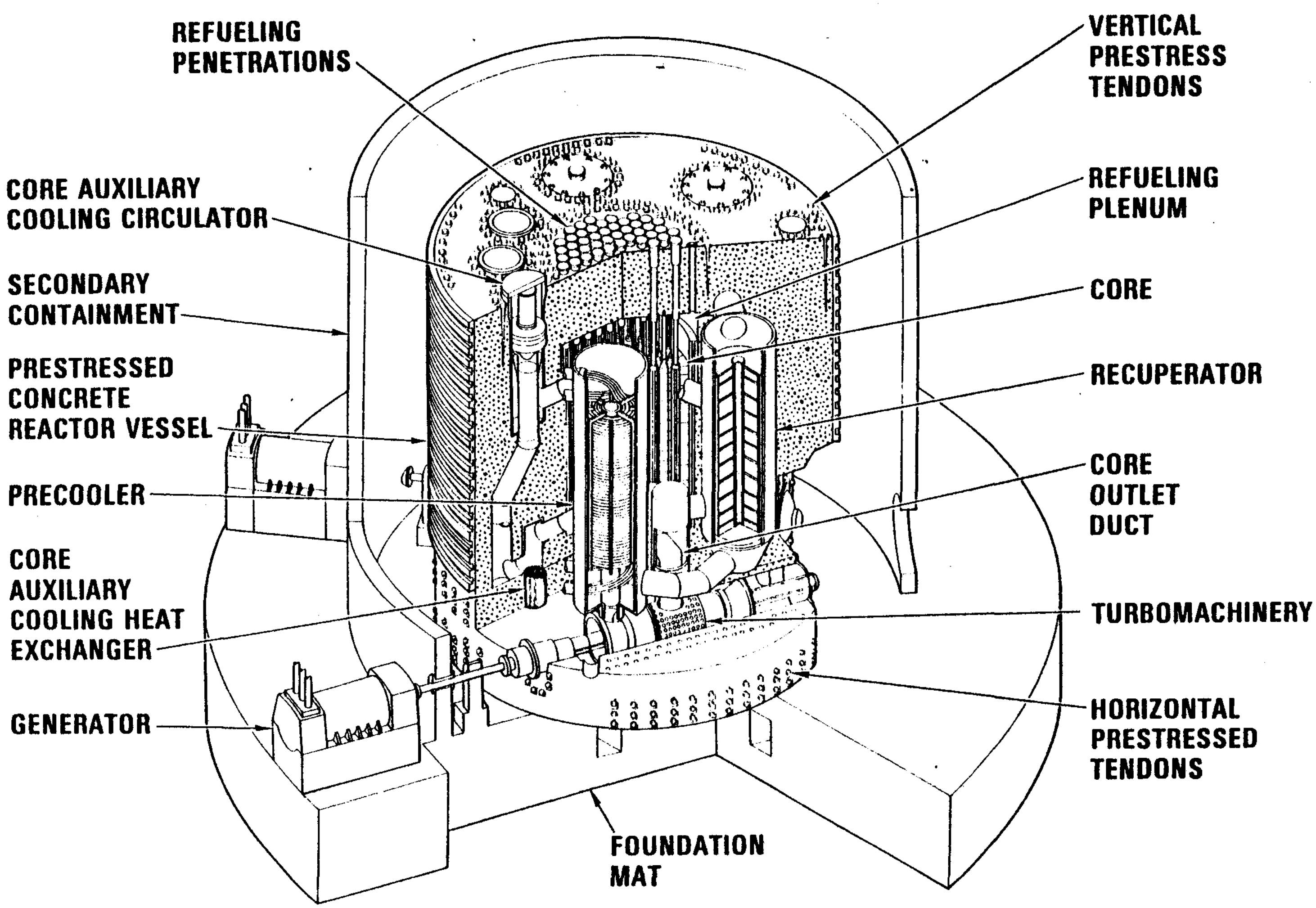
Figure 6.1-1 shows an isometric view of the HTGR-GT PCRV. The reactor core is cooled with pressurized helium, moderated and reflected with graphite, and fueled with a mixture of uranium and thorium. It is constructed of prismatic hexagonal graphite blocks with vertical holes for coolant channels, fuel rods, and control rods. Both the core and the two power conversion loops (PCL) are integrated in the multicavity PCRV. The turbomachines are located in horizontal cavities below the core cavity. The other major PCL components--the recuperator and precooler--are located in vertical cavities around the central core cavity. In addition to the PCL equipment, three core auxiliary cooling system (CACS) loops are also provided for safety-related core-cooling capability. The CACS loops, the PCL equipment, and the core are connected by a series of ducts internal to the PCRV. The internal surfaces of the PCRV cavities and ducts are lined with a steel liner and covered with a thermal barrier to limit system heat losses and at the same time maintain liner and concrete temperatures within design limits.

The 1562°F (850°C) core outlet gas energizes the gas turbomachine, which powers a 400 MWe, 60 Hz generator located outside the containment building. The HTGR-GT utilizes a recuperator to increase system efficiency and reduce heat rejection through the precooler. The precooler is a helium-to-water heat exchanger which rejects cycle waste heat to the plant cooling system, or potentially a bottoming power cycle. Depending on the particular site conditions, the cooling system may utilize all dry or a combination of dry and wet cooling towers to reject heat to the atmosphere.

The PCRV and ancillary systems are enclosed within a secondary containment building. This containment, together with the PCRV, incorporates safety features that limit the loss of primary coolant and minimizes releases in the event of failures in the turbomachinery, PCRV shaft seals, heat exchangers, or PCRV enclosures. Certain nuclear heat source (NHS) related systems, such as fuel handling and helium purification, and most

Figure 6.1-1

2 LOOP 2000 MW(t) GAS TURBINE HTGR POWER PLANT



balance-of-plant (BOP) systems and equipment are located outside the secondary containment in separate structures. Among the plant structures envisioned are the reactor service building (RSB), the controls, auxiliaries and diesel (CAD) building, the fuel storage building (FSB) with 10-year on-site storage capability, and a turbomachinery maintenance facility. Railroad access for shipping and receiving is also provided at the site.

Reactor Turbine System (RTS)

The RTS for the 2000 MWt HTGR-GT consists of those nuclear, control, heat transfer, and auxiliary systems and components necessary to operate the core and power conversion loops. These systems and components, which are unique to the HTGR-GT, are described briefly in the succeeding sections.

Prestressed Concrete Reactor Vessel and Reactor Internals - The PCRV for the HTGR-GT serves the same function and has the same base characteristics as described for the HTGR-SC in Section 5.1. However, for the HTGR-GT, the PCRV core cavity is offset from the PCRV center by 1.1 m (3 ft. 9 in.) and is surrounded by two recuperator, two precooler, and three CACS cavities. Two horizontal turbomachine cavities are located below the core cavity.

Reactor Core - The reactor core is basically the same design as described in Section 5.1. The major design difference is that the fuel blocks will have ten rows of fuel rods instead of the eight rows that are present in the HTGR-SC core. Also, the fuel will have a different design because of the higher core outlet temperatures that are required. The fissile particle will have either a uranium carbide or oxide kernel with a TRISO coating. The TRISO coating has four layers: an inner buffer layer of low-density pyrolytic carbon, a thinner layer of high-density pyrolytic carbon, a layer of silicon carbide that provides containment of gaseous and solid fission products, and an outer high density pyrolytic coating. The fertile particle has a thorium oxide kernel, also with a TRISO coating.

The present reference fuel cycle uses 20% enriched uranium (Low-Enriched Uranium)/Thorium (LEU/Th) and is currently optimized for no recycle. The ultimate goal, however, is to employ High Enriched Uranium (HEU) and Thorium fuel with full recycle. Moreover, the plant, core, and fuel designs are such that flexibility in the fuel cycle design is retained to ensure that a variety of fuel cycle schemes and uranium enrichments may be adopted in the future. Depending on the fuel cycle being applied, the conversion ratio for the HTGR may vary from .6 to .92.

Primary Coolant System - The primary coolant system includes the PCL components such as the turbomachine, recuperator, precooler, and valves required to generate power. A simplified schematic diagram exhibiting the primary cycle for the HTGR-GT is shown in Figure 6.1-2. The helium coolant flows downward through the reactor core into the core outlet plenum. The hot gas from the core outlet plenum flows radially outward through the two large ducts on opposite sides of the plenum to the turbine

DIRECT CYCLE HTGR PLANT WITH DRY COOLING

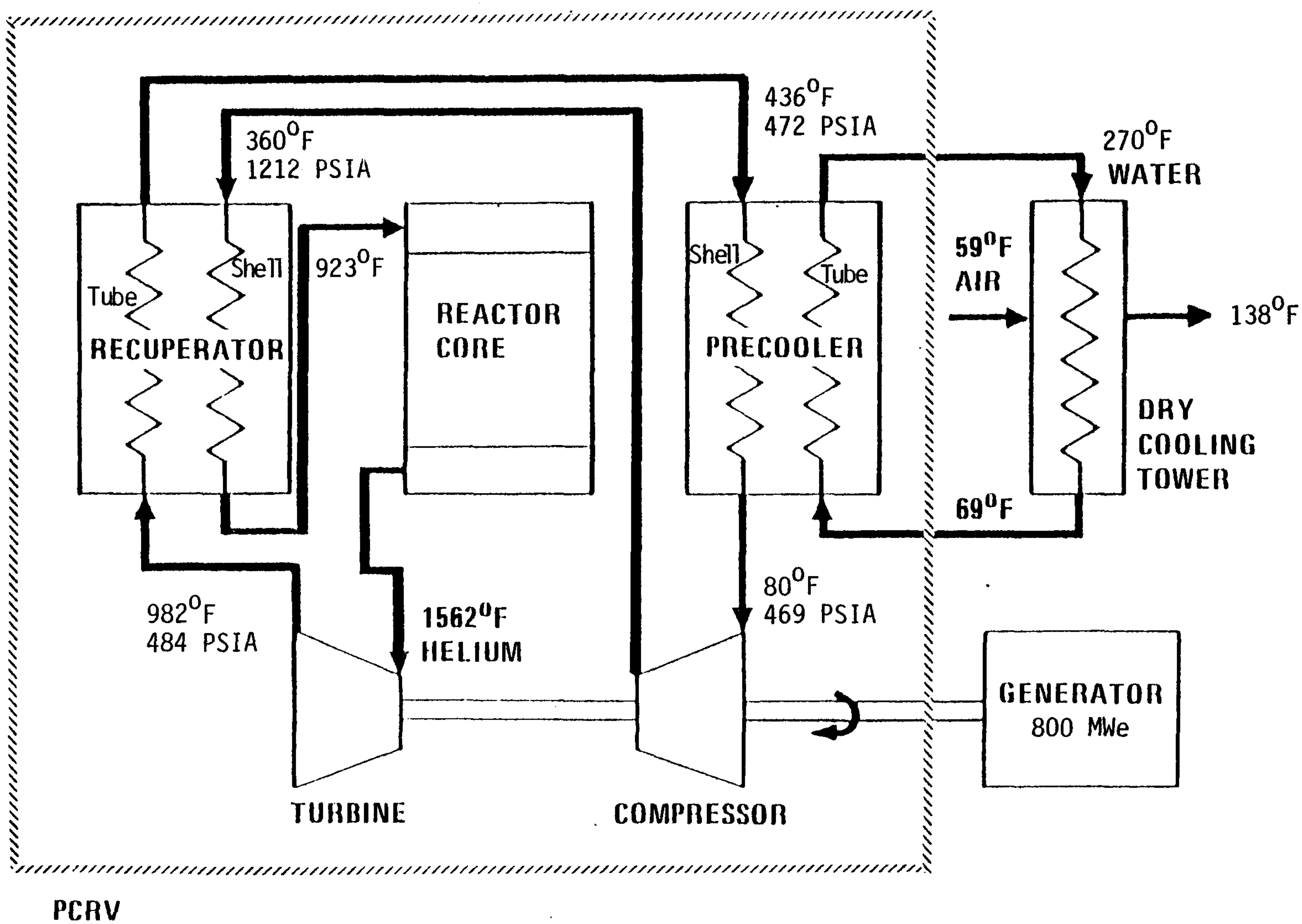


Figure 6.1-2

inlet, which is located in the center of the machine. The vertical portion of the core outlet duct is concentric with the compressor outlet duct. The gas flows through the turbine and exits into the tube side of the recuperator. It exits the recuperator tubes into the recuperator-precooler cross duct. The warm gas from the recuperator flows through this horizontal cross duct into the shell side of the water-cooled precooler, where its temperature is reduced further. The cool gas from the precooler flows downward through another short vertical duct into the turbomachine compressor inlet plenum and passes through the compressor to exit near the center of the machine. The high-pressure compressor outlet gas then flows upward through the outer concentric vertical duct to enter the inlet of the recuperator on the shell side. It flows upward through the recuperator, picking up heat from the tubes, and exits into the core inlet plenum at the top of the core cavity through radial ducts.

Helium Turbomachine - The 400 MWe helium turbomachine has 18 compressor stages, for a pressure ratio of 2.5, and 8 turbine stages. The rotor is of welded construction. The overall length of the machine is 11.3 m (37 ft.), with the 60,800-Kg (67-ton) rotor supported on two journal bearings. Rotor burst protection is incorporated in the machine design in the form of burst shields around the compressor and turbine sections. Man-access cavities are provided in the PCRV for inspection and limited maintenance work on the journal bearings, which are of the multiple, tilting-pad, oil-lubricated type. The spaces in which the bearings are located are isolated from the primary loop helium, and purged gas from the purification system is used to give an acceptable radiological environment for man access. The drive to the generator is from the compressor end of the turbomachine, with the thrust bearing located external to the PCRV to facilitate inspection and maintenance. The rotating section of the turbomachine is compact and substantially smaller than an equivalent air-breathing machine because of the high degree of pressurization, particularly at the turbine exit, and because of the high enthalpy drop in the helium turbine. The external dimensions of the 400 MWe helium gas turbine are similar to those of an air-breathing, advanced open-cycle industrial gas turbine in the 100 MWe range. The fact that the helium turbine is comparable in size to the existing machines substantiates the claim that conventional fabrication methods and facilities can be used.

Recuperator and Precooler - The recuperator in the reference plant design is of straight-tube design with the tubes welded to two forged tubesheets. In the case of the gas-to-water precooler, concern had been expressed regarding the very large number of small diameter tubes associated with a straight-tube design. Recognizing the increasing importance of maintenance and inservice inspection on heat exchanger design, a precooler embodying a helical bundle geometry with finned tubes is the reference precooler design for the HTGR-GT plant. This configuration is also much better suited for the gas-to-water heat exchanger application. The large reduction in the number of tubes associated with this flow configuration enables inspection and repair to be accomplished down to the individual tube level. Even though the single-phase working fluids (helium and water) can realize relatively high heat transfer coefficients, large surface areas are necessary because of the large heat transfer rates. However, the modest metal temperatures and internal pressure differentials, compared to modern steam generators, permit the use of code-approved, lower-grade alloys of reduced cost.

The ferritic materials selected for both exchangers have been used extensively in industrial and nuclear plant heat exchangers. Though the exchanger assemblies are large, state-of-the-art manufacturing methods can be used. The overall size and weight of both the recuperator and precooler are similar to the contemporary steam generators, and transport methods, handling, and installation techniques developed for these units will be equally applicable to the heat exchangers for the nuclear gas turbine plant.

The remaining systems of the RTS are essentially the same as those for the HTGR-SC, described in Section 5.1.

Balance of Plant (BOP)

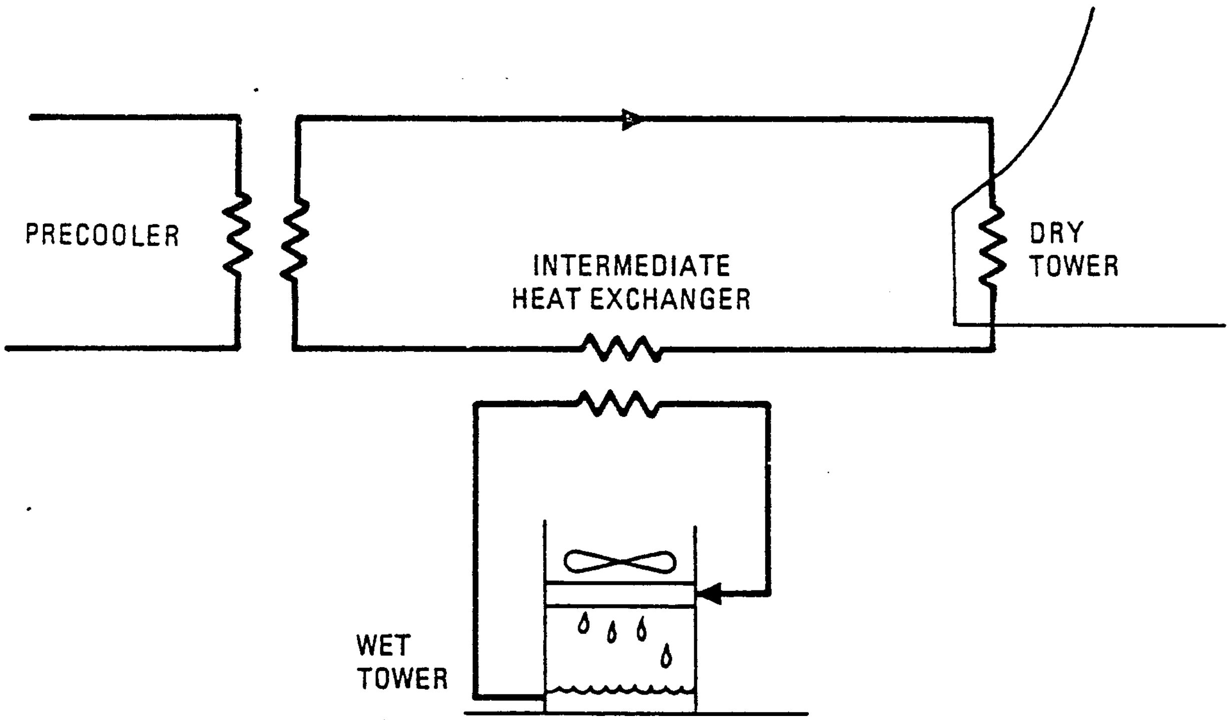
The BOP for the HTGR-GT differs from the HTGR-SC in that it requires no main steam condenser and its associated circulating water system. In addition to the usual plant electrical systems, lube oil systems, radwaste systems, etc., the HTGR-GT utilizes a totally dry or wet/dry cooling system, depending on the specific site conditions. Figure 6.1-2 shows the schematic implementation of the HTGR-GT with a dry cooling system, while Figure 6.1-3 shows a dry/wet cooling system. Wet cooling is possible for the HTGR-GT, but it does not offer any substantial financial incentive to do so. The economics of these various cooling modes are discussed in Section 6.2. Separate dry and wet towers are utilized for the dry/wet system. While several systems using combinations of dry and wet systems in the same tower may have some advantages such as eliminating visible plumes and icing, they have other problems such as louver noise, recirculation of warm, moist air, and fouling of the heat exchange surfaces. The effects of utilizing dry or dry/wet systems on HTGR-GT performance and water consumption are discussed in Section 4.2.

An assessment of the current status of the HTGR-GT design and technology is presented in Reference 39.

6.2 ECONOMIC ASSESSMENT

Table 6.2-1 presents cost data for the reference HTGR-GT plant utilizing both wet/dry cooling and an ammonia bottoming cycle (binary cycle) for heat rejection. These data are compared against similarly sized coal and LWR plants. The costs of all plants were estimated using the economic ground rules given in Table 5.2-2. The RTS cost estimate for the HTGR-GT was supplied by General Atomic Company (GAC). The HTGR-GT Binary Cycle costs were also supplied by GAC and have a higher degree of uncertainty associated with them due to the conceptual nature of the ammonia cycle components. All other estimates were performed by United Engineers & Constructors based on their experience and are applicable for the commercial equilibrium plant; therefore, they contain no first-of-a-kind costs. The cooling system adder costs were based on the analyses presented in Reference 30. The total estimated power costs present a valid comparative analysis of the plants.

Figure 6.1-3



Wet/Dry Cooling Tower System

Table 6.2-1

HTGR-GT Cost Comparisons

	HTGR-GT Dry/Wet-Cooled	HTGR-GT Binary	PWR Wet-Cooled	Coal Wet-Cooled
Plant Parameters				
Power Rating - MWt	2000	2170	2400	2200
Net Electrical Output - MWe	800	998	800	800
Efficiency	40	46	33	36
Plant Costs (x 10^6)				
Direct Costs ('80 $)	562	628	509	412
Indirect Costs ('80 $)	210	234	227	85
Total Base Costs ('80 $)	772	862	736	497
$/KWe ('80 $)	965	864	920	621
Escalation	751	839	736	562
Interest During Construction	500	559	442	212
Total Investment	2023	2260	1914	1271
$/KWe ('95 $)	2528	2264	2392	1588
Power Costs (Mills/KW-hr) ('95 $)				
Capital	74	66	70	47
O&M	14	15	14	16
Fuel LEU/Th (20%) - Once-Through	40	35	38	96
Total	128	116	122	159
Fuel HEU/Th (93%) - Recycle	29	25	30	
Total	117	106	114	
Cooling System Cost Adders*				
100% Dry Cooling	2	N/A	17	14
Dry/Wet - 115 x 10^6 gal/yr	0	N/A	11	7
Dry/Wet - 500 x 10^6 gal/yr	0	N/A	9	5
100% Wet Cooling	2	0	0	0

*Reflects cooling system capital plus operational penalties for cooling system performance at typical arid site: Modesto, California.

A discussion of the magnitude and types of development costs associated with the commercialization of the HTGR-GT is presented in Reference 39. The possible arrangements for the distribution and recovery of these development and first-of-a-kind costs are discussed in Reference 36.

Based on the information presented in Table 6.2-1, it can be seen that when compared to a wet-cooled PWR, the total power costs of the dry/wet-cooled HTGR-GT are approximately 5% higher with the once-through fuel cycle and approximately 3% higher with full recycle. These differences are within the uncertainty bandwidth of the cost estimates and, therefore, the total power costs for the HTGR-GT with wet/dry cooling can be considered equivalent to both the HTGR-SC and the LWR.

Because one of the major incentives for the HTGR-GT is its ability for relatively efficient utilization of dry cooling, and because the results of Section 4.2 and Reference 2 indicate that a substantial market for dry cooling will exist after 2000, Table 6.2-1 also provides cooling system cost adders for the HTGR-GT, LWR, and coal plants. These cost adders were calculated from the results of the UE&C cooling system study (Reference 30) and represent the added capital plus capitalized operating penalties associated with the optimized cooling systems for each plant under the various water consumption constraints imposed. When a total dry cooling requirement is imposed for a particular site, the HTGR-GT will have total power costs approximately 6% to 9% lower than the LWR and between 25% and 30% lower than the coal plant, depending on the fuel cycle.

As water becomes available for consumption at the site, the advantage of the HTGR-GT becomes smaller. For example, when 500 x 10^6 gal/yr is available, or approximately 15% of what an LWR would consume with total wet cooling, the total power costs of the HTGR-GT are only 4-6% lower than the LWR, which are within the uncertainty range of the estimates. The sensitivities of the cooling system cost adders to changes in economic assumptions are shown in Table 4.2-16.

It is also interesting to compare the dry-cooling performance of the HTGR-GT against that of the HTGR-SC. Using the cooling system cost adders for the HTGR-SC shown in Table 5.2-1 for a total dry-cooling scenario, the advantage of the HTGR-GT ranges from 3% to 6%, depending on the fuel cycle scenario. With a 500 x 10^6 gal/yr water consumption constraint, the HTGR-GT advantage is only 2-3%. This differential is well within the cost estimate uncertainty range; therefore, it appears that the HTGR-GT has limited economic advantage with dry or wet/dry cooling over the LWR and essentially none over the HTGR-SC.

Another incentive for the HTGR-GT is its ability to operate at higher efficiencies as noted in Section 4.6.2. Table 6.2-1 includes the estimate of power costs for a binary cycle HTGR-GT, i.e., one that uses an ammonia bottoming cycle for utilization of waste heat. This system has marked effects on HTGR-GT economics as the capital costs in terms of $/KWe drop by approximately $100/KWe and the total plant efficiency increases to 47%, resulting from a net plant output of 998 MWe. When compared with the dry/wet-cooled HTGR-GT, the binary version has power costs 10% lower. However, when compared to the wet-cooled HTGR-SC and the LWR, it has total power costs of only 5-7% lower, which are within the uncertainty bandwidth of the cost estimates.

The above comparisons lead to the following conclusions:

- The HTGR-GT binary cycle should be utilized instead of the dry/wet-cooled HTGR-GT where sufficient water exists for wet cooling.

- For sites where dry or dry/wet cooling is required, the HTGR-GT provides minimal economic advantage over the HTGR-SC and the LWR. If neither of the latter options were to be available, the HTGR-GT provides an economic competitor to a coal-fired steam plant.

- The binary cycle HTGR-GT provides minimal economic incentive over the HTGR-SC and LWR.

The above conclusions have been drawn from the latest available cost estimates. While it is recognized that significant uncertainty exists in the LWR cost estimates due to unresolved cost trends resulting from TMI, the uncertainty in the HTGR-GT cost estimates is considerably higher due to the conceptual nature of the present HTGR-GT designs. For this reason, the HTGR cost estimates are considered to have a higher probability of future significant cost increases.

6.3 MARKET ASSESSMENT

Based on discussions with many potential HTGR owners and users, GCRA has concluded that the only deployment route for any commercial HTGR system will be through the electric utilities. Section 2.1 of this report presented the factors which the utility industry uses to evaluate alternatives for major capital expenditures. By evaluating each of the HTGR systems relative to these factors as has been done in this Assessment, the marketability and hence the market potential of the HTGR can be determined. While this market forecast must be inherently subjective because of the various factors that are examined and weighed, it does present a complete evaluation of the HTGR from the utility/owner perspective and gives a realistic view of the potential HTGR-GT market.

Forecasted Energy Demand

Based on the results of Section 2.2.1, the projected market size for nuclear power plants between 2000 and 2020 is expected to be approximately 430 GWe. Of this 430 GWe, approximately 150-190 GWe will require dry or dry/wet cooling (Reference 2). This presents a sizable potential market for the HTGR-GT.

It is beyond the scope of this document to predict a market penetration rate for the HTGR-GT; however, because the lead plant will not be completed prior to 2003, it is doubtful that the HTGR-GT will be able to capture a significant share of the projected market prior to 2020. The status of competing technologies after 2020 cannot be predicted; therefore, the market penetration rate for the HTGR-GT after 2020 cannot be predicted at this time.

Overall, Forecasted Energy Demand is considered to be a positive market factor for the HTGR-GT.

Siting Flexibility

Sections 4.2 and 4.3 examined the aspects of the HTGR-GT which affect its siting flexibility. Of all of the HTGR systems, the HTGR-GT appears to possess the greatest advantages in this area. In addition to the radiological advantages inherent to the HTGR, the ability for relatively efficient use of conventional dry-cooling technology gives the HTGR-GT an operational advantage over the current coal and LWR technologies for siting in areas where acute water shortages will occur. For this reason, this market factor is considered to be positive for the HTGR-GT.

Technical Development Status

A detailed discussion of the technical status of the HTGR-GT is presented in Reference 39. Relative to the HTGR-SC, the HTGR-GT is several years behind in development. A large amount of work remains to be done to obtain and qualify materials which are suitable for long-term operation in the higher temperature environment of the HTGR-GT. Much work also must be done to qualify and test the turbomachinery, particularly to document the failure modes of the machine. The third area of technology advancement required over that of the HTGR-SC is in the area of fuels design. Particle coatings must be qualified for the 850°C core outlet temperatures to prevent unacceptable fission product release.

In the marketplace for the total 430 GWe of nuclear capacity between 2000 and 2020, the HTGR-GT will probably be competing against LWR technology, which will have a very large advantage in reactor years of operating experience. For the estimated 150-190 GWe of dry or dry/wet nuclear capacity to be added in 2000-2020, the HTGR-GT will have to compete against the advanced dry-cooling technologies mentioned in Section 4.2, which will also probably be available by this time period. As a result, the HTGR-GT may be competing against technologies for which water consumption constraints do not create operational or economic problems. This market factor must be considered as negative for the HTGR-GT.

Regulation and Licensing

Section 4.1 examined the licensing issues which remain to be resolved for the HTGR-GT. Based on that review, several major issues exist which could cause licensing delays in the lead plant. The costs to resolve these open licensing issues, however, cannot be estimated until a full-scale regulatory review is performed and further analyses and testing have been performed. The GCRA pre-review licensing program is designed to minimize the impact of such a review by providing continuous regulatory feedback into the design process.

Because the regulatory authorities have not had the opportunity to conduct an in-depth review of the current HTGR-GT design, design criteria and regulatory guides have not been generated which pertain to the unique aspects of the HTGR-GT. Based on the proliferation of regulations as the result of LWR operating experience, it is expected that the HTGR-GT will also cause new regulations to be written for its design and operation. The magnitude of the regulations should be considerably less than has been experienced with the LWR due to the generic nature of many of the existing regulations. Overall, after the lead plant has been constructed and operated, this market factor will have a neutral effect on the HTGR's marketability.

Commercial Status

The earliest commercial availability for the HTGR-GT is projected to be late in the first decade of the 21st century. Assuming that the present commercialization effort succeeds in building a lead plant in the 2000-2010 time frame, the industrial manufacturing base for the HTGR components will still need to be established. Table 5.3-1, which shows the manufacturing facilities that will be required to support a commercial HTGR-SC venture, is also applicable for the HTGR-GT. Limited facilities for the manufacture of the turbomachinery which presently exist will require retooling.

The commitment of the system supplier to the HTGR-GT will greatly affect the utility industry's perception of the HTGR's commercial status. The prospective owners will require contractual assurances as to the availability of field and home office technical assistance and support during the life of the plant as well as the availability of fuel and spare parts. Because the commitment and/or ability to fulfill these requirements are not readily apparent at the present time, this market factor must be considered as strongly negative.

Plant Capabilities

The operational capabilities of the HTGR-GT are still being investigated. Dynamic analyses are being performed to determine the controllability of and the interaction between the dual power conversion loops. The reactor core will exhibit the inherent characteristics of the HTGR that have been discussed previously, in particular, slow core heatup during operational transients, which is the single most important advantage of the HTGR over the LWR. Overall, while the HTGR-GT possesses the capabilities inherent to HTGR technology, the unique operational aspects of the Gas Turbine have not been fully defined and evaluated. For this reason, this is considered a neutral market factor for the HTGR-GT at this time.

Economics

The comparative economics of the HTGR-GT and the plants with which it will compete were presented in Section 6.2. Based on these latest cost estimates, it appears that the HTGR-GT has essentially cost parity with the LWR and the HTGR-SC for both the dry- and wet/dry-cooling scenarios. Further, it appears that the high efficiency binary cycle HTGR-GT essentially has cost parity with the wet-cooled LWR and HTGR-SC. In addition, the uncertainties in the HTGR-GT cost estimates are rather high due to the conceptual stages of the design and, therefore, have a high probability of becoming larger. For these reasons, Economics is considered to be a neutral market factor for the HTGR-GT with a probability of becoming negative.

Capital Risk

The events at Three Mile Island II indicate the susceptibility of the large capital investments in an LWR plant to short-term transient conditions. The inherent design of the HTGR provides protection of the investment in the plant by allowing longer operator response times to plant operational transients. While this advantage is manifested in the HTGR-SC, the ability of the HTGR-GT to provide the same degree of capital protection is not assured and has not been completely assessed. Because of economic considerations, the turbomachines have been located within the PCRV. A postulated shaft or disc failure could create high-energy missiles within the PCRV as well as cause a collapse of the pressure differentials across the turbine and compressor sections of the machine, thereby possibly causing internal PCRV damage. The risks of these types of transients are still being investigated; therefore, their consequences have not been fully quantified. For these reasons, this market factor can only be considered as neutral for the HTGR-GT at the present time.

Safety

The AIPA results presented in Section 4.1 were based on the HTGR-SC design. A complete probabilistic risk analysis has not yet been completed for the HTGR-GT. As a result of the additional accident sequences that are possible for the HTGR-GT, significant variations may occur between the AIPA results for the HTGR-GT and SC. Therefore, safety must be considered as a neutral market factor at the present time for the HTGR-GT.

Personnel Radiation Exposure

Section 4.4.2 examined the projected and the experienced HTGR-SC personnel exposure data. The major maintenance procedure which would cause the results of that analysis to differ for the HTGR-GT is the turbomachine removal, repair, and replacement. It is not possible to accurately quantify expected exposures from that activity at this time, but because of the level of fission product retention that is expected due to HTGR fuel design, this market factor is still considered to be positive for the HTGR-GT.

Fuel Cycle Flexibility

The performance of the HTGR relative to this nuclear market factor was examined in Section 4.5. While this factor is not currently a concern for utilities because of the present Administration's commitment to the once-through fuel cycle, it is expected that fuel cycle flexibility will become a major advantage to the HTGR in the early 21st century. For these reasons, this is considered a positive nuclear market factor for the HTGR-GT.

Advanced Applications

The advanced applications of the HTGR-GT serve to provide an incentive for the HTGR commercialization effort by exposing the unique markets which the HTGR may ultimately be able to serve. These advanced applications of the HTGR-GT, namely cogeneration and higher efficiencies through a bottoming cycle or higher temperatures, do provide an added incentive for government participation in the Program. It does appear, however, that more advanced technologies may satisfy these perceived future demands before the HTGR-GT can enter the market and that the economic incentive for higher HTGR-GT efficiencies may be limited. For these reasons, this market factor can only be considered as neutral at the present time.

Summary

While a sizable market is projected to exist for electricity production in the 2000-2020 time frame, a significant fraction of which will require dry or dry/wet cooling, the economic incentives for the development of the HTGR-GT to satisfy these markets do not appear to be sufficiently large at the present time to warrant the expenditure of the large sums required for commercialization of the HTGR-GT. The economic data indicate that existing LWRs can satisfy the dry cooling market and that the HTGR-SC can outperform the LWR in these markets. In areas where water availability is of no concern, the HTGR-GT binary cycle plant has projected power costs essentially equivalent to the HTGR-SC and LWR. While these conclusions are based on currently available cost estimates which have large uncertainties associated with them, the relative uncertainties of the HTGR-GT cost estimates are greater than for the LWR and coal cost estimates due to the relative immaturity of the HTGR-GT designs. It is expected that the HTGR cost estimates are susceptible to further large cost increases.

Because the economics are essentially at parity with the LWR, the HTGR-GT's technical development status will become the governing market factor in the reference time period. This factor will be viewed as negative because of the many years of operational experience that the LWR will possess which will give it a significant advantage in the dry-cooling market. Relative to the coal-fired unit, the economic advantage of the HTGR-GT can also be achieved by the HTGR-SC with much lower expenditures of development funds; therefore, the HTGR-SC becomes the HTGR-GT's chief competitor if HTGR technology achieves commercial status.

Based on the above, it is concluded that future work must produce significant cost and performance improvements in the HTGR-GT in order to justify the expenditure of the research, design, and development funding necessary to bring the HTGR-GT into the commercial marketplace.

7.0 THE HTGR REFORMER

In the Reformer application of the HTGR (HTGR-R), a portion of the reactor thermal energy is converted to a storable/transportable energy form through the use of a highly endothermic, reversible chemical reaction. The balance of the reactor thermal energy is used for base load electricity through the conventional steam cycle. It is this distinguishing feature--the capability of storing and transporting reactor energy--which offers the potential for displacement of fossil fuels, notably gas and oil, by nuclear energy in utility and industrial applications. Because peak reforming temperatures in excess of about 705°C/1300°F are required for suitable conversion efficiencies, the HTGR is uniquely capable of supplying these requirements.

Coupling the HTGR with the budding synthetic fuels technology and widespread distribution of reactor energy to intermediate and small industrial users via the "thermochemical pipeline" (TCP) concept comprise long-term objectives which might also be considered for a Lead Project if institutional circumstances permit. The concept of remote energy distribution via the TCP is described in Section 4.6.2 and later in this section. Through this concept, reactor energy can be generated at a remote location and widely distributed through a pipeline network. As it is a completely closed system, there are no releases to the environment at the point of use other than heat rejected from the process.

The HTGR-R plants envisioned for near-term applications would focus on intermediate temperature operation (approximately 850°C/1562°F reactor core outlet temperature). Lead Project variants include TCP applications for repowering of existing oil- or gas-fired power plants, distribution of energy to major industrial load centers for process steam or cogeneration, and load-following utility electric power generation through chemical storage and retrieval.

7.1 TECHNICAL DESCRIPTION

The HTGR-R demonstration plant will be powered by a 1170 MWt core in an indirect cycle configuration. The indirect cycle flow diagram is shown in Figure 7.1-1, and an isometric cut-away view of the PCRV and primary loop components is illustrated in Figure 7.1-2. As in other HTGRs, the HTGR-R has its entire primary coolant system contained in a multicavity PCRV which provides the necessary biological shielding in addition to the pressure containment function. The multicavity design allows each component (e.g., helium circulators and intermediate heat exchangers, etc.) to be located in a separate cavity, which facilitates its removal and replacement. The reactor core is cooled by helium, has ceramic-coated fuel particles containing uranium and thorium, and employs graphite as the moderator. The core and fuel design are essentially the same as for the HTGR-GT. Thermal energy is removed from the reactor core by independent primary/secondary helium systems and is supplied to separate process loops. Three CACS shutdown loops have been provided as in the HTGR systems.

The primary helium is heated by the reactor core and transfers its heat to the process plant via the secondary helium loops. Each primary loop includes one intermediate heat exchanger (IHX), an electric-motor-

Figure 7.1-1

HTGR-R Commercial Plant System Flow Diagram

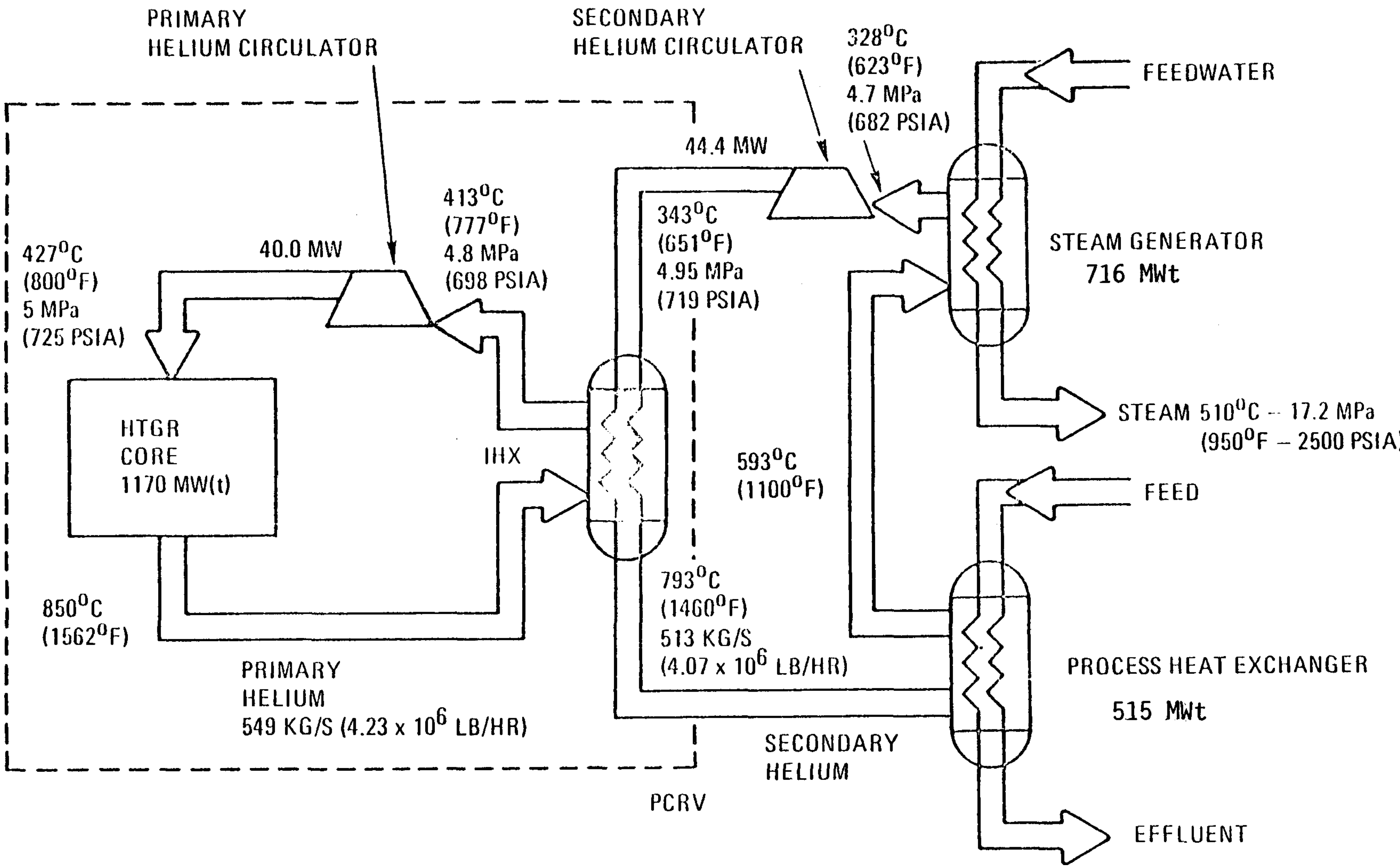
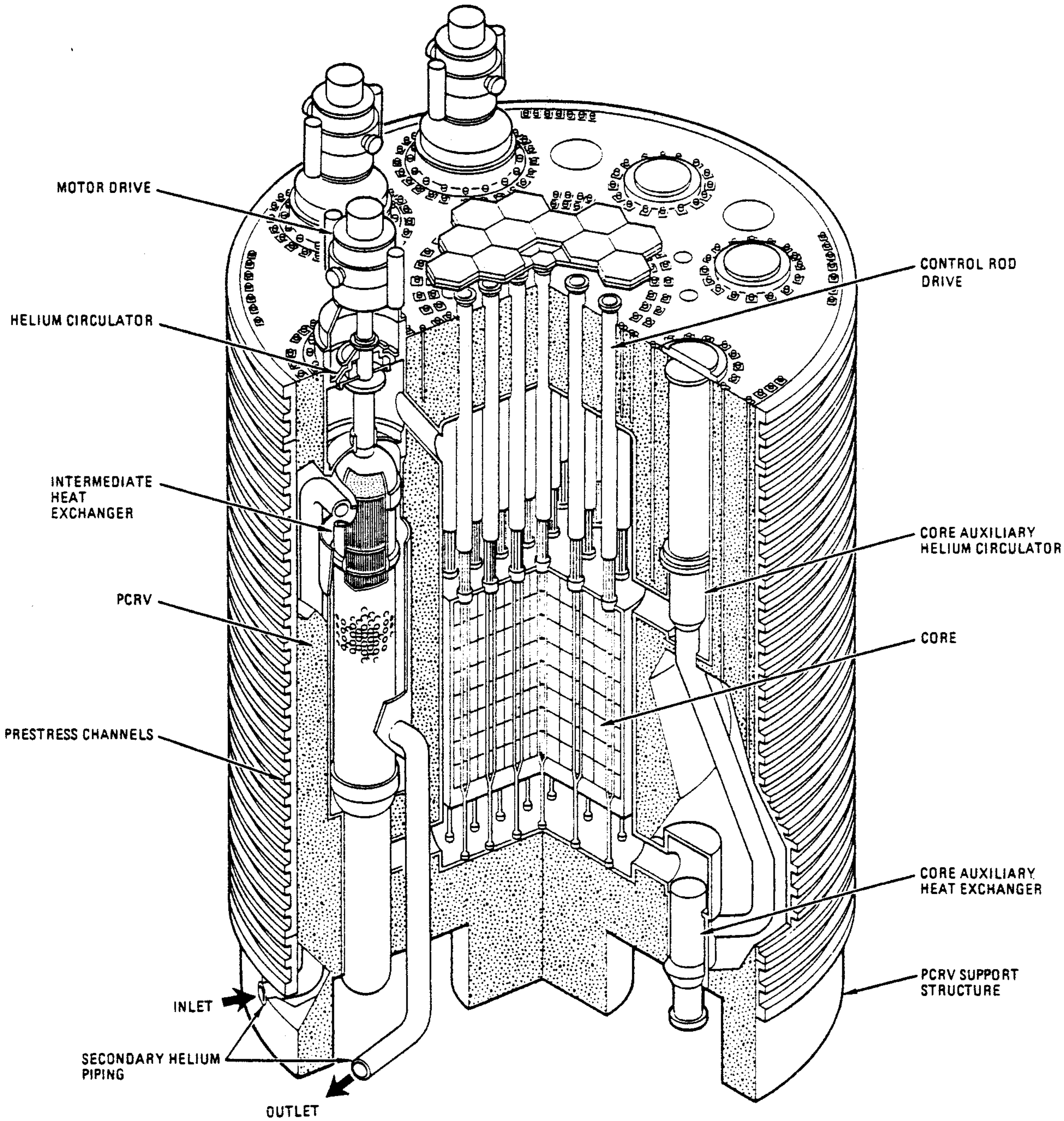


Figure 7.1-2

Isometric View of PCRV



driven primary helium circulator, and related instrumentation and controls. The primary coolant flows downward through the reactor core, where it is heated from 427°C (800°F) to 850°C (1562°F). The hot helium is collected in a plenum area beneath the core and manifolded to the IHX units situated inside cavities beside the core. The primary helium flows upward through the shell side of the IHX, counter-currently transferring heat to the secondary helium. The primary helium leaving each IHX is then delivered to its respective circulator, which returns it to the inlet plenum above the reactor core. The secondary helium loop transports thermal energy from the IHX to the process plant. The secondary helium loops each consist of a process heat exchanger (reformer), a steam generator, an electric-motor-driven secondary helium circulator, and related piping, valves, and instrumentation. Each secondary loop interfaces with its respective primary loop through the IHX. During normal operation, secondary helium is heated in the IHX and is routed outside the PCRV first to the reformer and then to the steam generator. The latter generates steam required for the process as well as additional steam for auxiliary power generation. The helium thermal energy is split between the reformer and steam generator. The secondary helium is then pumped back to the IHX by the circulator.

The HTGR-R utilizes its high temperature capability to reform a mixture of steam and methane (H_2O and CH_4) in the presence of a catalyst to form hydrogen and carbon monoxide (H_2 and CO). The heat absorbed in this endothermic reaction is supplied by the HTGR. Due to reaction characteristics, the reformer conversion efficiency is not 100%; therefore, the effluent gas consists of methane, hydrogen, carbon monoxide, and carbon dioxide (CH_4, H_2, CO, CO_2). The conversion efficiency decreases with lower reforming temperatures and increases with lower reforming gas pressures (see Figure 4.6-5). For practical conversion efficiencies, peak reforming temperatures above approximately 705°C/1300°F are required. The steam generator provides steam for both electrical power generation and process plant energy needs.

The products of the reforming process can be used in a variety of applications as previously described. For the Lead Project, however, initial emphasis will be placed upon energy storage/transmission and subsequent recovery of reactor heat via methanation. Further, either on-site or off-site methanation alternatives are being considered as described below.

- Off-Site Methanation - The reformer effluent gases are cooled by counter-current heat exchange with the reformer inlet gases. Any excess steam is condensed and the effluent gases are compressed for transmission through a pipeline to the user site. At the user site, the hydrogen and carbon monoxide are heated then combine in the presence of a catalyst in an exothermic reaction. The high-grade heat released in a methanator (at $\geq$ 600°C/1100°F) can deliver up to 540°C/1000°F steam at the user site. The methanator effluent of methane and water is cooled in a recuperative heat exchanger, preheating the inlet gases. The methane and water are then transmitted back to the reformer via two pipelines, completing the cycle. The pipeline itself may serve as a gas storage mechanism for short time periods, or gas storage facilities may be provided if longer durations of peak load operation are desired. Off-site methanation may be utilized for remote industrial process heat and cogeneration or for repowering of existing oil- and gas-fired electrical power plants.

- On-Site Methanation - This application is very similar to the off-site case except that synthesis gas storage and methanators are provided on site. The reformer effluent gases are pressurized and stored at ambient temperatures at or near the plant site. As dictated by the utility load requirements, the gas is pumped to a methanator where heat can be transferred to any medium including water/steam. Up to 540°C/1000°F steam can be generated for off-site transmission or for supplemental on-site usage. This supplemental on-site steam generation may be utilized to produce additional electrical output for load-following during intermediate and peak demand periods, in effect the chemical equivalent of a pumped storage system.

In the above applications, the nuclear heat source is base-loaded while the thermochemical transmission/storage system is load-following. EPRI has noted (Reference 28) that energy storage permits the displacement of expensive conventional peaking and load-following capacity by increasing the loading of baseload units. Because of large variations in many utilities' system daily load profile, a portion of baseload capacity is often unused during off-peak periods. Full 24-hour utilization via load-following through energy storage should improve the relative economics of capital-intensive, baseload power plants. This assumption was confirmed by the results of the utility systems analysis performed in Section 3. Preliminary economic evaluation of the electricity load-following configuration, however, shows that significant performance improvement is required to make it competitive with the anticipated competition of the LWR with battery energy storage and present load-following technologies.

The above concepts employ a closed-loop system in which the methanator effluent--water and methane--is returned to the HTGR plant site to once again be reformed to hydrogen and carbon monoxide. The HTGR-R may also be employed in an open system whenever adequate methane and water supplies are available at the plant site. A good example would be coupling with a coal gasification application where the methane produced from the coal could be utilized via reforming to transfer reactor heat to a remote load center where, following methanation to recover the reactor heat, the methane could be distributed via conventional means for residential and industrial use. In addition, the syngas (hydrogen and carbon monoxide) produced from reforming coal-derived methane has a wide variety of industrial uses, including production of liquid motor fuel by indirect coal liquefaction.

For applications after the Lead Project, direct utilization of the reformer product gas can be accomplished by the coupling of the HTGR-R with a synfuels facility. The hydrogen, electricity, and steam produced by the HTGR-R can be directly utilized in such a facility to increase the overall process efficiency and product yield. In this configuration, no methanation equipment is required and only relatively short lengths of transmission pipeline. This eliminates a significant capital cost portion of the HTGR-R configuration examined in Section 7.2, but the economics of this type of arrangement remain to be examined.

An assessment of the current status of the HTGR-R design and technology is presented in Reference 38.

7.2 ECONOMIC ASSESSMENT

A preliminary economic assessment was performed for an off-site methanation configuration of the HTGR-R for remote energy delivery with 44% of reactor power used for baseload electricity production. The configuration assumed a 100-mile thermochemical pipeline, solution mined salt cavern storage at the customers' sites, and twenty-six 56-MWt methanator trains at the customers' installations. The economic assumptions and parameters are given in Table 5.2-2.

Table 7.2-1 shows the breakdown of the plant capital costs for the assumed configuration of the HTGR-R. Table 7.2-2 shows the levelized annual energy costs in current 1995 dollars. The extremely high product costs that are produced from the studied configuration are the results of several factors:

- Design immaturity
- Higher than anticipated capital costs
- Lower than anticipated net energy output

These factors are partially a result of the scheduling requirements for the Lead Project evaluation, which left no time for design optimization. The result is a product cost which is noncompetitive. For example, a fluidized bed combustor will produce steam at a cost of $59/MBTU in 1995, assuming a present-day cost of coal of $1.80/MBTU and a one-shift operation capacity factor for the FBC.

At this time, definite conclusions cannot be drawn concerning the economics of the HTGR-R. It is clear, however, that significant design, performance, and cost improvements are required to make the HTGR-R competitive with other potential process energy supply technologies.

7.3 MARKET ASSESSMENT

Based on discussions with many potential HTGR owners and users, GCRA has concluded that the only deployment route for any commercial HTGR system will be through the electric utilities. Section 2.1 of this report presented the factors which the utility industry uses to evaluate alternatives for major capital expenditures. By evaluating each of the HTGR systems relative to these factors, the marketability and hence the market potential of the HTGR can be determined. While this market forecast must be inherently subjective because of the various factors that are examined and weighed, it does present a complete evaluation of the HTGR from the utility/owner perspective and gives a realistic view of the potential HTGR-R market.

In this section, the utilization of the HTGR-R will be evaluated for both on-site and off-site methanation. The on-site methanation configura-

Table 7.2-1

1170 MWt HTGR-R

Plant Capital Costs (1/80 $) x 10^6

Base Plant		
Structures and Improvements	124	
Reactor Plant Equipment	246 (1)	
Turbine Plant Equipment	48	
Electric Plant Equipment	59	
Miscellaneous Plant Equipment	14	
Main Condenser Heat Rejection System	6	
Secondary Helium System	46	
Reforming Plant Equipment	157	
Directs	700	
Indirects	280	
Contingency	54	
Subtotal		1034
Pipeline and Storage		
Base	90	
Indirects	47	
Contingency	--	
Subtotal		137
Methanation Plant		
Base	333	
Indirects	158	
Contingency and Fee	131	
Subtotal		622
Total Plant Base Construction Cost		1793

(1) Does not include replacement IHXs.

Table 7.2-2

HTGR-R Energy Costs

<u>PLANT COSTS ($x10^6$)</u>	
TOTAL BASE COST + CONTINGENCY	1793
ESCALATION	1867
INTEREST DURING CONSTRUCTION	1033
TOTAL INVESTMENT	4663
<u>ANNUAL LEVELIZED COSTS (1995 \$) ($x10^6$)</u>	
CAPITAL	839
O&M	90
FUEL LEU/Th (20%) - ONCE-THROUGH	118
CASE 1-TOTAL	1047
FUEL HEU/Th (93%) - RECYCLE	88
CASE 2-TOTAL	1017
<u>PRODUCTS</u>	
BASE LOAD ELECTRIC 24 HRS/DAY (MWe) (70% CF)	34
THERMAL ENERGY 8 HRS/DAY (MWt)	1464
<u>ANNUAL LEVELIZED PRODUCT COSTS (1995 \$)</u>	
ELECTRICITY	123 MILLS/KW-HR
STEAM	\$97/MBTU

tion will be evaluated for use as a utility load-follower where the supplemental on-site steam generation is utilized to produce additional electrical output for load-following during intermediate and peak load periods. The off-site methanation configuration will be evaluated for use as an industrial process heat distribution system with the thermochemical pipeline (TCP). Delineations will be made between the off- and on-site methanation systems during the discussion of each market factor as appropriate.

Forecasted Energy Demand

Section 2.2.1 forecasted a total installed capacity of 2034 GWe by 2020. It also predicted that during the twenty-year period of 2000-2020, 1022 GWe of utility capacity would be added. Typically, the percentage of installed capacity which is dedicated as peaking capacity is approximately 5% to 15%. The percentage of intermediate capacity is not easily identifiable as it may also be used for base load, but it can be considered to be typically 20% to 40% of total installed capacity. Therefore, when intermediate and peaking capacities are taken together, they represent between 25% and 50% of total installed capacity, which translates to a potential market share of the above 1022 GWe of between 250 and 500 GWe. This present 25% to 50% market share is likely to be reduced prior to 2000 with the introduction of energy storage systems, the expansion of industrial cogeneration, and increased conservation. As a result, the need for peaking power capacity is expected to be reduced. The results of the Section 3 analyses indicate that the intermediate and peaking capacities market share could be reduced to approximately 15% to 20% with the introduction of energy storage, which could capture an 8% to 12% market share by 2020. Figures 3.3-9 and 3.3-12 graphically show these trends.

What the above discussion shows is that there will exist a substantial market for energy storage technologies which can store the relatively inexpensive power of nuclear baseload capacity for use during times of peak utility system load and thereby reduce the need for relatively expensive-to-operate peaking capacity. Therefore, forecasted energy demand is considered as a positive market factor for the reference on-site methanation configuration.

Section 5.3.2 examined the market for the HTGR-PS/C. In the discussion of the forecasted energy demand, two basic conclusions were reached, i.e., that a large market will exist for industrial process steam in the time frame of this study and that in order to allow economic generation and delivery of energy to this market, an energy storage system must be utilized. Both of these conclusions are also directly applicable to the off-site methanation configuration of the HTGR-R and result in a positive market factor for the HTGR-R.

Siting Flexibility

As has been shown previously in this report, the HTGR has the potential for increased siting flexibility over other nuclear systems because of its radiological and water utilization characteristics. The major competitor of the HTGR-R, however, is most likely to be coal-fired fluidized bed combustors (FBC). This comparative basis may serve to nullify the radiological advantages of the HTGR and, in fact, may act to its detriment because of the reduced siting regulations for fossil-fired facilities relative to nuclear. These regulations generally result in more difficult as well as more remote siting for the nuclear unit. Present Environmental Protection Agency regulations may also provide impediments to coal siting as the limitations on emissions for each air quality district are determined. These will serve to limit conventional coal plant siting. Their effect on the FBC cannot yet be determined but should be reduced because of the FBC's lower emissions.

The HTGR-R also presents a unique siting problem in that the reforming gases are both toxic and explosive and must be stored at a safe distance from the nuclear containment structure. The synthesis gas storage field would be required to be approximately 1.2 miles from the reactor containment, and the methane storage field would have to be approximately 1.1 miles away (Reference 38).

Present economic studies indicate that in order to store the synthesis gas and methane economically, underground storage caverns must be used in lieu of surface storage tanks. It is anticipated that either salt deposits can be used with solution mining or that hard rock formations can be excavated using conventional mining techniques. Excavation of hard rock sites is from six to nine times as expensive as solution salt mining; therefore, salt is the preferred storage medium. Also, the storage medium must have sufficient thickness, low porosity, satisfactory caprock properties, and virtually no faults or fractures which communicate with other strata. Two separate caverns would be required, one each for the returned methane and the reformed synthesis gas. For the on-site methanation configuration, 1.3×10^7 ft^3 of storage is required for the synthesis gas while 4.1×10^6 ft^3 is required for the methane. For the off-site methanation configuration with on-site storage, 2×10^7 ft^3 of storage is required for synthesis gas and 5.3×10^6 ft^3 for methane.

The water generated in the methanation reaction must also be stored on site in tanks. Depending on the configuration, the size of this storage capacity must be between 8.8×10^5 and 2.7×10^6 gal. As for the water consumed by this facility, once the initial storage requirement is filled, the heat rejection system will exhibit characteristics similar to the HTGR-SC.

Based on the above analysis, when compared to its anticipated competition, i.e., the FBC, the siting flexibility of the HTGR-R is considered to be neutral at the present time due to the many institutional uncertainties that exist.

Technical Development Status

A detailed discussion of the technical status of the HTGR-R is presented in Reference 38. Relative to the HTGR-SC and PS/C, the HTGR-R is several years behind in development. A large amount of work remains to be done to obtain and qualify materials which are suitable for long-term operation in the higher temperature environment of the HTGR-R (850°C core outlet temperature). Particularly, the materials presently being considered for the reformer and the intermediate heat exchanger (IHX) must be code qualified for temperatures up to 1600°F (871°C). Alloy 800H, which is under consideration, is presently only qualified to 1400°F (760°C).

In addition to the materials development that is required for the reformer, work must also be performed in the areas of thermochemical performance, hydraulic performance, and alternative configurations. The first two of these areas relate to obtaining engineering data to verify the adequacy of the design, whereas the third area relates to investigating improved designs to significantly reduce capital and maintenance costs.

Another area of technology advancement required over that of the HTGR-SC is in the area of fuels design. Particle coatings must be qualified for the 850°C core outlet temperatures to prevent unacceptable fission product release.

The expected total research and development costs to bring the HTGR-R to lead plant status are presented in Reference 38. To meet the 1995 startup date for the lead plant, a relatively high technical risk schedule must be followed. This can be compared to the status of the FBC, which currently has prototype units in operation and is expected to be available for commercial orders by 1986 and will have several hundreds of unit-years of operating experience by the time of commercial availability of the HTGR-R. For these reasons, the technical development status of the HTGR-R is considered to be a negative market factor.

Regulation and Licensing

Section 4.1 briefly examined some of the licensing issues which remain to be resolved for the HTGR-R. Additional issues which must be resolved include the allowable safe distances from the reactor containment to the synthesis gas storage cavern for protection from detonation pressure waves, the design of systems for control of the toxicity of the carbon monoxide produced by the reforming reaction and methods of limiting carbon monoxide leakage, and the leakage of tritium from the primary coolant by diffusion through materials and connections into the heat pipe with resultant transportation off-site. The latter is of particular concern with the off-site methanation configuration but is not expected to become a major licensing issue due to the use of an intermediate helium loop. The costs to resolve these and the other licensing issues cannot be estimated until a full-scale regulatory review is performed and further analyses have been completed. Based on the above, it appears that several major issues exist which could cause licensing delays not only in the lead plant but also in the follow-on commercial plants because of the gas storage issues that will have to be reviewed on a site-specific basis. Based on these licensing concerns and the potential magnitude of their costs of resolution, this market factor could be considered to be negative for the HTGR-R, but because of the large institutional uncertainties that will not be resolved for some time, this factor is evaluated as neutral at the present time.

Commercial Status

The earliest commercial availability for the HTGR-R is projected to be in the first decade of the 21st century. Two potential suppliers have expressed interest in the HTGR-R concept; however, neither has committed any significant amounts of private funds toward the development of the HTGR-R. The commitment of the system supplier to the HTGR-R will greatly affect the utility industry's perception of its commercial status. The corporate positions of General Atomic Company and the General Electric Company on the HTGR-R are presented in Appendix B. The prospective owners will require contractual assurances as to the availability of field and home office technical assistance and support during the life of the plant as well as the availability of fuel and spare parts. Because the commitment and/or ability to fulfill these requirements are not readily apparent at the present time, this market factor must be considered to be negative.

Plant Capabilities

The on-site methanation configuration of the HTGR-R is unique among central station generating units in that it is able to store a portion of the reactor output energy in thermochemical form for later utilization during times of peak system demand. Section 3 of this Assessment demonstrated the positive effects that energy storage has on utility system operation and economics. Therefore, the capability of the HTGR-R to perform as a baseload and energy storage plant is a positive market factor.

For the off-site methanation configuration, the use of the thermochemical heat pipe (TCP) for transportation of the reactor energy allows transmission over long distances relative to steam transmission distances. This capability satisfies the question of distance between the nuclear heat source and the customer that arises with the HTGR-PS/C. The inherent energy storage capability of the TCP also satisfies the concern with the HTGR-PS/C of meeting the load profile of the customers while maintaining a high heat source capacity factor. For these reasons, the capabilities of the HTGR-R with off-site methanation are also considered to yield a positive market factor.

Economics

Based on the limited economic evaluations performed to date, the economics of the HTGR-R appear to be non-competitive. These results were based on a configuration which has not been optimized and requires extensive future study and design. As a result, definite conclusions on the economic competitiveness of the HTGR-R cannot be made at this time; therefore, economics is presently considered to be a neutral market factor for the HTGR-R.

Nuclear Specific Market Factors

While the HTGR-SC and GT utilize the nuclear market factors to their advantage against competing LWR systems, the HTGR-R with off-site methanation must compete against a fossil system which does not require evaluation against these factors. As a result, they can be considered to be neutral or negative depending on the potential market's perception of the nuclear-related characteristics of the HTGR-R relative to its fossil competition.

For the on-site methanation configurations where the competition is anticipated to be either coal or the LWR plus batteries for energy storage, these market factors can also be either neutral or negative. Relative to the LWR, the capital risk, safety, and personnel radiation exposure of the HTGR-R cannot yet be quantified, but the inherent HTGR advantages in these areas may be outweighed by the issues of the explosiveness and toxicity of the reforming gases, thereby making the nuclear-related issues only of secondary importance.

Institutional Factors

Because of the uniqueness of the HTGR-R as a nuclear heat source which can transmit thermochemical energy to customers over relatively long distances, several institutional factors will play a major role in the determination of the viability of the HTGR-R concept with the off-site methanation configuration. The potential market is composed of electric utilities which would generate and transmit energy via the thermochemical pipeline to industrial customers. The emerging trend which is currently being encouraged in several states, however, is for industrial plants to generate steam for in-plant processes and to cogenerate the electricity to be utilized within the plant or to sell it to the serving utility. This is representative of the trend toward smaller, decentralized systems for process heat generation. This trend is not conducive to the introduction of large central station energy distribution systems.

Several other major institutional factors must also be considered when assessing the potential market for the HTGR-R. They include:

Reliability Requirements - A reliability level for steam flow of 98-99% is required for major users of industrial steam (Reference 35). A premium has been put on this high reliability requirement by providing considerable on-line excess capacity. Loss-of-production rates of 1.9% were experienced in the survey due to planned and unplanned outages. Nuclear system outage rates would necessarily be much higher. As a result, additional excess capacity would be needed for each customer to provide the required reliability of supply. This excess capacity can be provided either through other central station facilities, which would be uneconomic for a small distribution system, or with small local oil- or gas-fired units which are less capital-intensive and, therefore, more economic when utilized as a backup supply.

Contractual Arrangements - Under utility ownership, the HTGR-R will produce thermochemical energy for sale to customers at a rate which will allow the utility to obtain the regulated rate of return on its investment in the plant and the distribution pipelines. Because of the large capital expenditures involved, customer commitments would have to be obtained before a utility would be willing to commit to construction of such a facility. These commitments would have to be such so as to assure sufficient return to the utility and its investors. When this requirement is viewed in the light that the lead time for any nuclear plant is at least 10 years, it follows that potential customers would need to make contractual commitments 10 to 15 years in advance of their service date, which is not compatible with current industrial planning horizons. In addition, the reliability requirements of the customer and the resultant excess installed capacity must be accounted for in the contractual arrangements between the utility and the customer.

The implications of the above are that the formulation of suitable financial arrangements between the utility and the customer offers substantial obstacles to be overcome before implementation of this type of system can take place.

Summary

As is the case with the HTGR-PS/C, the concept of a nuclear unit supplying a process energy distribution network provides several unique and formidable barriers to the commercialization of the HTGR-R. These barriers include the institutional problems mentioned above as well as the licensing and siting restrictions that may result from the generation and storage of the synthesis gas and methane. However, a sizable market is expected to exist after 2000 for process energy. If an economic incentive is shown to exist for the HTGR-R, this projected demand for economic industrial process energy may create a situation which will force timely resolution of the technical, commercial, and institutional problems.

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APPENDIX A

UTILITY SYSTEMS ANALYSIS
DATA BASE AND ASSUMPTIONS

Table A.1-1

Major Characteristics of EPRI Synthetic Utility Systems (1) (1985)

	Synthetic System					
	A	B	C	D	E	F
Applicable Regional Systems	Northeast Southeast East Central	West	West Central	Northeast	South Central	Northeast Southeast
Peak Load - MW	44,000	38,000	16,500	26,000	37,000	26,000
Generating Capacity - MW	53,500	46,000	22,000	32,000	45,500	31,800
Generation Mix - %						
Steam - Coal	60	20	50	35	25	10
Oil	8	23	15	25	5	45
Gas	-	-	-	-	50	-
Nuclear	21	10	20	25	15	30
Combustion Turbine	8	5	5	15	5	5
Combined Cycle	-	2	-	-	-	-
Conventional Hydro	1	38	7	-	-	5
Pump Storage Hydro	2	2	3	-	-	5
Installed Reserve - %	21.6	21.1	33.3	23.1	23.0	22.3
Annual Load Factor - %	59	69	57	59	56	63
Time of Annual Peak	Summer	Winter	Summer	Summer	Summer	Summer

Notes: (1) From EPRI Technical Assessment Guide, EPRI PS-866-SR, June 1978.

Table A.1-2

Major Characteristics of
Regional Utility System (1)
(1985)

	Regional System Northeast
Regional Reliability Council(s)	MAAC, NPCC
Summer Peak Load - MW	88,094
Generating Capacity - MW	113,357
Generation Mix - %	
Steam - Coal	18.5
Oil	35.1
Gas	-
Nuclear	24.6
Combustion Turbine	11.6
Combined Cycle	0.8
Conventional Hydro	5.7
Pump Storage Hydro	3.5
Other	0.1
Installed Reserve - %	28.7
Annual Load Factor - %	62.1
Time of Annual Peak	Summer

Notes: (1) Based on the NERC 8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems, August 1978.

Table A.1-3

Example of Levelized Annual Fixed Charge Rate Calculation

Total Return (Weighted Cost of Capital)	10.00%
Book Depreciation (Sinking Fund)	.61
Allowance for Retirement Dispersion (Iowa Type S1)	56
Levelized Annual Income Tax	4.70
Property Taxes, Insurance, etc.	2.00
Total, w/o Income Tax Preference Allowances	17.87%
Levelized Annual Accelerated Depreciation Factor	(2.47)
Levelized Annual Investment Tax Credit at 4%	(0.77)
Total, w/Income Tax Preference Allowances	14.63%

Source: EPRI Technical Assessment Guide, PS-866-SR, June 1978.

Based on a 30-year book life and a 20-year tax life and using flow-through accounting.

A.1 GENERATING UNIT PERFORMANCE DATA

A. Heat Rates

For existing base system steam units, the full load heat rates were based on the EPRI-prepared data bases for the selected synthetic systems. The minimum load generation levels and heat rates are based on Reference 20 data, as a percentage of full load generation and heat rate. The coal unit heat rates were regionalized. For base system gas turbine (GT) and combined cycle (CC) units, the heat rates were also based on Reference 20 data.

For candidate expansion units similar to existing unit types, the heat rates were based on the comparable base system units. The conventional coal unit heat rates include the effect of FGD systems. For advanced technology expansion system thermal units, the heat rates were based on Reference 22 data. The AFB unit heat rates were regionalized, and for advanced batteries, the cycle efficiency and storage capacity values were based on data received from Public Service Electric & Gas (PSE&G).

B. Outage Rates

For existing base system units, the outage rates were based on Reference 20 data. For candidate expansion units similar to existing unit types, the outage rates were based on the comparable base system units. The conventional coal unit outage rates include the effect of flue gas desulfurization (FGD) systems. The atmospheric fluidized-bed (AFB) outage rates were based on the EPRI Technical Assessment Guide, PS-866-SR, June 1978 (TAG), as revised in March 1979, and the advanced battery outage rates were based on PSE&G data.

Base and expansion candidate generating units' heat rates and outage rates are shown in Tables A.1-4A and 4B.

Table A.1-4A

BASE SYSTEM GENERATING UNIT
HEAT RATES AND OUTAGE RATES

Unit Type	Size (MW)	Minimum Load (% Full Load)	Heat Rates at Full and Minimum Loads (Btu/KWHr) Full	Minimum	Equivalent Forced Outage Rate (%)	Planned Maintenance (%)	Availability (%)
Nuclear	All	75	10,100	10,140	15.0	13.4	73.6
Coal	200	25	10,085	12,300	7.4	9.9	83.4
	400	25	9,555	11,360	13.0	12.3	76.3
	600	25	9,450	11,490	21.0	12.3	69.3
	800	40	9,290	10,220	24.0	13.4	65.8
Oil	200	25	9,795	11,960	7.4	9.9	83.4
	400	25	9,300	11,050	13.0	12.3	76.3
	600	25	9,200	11,180	21.0	12.3	69.3
	800	40	9,000	9,900	24.0	13.4	65.8
Gas Turbine							
Pre '75	50	100	15,000	--	24.0	4.9	72.3
Post '75	50	100	11,500	--	24.0	4.9	72.3
Combined Cycle	400	33	8,400	9,000	26.0	7.5	68.5
Conventional Hydro	All				1.2	3.6	95.2
Pumped Hydro	200	67% cycle efficiency, 10 hr. storage			5.0	9.3	86.2

Table A.1-4B

EXPANSION CANDIDATE GENERATING UNIT
HEAT RATES AND OUTAGE RATES

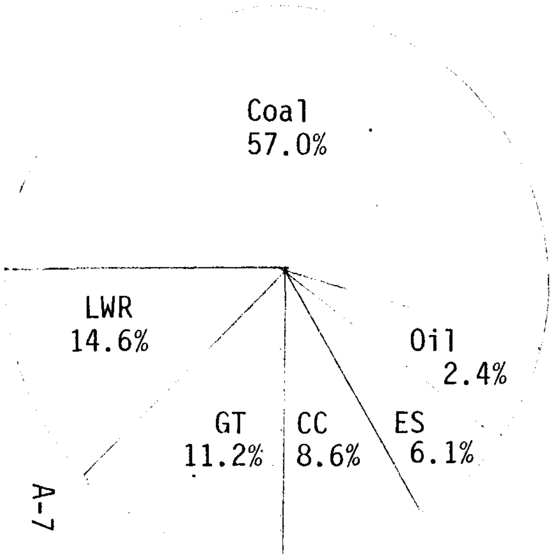
Unit Type	When Available	Size (MW)	Minimum Load (% Full Load)	Heat Rates at Full and Minimum Loads (Btu/KWHr) Full	Minimum	Equivalent Forced Outage Rate (%)	Planned Maintenance (%)	Availability (%)
Nuclear								
LWR	1985	1200	75	10,100	10,140	15.0	13.4	73.6
HTGR	2000	1200	25	8,616	9,073	15.0	13.4	73.6
Coal								
Conventional	1985	1000	40	9,635	10,600	26.0	13.4	64.1
w/FGD		600	25	9,910	11,770	22.5	12.3	68.0
Atmospheric Fluidized-Bed (AFB)	1990	1000	50	9,870	10,460	12.4	10.0	78.8
Gas Turbine								
Conventional	1985	75	100	11,500	--	24.0	4.9	72.3
Advanced	1987	100	100	9,500	--	24.0	4.9	72.3
Combined Cycle								
Conventional	1985	250	33	8,400	9,000	25.5	7.5	68.9
Advanced	1989	285	33	7,500	8,040	25.5	7.5	68.9
Advanced Batteries	1990	50	75% cycle efficiency, 5 hr. storage			4.0	2.0	94.0

Figure A.1-5

Year 2020 System Characteristics

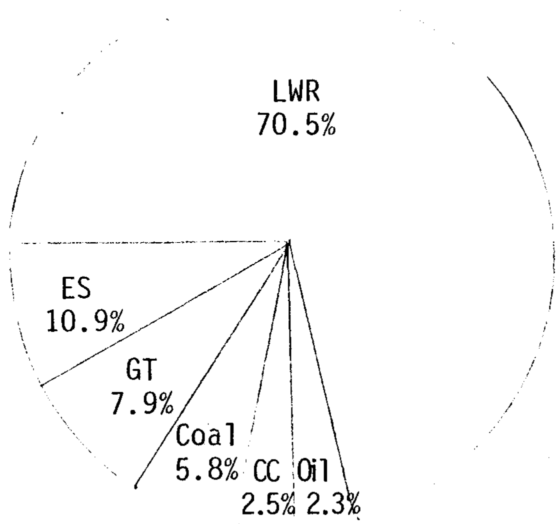
Coal Base Case

Installed Capacity (%)



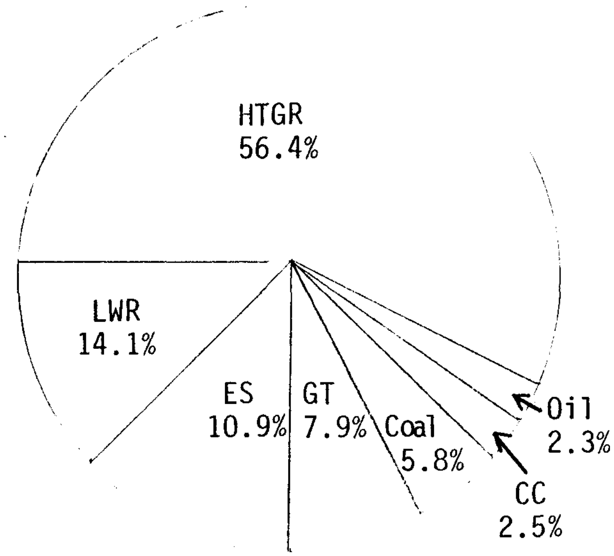
LWR Base Case

Installed Capacity (%)



HTGR Base Case

Installed Capacity (%)



Generation Type	Coal Base Case System Megawatts	LWR Base Case System Megawatts	HTGR Base Case System Megawatts
LWR	4800	24000	4800
HTGR	0	0	19200
Coal			
1000	1000	1000	1000
AFB	17800	1000	1000
Subtotal	18800	2000	2000
Oil	800	800	800
Gas Turbine	3700	2700	2700
Combined Cycle	2850	855	855
Energy Storage	2000	3700	3700
Total	32950	34055	34055

Figure A.1-6

Year 2020 System Busbar Costs

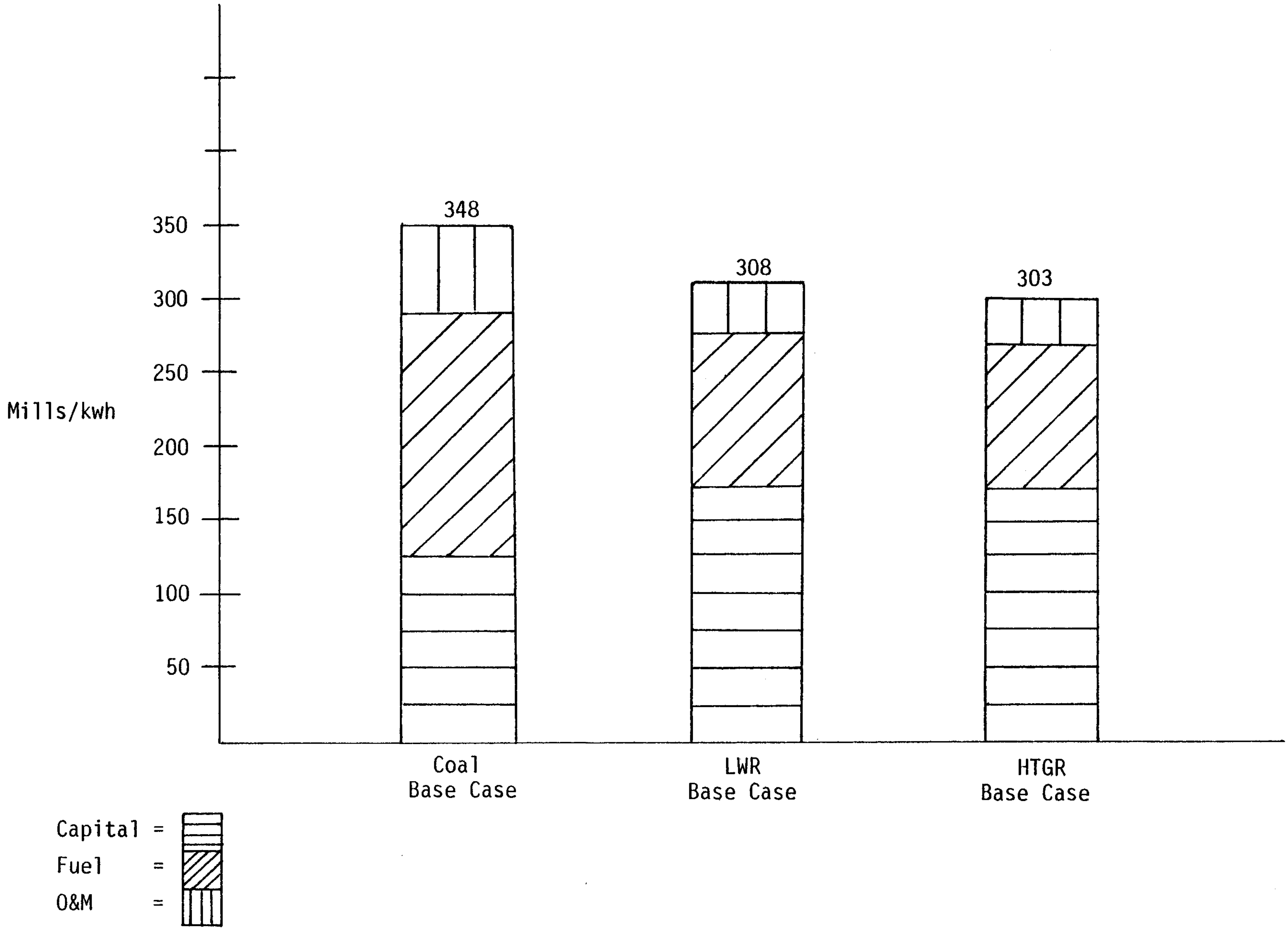
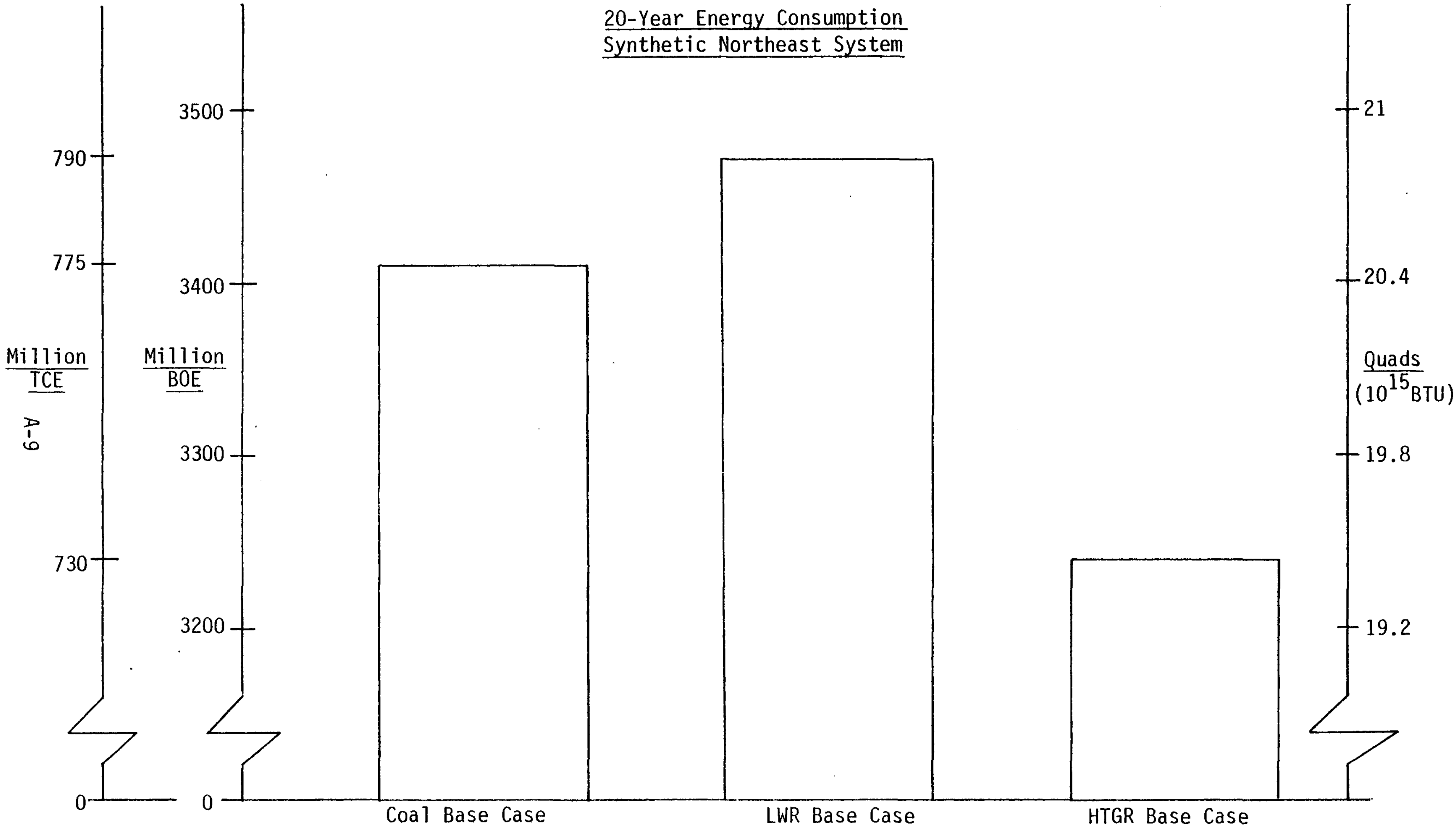


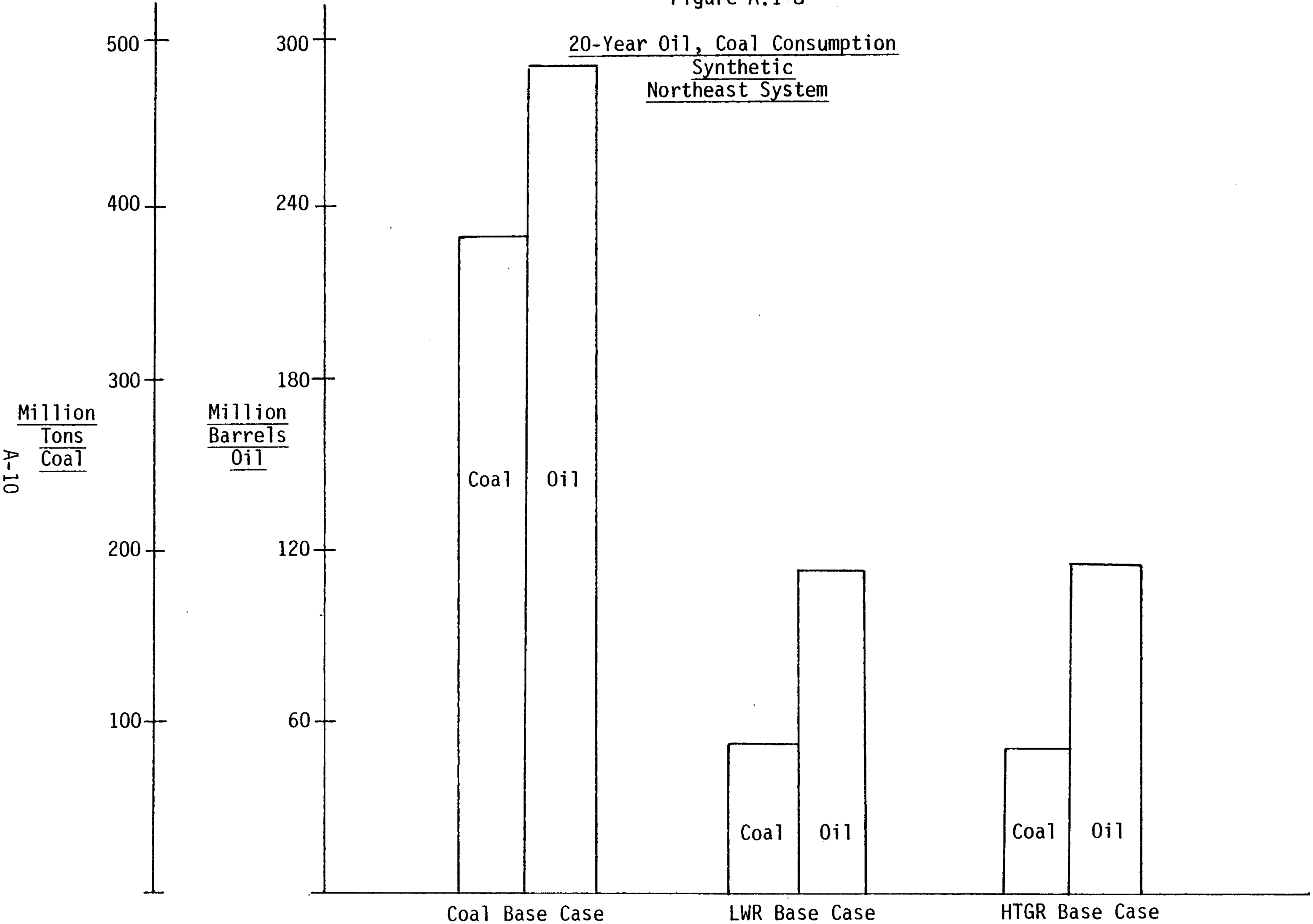
Figure A.1-7



BOE = Barrel Oil Equivalent
TCE = Ton Coal Equivalent

Figure A.1-8

20-Year Oil, Coal Consumption
Synthetic
Northeast System



Note: This figure depicts two non-equivalent scales; e.g., 240 BOE does not equal 400 TCE.

Figure A.1-9

Year 2020 Capacity Factors
Synthetic Northeast System

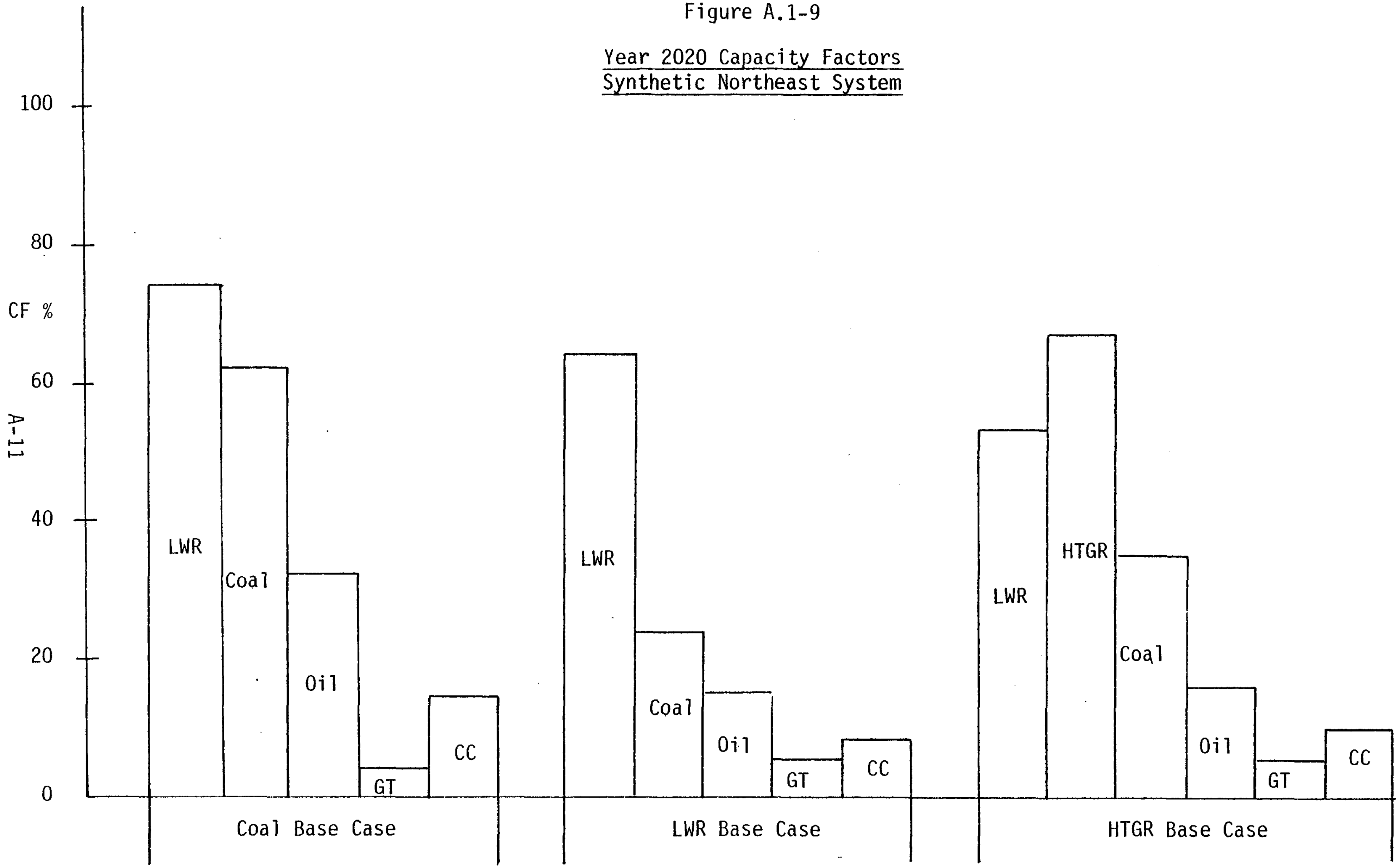


Figure A.1-10

20-Year Energy Consumption
Extrapolation to Total U.S.

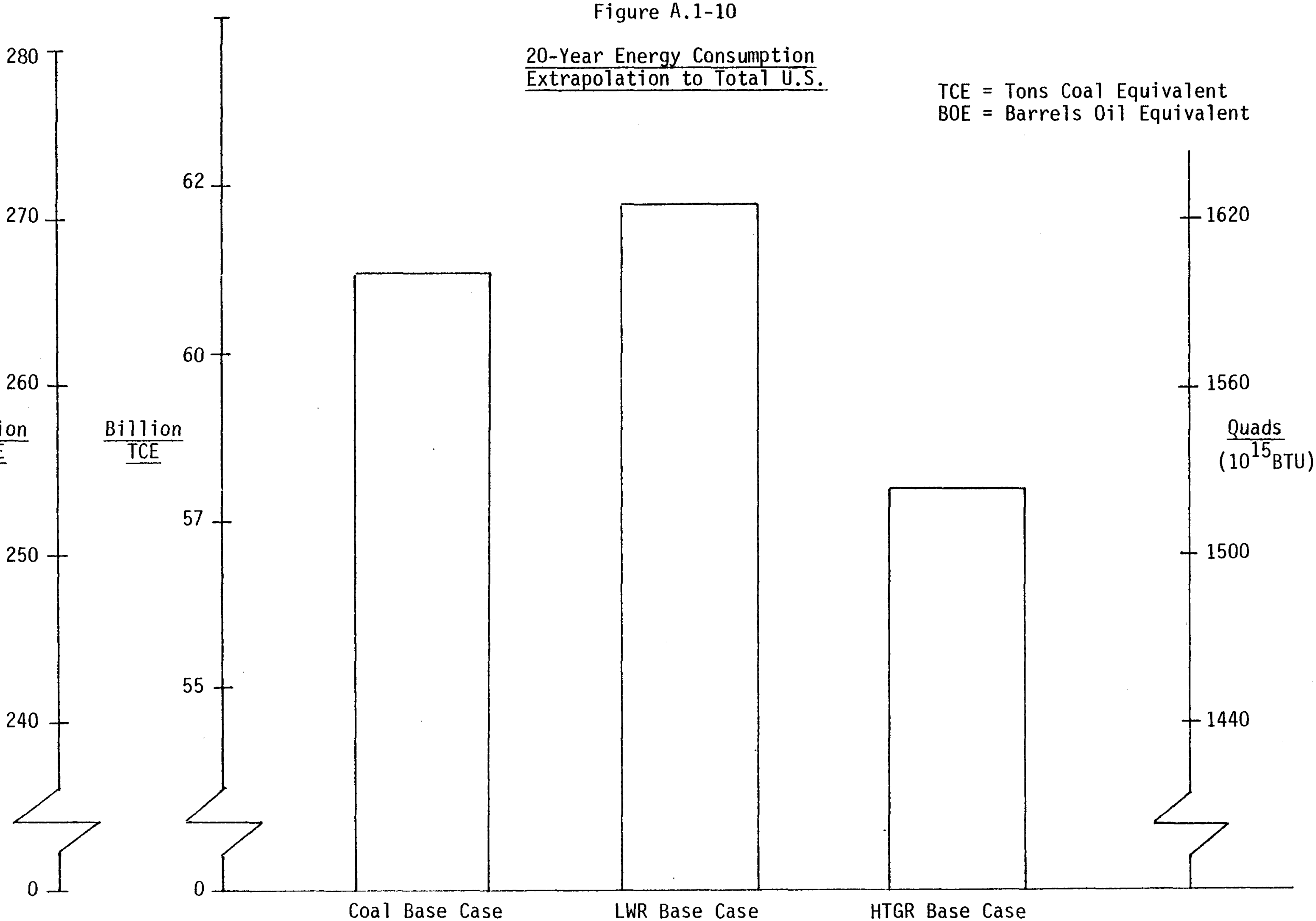
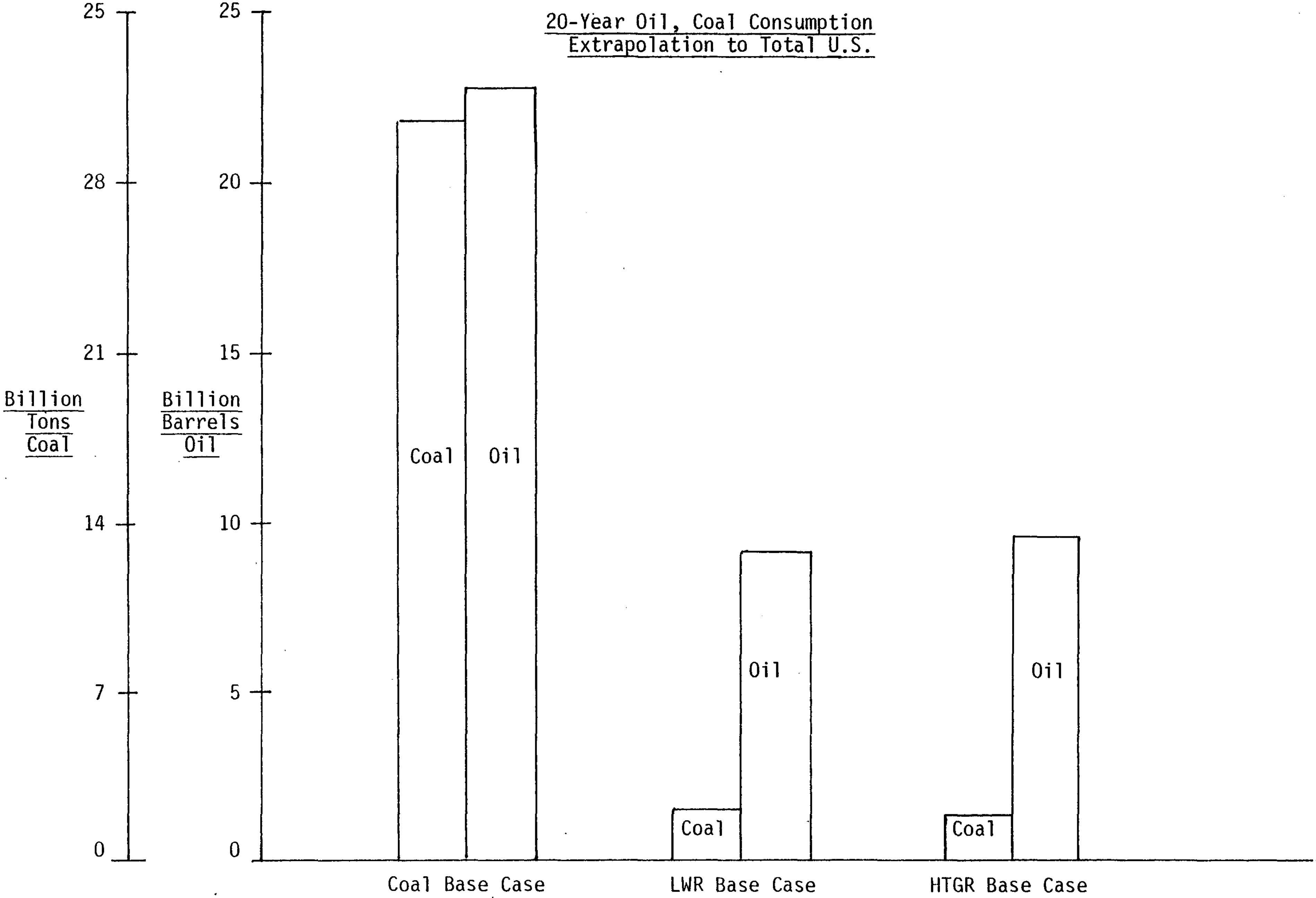


Figure A.1-11

20-Year Oil, Coal Consumption Extrapolation to Total U.S.



A.2 GENERATING UNIT COST DATA

A. Fuel Costs

Based on the TAG and utility experience as shown in Table A.2-1.

B. Operation and Maintenance Costs

Cost figures for generating unit O&M vary widely from source to source. The TAG contains cost estimates for several current technology unit types and for various advanced technology unit types which may become available in the future. The cost values are low but reasonable. The EESS costs developed by PSE&G are also reasonable but are in most cases higher than the TAG costs, particularly for fixed O&M. The Draft NASAP Provisional Data Base for U.S. Electric Utility Industry Conditions, U.S. Department of Energy, February 1979 (NASAP) contains O&M data for nuclear and coal fired generating units. The NASAP fixed O&M and coal unit variable O&M costs are higher than either the TAG or EESS costs, while the nuclear unit variable O&M costs are lower than either TAG or EESS.

Given these variations, the EESS (PSE&G) O&M costs were used for the following reasons:

1. EESS is believed to give the most complete and consistent set of O&M data of any of the reference sources, listing almost all unit types and sizes, existing and future.

2. PSE&G is a utility which does its own engineering and design, with experience in the construction and operation of nuclear, coal, and oil-fired steam, combustion turbine, and combined cycle power plants; thus, the data reflect design expectations tempered by operating experience.

3. PSE&G has performed numerous technical and economic assessments for both EPRI and DOE (and its predecessor agencies), lending their data and judgement additional credibility.

The AFB O&M costs were based on TAG, since PSE&G did not develop values for this type of unit.

Base and expansion candidate units' operation and maintenance costs are shown in Tables A.2-2 through A.2-5.

C. Capital Costs

The capital cost data are based on Reference 22. The AFB cost was based on the regionalized costs for a conventional coal unit without flue gas desulfurization. The GT and battery costs were not regionalized.

Expansion candidate unit's capital costs are shown in Table A.2-6.

D. Cost of Money

A weighted cost of money of 10% was used as the discount rate.

E. Inflation and Escalation

A general inflation rate of 6% was assumed for all costs. This value is recommended by EPRI in Reference 22 and is consistent with the 10% cost of money and the capital cost carrying charges.

An additional real escalation rate of 1% was assumed for all fuel costs. Real escalation is independent of, and in addition to, inflation. It results from factors such as resource depletion, regulation effects, etc.

Apparent escalation is the total annual increase in cost resulting from both inflation and real escalation. The apparent escalation rates resulting from the inflation and real escalation rates discussed above are:

Fuel	7%
O&M	6%
Capital	6%

Table A.2-1

Regional Fuel Costs
(EOY $/MBtu)

Year	1977	1985	2000	2020
Northeast (System D)				
Fuel: Nuclear (1)				
LWR	.54	.93	2.56	9.91
HTGR	.58	1.00	2.76	10.69
Coal	1.01	1.74	4.79	18.53
Oil - Residual, 0.5%S	2.44	4.19	11.57	44.76
Distillate	2.59	4.45	12.28	47.51

Inflation Rate	6%
Real Escalation	1%
Apparent Escalation	7%

Note: (1) Based on full recycle fuel cycles.

Table A.2-2

Base System Unit
Variable Operation and Maintenance Costs
(EOY 1977 $/MWHr)

Unit Type	Size (MW)	Region (Synthetic System) Northeast (D)	West (B)
Nuclear	1200	1.20	1.23
	1000	1.29	1.32
	800	1.41	1.45
	600	1.58	1.62
Coal	800	1.20	1.23
	600	1.35	1.38
	400	1.58	1.62
	200	2.09	2.14
Oil	800	.70	.72
	600	.78	.80
	400	.92	.94
	200	1.22	1.25
Gas Turbine	50	6.00	6.15
Combined Cycle	400	5.00	5.13
Conventional Hydro		.50	.51
Pumped Storage Hydro		.50	.51

Inflation	6%
Real Escalation	0%
Apparent Escalation	6%

Table A.2-3

Base System Unit
Fixed Operation and Maintenance Costs
(EOY 1977 $/KW-Yr)

Unit Type	Size (MW)	Region (Synthetic System) Northeast (D)	West (B)
Nuclear	1200	8.00	8.20
	1000	8.90	9.12
	800	10.25	10.51
	600	12.50	12.81
Coal	800	5.50	5.64
	600	6.50	6.66
	400	8.15	8.35
	200	12.00	12.30
Oil	800	4.95	5.07
	600	5.85	6.00
	400	7.35	7.53
	200	10.80	11.07
Gas Turbine	50	.00	.00
Combined Cycle	400	.70	.72
Conventional Hydro		.00	.00
Pumped Storage Hydro		.00	.00

Inflation	6%
Real Escalation	0%
Apparent Escalation	6%

Table A.2-4

Expansion Candidate Unit
Variable Operation and Maintenance Costs (1)
(EOY 1977 $/MWHr)

Unit Type	Size (MW)	Region (Synthetic System) Northeast (D)	West (B)
Nuclear			
LWR	1200	1.20	1.23
HTGR	1200	1.20	1.23
Coal			
Conventional w/FGD	1000	2.30	1.48
	600	2.90	1.83
Atmospheric Fluidized-Bed	1000	4.43	4.54
Gas Turbine			
Current	75	6.00	6.15
Advanced	100	6.00	6.15
Combined Cycle			
Current	250	5.00	5.13
Advanced	285	5.00	5.13
Advanced Batteries	100	3.00	3.08

Inflation	6%
Real Escalation	0%
Apparent Escalation	6%

Notes: (1) Includes consumables (lime plus sludge and ash disposal) for coal unit FGD systems.

Table A.2-5

Expansion Candidate Unit
Fixed Operation and Maintenance Costs
(EOY 1977 $/KW-Yr)

Unit Type	Size (MW)	Region (Synthetic System) Northeast (D)	West (B)
Nuclear			
LWR	1200	8.00	8.20
HTGR	1200	8.00	8.20
Coal			
Conventional w/FGD	1000	6.00	6.15
	600	8.00	8.20
Atmospheric Fluidized-Bed	1000	6.11	6.26
Gas Turbine			
Current	75	.00	.00
Advanced	100	.00	.00
Combined Cycle			
Current	250	.70	.72
Advanced	285	.70	.72
Advanced Batteries	100	.00	.00

Inflation	6%
Real Escalation	0%
Apparent Escalation	6%

Table A.2-6

Expansion Candidate Unit
Capital Costs and Carrying Charges

Unit Type	Size (MW)	Regional Capital Costs, EOY 1977 $ ($/KW) Northeast (D)	West (B) (1)	Carrying Charge (%)	Life (Years)
Nuclear					
LWR	1200	828	781/823	18	30
HTGR	1200	828	781	18	30
Coal					
Conventional w/	1000	735	715/754	18	30
FGD	600	793	772/814	18	30
Atmospheric Fluidized-Bed	1000	642	669/710	18	30
Gas Turbine	75	160	160	19	20
	100	160	160	19	20
Combined Cycle	250	330	295	18	30
	285	330	295	18	30
Advanced Batteries	100	275	275	19	20

Inflation	6%
Real Escalation	0%
Apparent Escalation	6%

Note: (1) Wet Cooled/Peak Shaved Dry-Wet Cooled. Peak Shaved Dry-Wet cooled steam units are assumed in the West after the year 2000.

A.3 END-YEAR ADJUSTMENTS

End-year adjustments must be made to output data for two key reasons. First, two systems that begin the year 2020 with unequal system reliabilities are unequal, and it is necessary to normalize these for discussion purposes. Second, operating costs for the systems continue past the final study year and must be calculated to compare systems. These two factors are described below.

A.3.1 Adjustments for Comparing Cases of Unequal System Reliabilities

Problem: One of the systems is more reliable than the other and has, therefore, incurred an unwarranted capital cost penalty.

Solution: Assume that the systems will ultimately achieve equal reliability as a result of the more reliable system installing less capacity at some future date. Quantify this by pricing out the current system excess capacity at the gas turbine cost in the last year of the study.

Example:

Northeast Expansions, 2000-2020

No Nuclear: LOLP = 9.47, excess capacity = 63 MW

LWR Option: LOLP = 8.51; excess capacity = 192 MW

Delta Excess Capacity: 129 MW

LWR Option: 9-100 MW GTs change system excess by 655 MW

1-100 MW GT = 72.8 MW of excess

Delta Excess: 129/72.8 = 1.77 GTs

GT Capital Cost:

in 1977 \$: 1.77×100 MW $\times$ 160 \$/KW $\times$ .19 = 5.38 \$ $\times 10^6$

in 2019 \$: $5.38 \times (1.06)^{42}$ = 62.18 \$ $\times 10^6$

LWR Option:

Year 2019 case investment cost = 23041.4 \$ $\times 10^6$

Year 2019 adjusted investment cost = 22979.3 \$ $\times 10^6$

Present Worth of adjustment = $62.18 \times (1/1.10)^{44}$ = 0.9 \$ $\times 10^6$

A.3.2 Adjustments for Years Beyond Study Period

Problem: Operating costs continue, with escalation, after the capital investment has been made. The effects of this are lost for units installed near the end of the study period. Note that when expressed as an annual carrying charge, investment costs do continue, but they have no escalation beyond the installation date.

Solution: Assume the end-year results will continue into the future. Implicit in this assumption are two additional assumptions: (1) no growth beyond the end year, and (2) replacement in kind as units retire.

Example:

1. Develop Present Worth/Escalation (PW/E) combined levelizing factors end-year +1 to ∞.

   PW/E rate = (1 + PW rate) ÷ (1 + Esc. rate)

   Factor: $\sum_{n = EY + 1}^{\infty} [1/(1 + PW/E)]^n$

   Capital: PW/E = (1.10 ÷ 1.00) - 1 = 10.00%

   Fuel: PW/E = (1.10 ÷ 1.07) - 1 = 2.80%

   O&M: PW/E = (1.10 ÷ 1.06) - 1 = 3.77%

2. Apply factors to end-year costs to get cumulative PW $ for the period end-year + 1 to ∞, as of EY +1.

3. Present worth from end-year +1 to base year.

4. Add to cumultive PW values from case.

Northeast 1985-2000 Expansion

	Investment	Fuel	O&M
Year 2000 $ Costs	2903.8	2981.8	893.3
Factors*	2.18	22.92	14.65
Cum 2001→∞, PW 2001	6318.7	68324.4	13086.6
Cum 2001→∞, PW 1975	530.2	5733.1	1098.1
Cum 1985-2000, PW 1975	3059.8	4471.1	1370.3
Cum 1985→∞, PW 1975	3590.0	10204.21	2468.4

*Factor, n = 1→∞	10.00	35.67	26.50
n = 1→∞	7.82	12.75	11.85
n = EY + 1→∞	2.18	22.92	14.65

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5/15/80

GENERAL ATOMIC POSITION ON THE HIGH TEMPERATURE GAS-COOLED REACTOR

1. General Atomic remains committed to gas-cooled reactors and to nuclear energy to play a major role in satisfying the U.S. and world's energy needs. GA continues to support all potential beneficial applications of the High Temperature Gas-Cooled Reactor for the following reasons:

   - The HTGR has a higher level of inherent safety that results in added plant investment protection.

   - The HTGR provides high efficiency generation of electric power.

   - The HTGR provides environmental advantages including reduced cooling water requirements, low radioactive effluent releases, and low occupational doses.

   - The HTGR is an advanced converter which provides improved resource utilization and fuel cycle flexibility.

   - The HTGR is capable of high temperature operation and is uniquely suited to coupling with many industrial processes that currently rely on fossil fuel energy sources.

2. General Atomic believes that there are significant national benefits to be derived from the development, demonstration and commercial deployment of the HTGR for all of the following specific applications:

   a. The HTGR-Steam Cycle for electric power generation for cogeneration applications involving the generation of electricity and/or process steam.

   b. The HTGR-Gas Turbine for the production of electricity using dry or wet-dry cooling, or, possibly, waste heat utilization.

   c. The HTGR-Process Heat reactor in its reforming configuration for Syngas/Hydrogen production for use in hydrogen intensive industrial processes, a chemical heat pipe application, or for providing high temperature sensible heat to other processes.

   General Atomic believes that an approach toward development and demonstration of the advanced HTGR could be via a Nuclear Heat Source Demonstration Reactor to be used for testing and demonstration of alternate primary system and process loop components.

3. General Atomic plans its role in any HTGR commercialization program to be that of the lead designer/developer of HTGR with the primary objective of establishing a business as a supplier of HTGR equipment and fabricated fuel.

4. General Atomic supports the further establishment of a broadened industrial base for HTGR subsystems and component design and supply, and intends as opportunities may arise to enlist additional qualified NHS subcontractors to undertake key elements of the program.

5. General Atomic believes that maximum practical use should be made of technology exchanges with international HTR programs, to the extent that mutual benefits are forthcoming. GA believes, however, that the U.S. program should be capable of continuing with minimum effect on cost and schedule in the event of redirection of any of the foreign programs. GA believes that the prismatic fuel design should be used for the U.S. HTGR Program.

6. General Atomic supports a strong user-oriented program, and solicits industry coordination and support through Gas-Cooled Reactor Associates and the HTGR Process Heat Users Group. Any HTGR program which is forthcoming should be coordinated around a government/industry shared cost/risk approach, with risk sharing commensurate with potential benefits foreseen by the respective participants.

ENERGY SYSTEMS AND
TECHNOLOGY DIVISION

ADVANCED REACTOR SYSTEMS DEPARTMENT

GENERAL ELECTRIC COMPANY . . . 310 DEGUIGNE DRIVE, P.O. BOX 508
SUNNYVALE, CALIFORNIA 94086

GENERAL ELECTRIC POSITION ON THE HIGH TEMPERATURE GAS-COOLED REACTOR

1. General Electric Company supports the development and demonstration of the HTGR that leads to:

   - Process applications and for both peaking and remote site electricity generation, and

   - High temperature process heat for such purposes as the production of storable/transportable fuels.

   In General Electric's opinion, these applications are the prime justification for proceeding with the development of the HTGR and the major reason GE is willing and anxious to support the Program.

2. It is recognized that for the present, the prismatic core design is the reference design for the HTGR demonstration plant. However,

   a. Parallel design efforts for the pebble bed HTGR as an alternative choice for very high temperatures should be continued as a backup to the prismatic design,

   b. Appropriate provisions should be made to permit the continued monitoring of, and interaction with, the German HTR program (including the THTR, the new 1500 MW(t) VHTR, and the Adam-Eva demonstration plants), and

   c. The selection of the final core design should be postponed as late as practicable in order to factor in any operating results of the THTR and Fort St. Vrain.

3. General Electric believes that the electric utility companies constitute an appropriate institution for the ownership and operation of these new energy generation facilities.

4. General Electric intends to work toward a broad scope of participation in this new technology.

RBR 1/31/80

Appendix C

SUMMARY OF POTENTIAL INDUSTRIAL NUCLEAR STEAM SITES

Site	General Location	Steam Load - MM#/Hr Replaceable*	Steam Load - MM#/Hr Total	Energy Use Elec. MW	Energy Use Fuel MMMBTU/D	Navigable Waterway Access
AL-1	East Side of Mobile, AL	1.8 - 2.8	3.8	196	108	Mobile Bay
AL-2	SW of Birmingham, AL	0.0 - 2.4	2.4	158	58	None
AL-3	East Central Alabama	0.3 - 0.4	0.6	26	17	Chattahoochee R.
AL-4	90 Miles NE of Mobile, AL	0.5 - 0.6	0.9	55	25	Alabama River
AL-5	25 Miles SE of Birmingham, AL	0.6 - 0.7	1.0	100	29	Coosa River
AL-6	NW of Montgomery, AL	0.4 - 0.5	0.65	25	18	Alabama River
AL-7	North Central Alabama	2.8	2.8	147	79	Tennessee River
AL-8	100 Miles N of Mobile, AL	0.3 - 0.4	0.5	14	14	Tombigbee River
AR-1	South Central Arkansas	0.8 - 1.1	1.5	64	42	None
AR-2	Pine Bluff, AR	1.4 - 1.8	2.6	110	73	None
AR-3	SW of Little Rock, AR	1.6	1.6	n.a.	44	None
CA-1	40 Miles E of Los Angeles, CA	0.0 - 0.5	0.5	130	14	None
CA-2	Mohave Desert, CA	1.25	1.25	25	35	None
CA-3	15 Miles S of Los Angeles, CA	2.7 - 4.7	5.05	198	143	San Pedro Bay
CA-4	NE of San Francisco, CA	1.1 - 1.3	1.65	83	47	Suisun Bay
CA-6	NE of San Francisco, CA	1.2 - 2.3	2.45	70	69	Suisun Bay
CA-7	25 Miles NE of SanFrancisco,CA	1.5 - 2.8	3.0	120	86	San Pablo Bay
CA-8	Northwestern California	0.3 - 0.4	0.5	21	14	Pacific Ocean
CA-9	Northwestern California	0.3 - 0.4	0.5	27	14	Pacific Ocean
CA-10	25 Miles SW of Bakersfield,CA	3.5	3.5	20	99	None
CT-1	Southeastern Connecticut	0.7	0.7	8	20	Thames River
DE-1	Northeastern Delaware	1.1 - 1.9	2.1	102	59	Delaware River
FL-1	N&E of Pensacola, FL	3.6 - 3.7	4.0	40+	113	Escambia Bay
FL-2	25 Miles S of Jacksonville, FL	0.6 - 0.7	1.0	40	28	St. Johns River
FL-3	20 Miles SE of Tampa, FL	2.05	2.05	209	58	None

SUMMARY OF POTENTIAL INDUSTRIAL NUCLEAR STEAM SITES

Site	General Location	Steam Load - MM#/Hr Replaceable*	Steam Load - MM#/Hr Total	Energy Use Elec. MW	Energy Use Fuel MMBTU/D	Navigable Waterway Access
FL-4	85 Miles E of Pensacola, FL	1.0 - 1.3	1.8	42	51	Gulf of Mexico
FL-5	Northeast Florida	0.5 - 0.7	0.95	55	27	St. Mary's River
FL-6	120 Miles SE of Pensacola, FL	0.7 - 0.8	1.2	58	34	Gulf of Mexico
FL-7	2 Miles NW of Jacksonville, FL	0.3 - 0.4	0.6	20	17	St. Johns River
GA-1	South of Valdosta, GA	0.3 - 0.4	0.55	20	15	None
GA-2	Savannah, GA	0.9 - 2.3	3.2	348	90	Savannah River
GA-3	South of Macon, GA	0.4 - 0.5	0.7	18	20	Savannah River
GA-4	60 Miles SW of Savannah, GA	0.7 - 0.9	1.3	42	37	Savannah River
GA-5	SE Corner of Georgia	0.9 - 1.2	1.7	68	48	Chattahoochee R.
GA-6	60 Miles SW of Savannah, GA	0.7 - 0.9	1.3	65	37	St. Simons Sound
GA-7	South of Augusta, GA	0.7 - 1.0	1.35	82	38	Savannah River
IA-1	Southeast Corner of IA	0.7	0.7	62	20	Mississippi River
ID-1	Norhtwest Edge of ID	0.4 - 0.6	0.8	45	23	None
IL-1	E&N Across Mississippi From St. Louis, MO	2.5 - 3.8	4.25	174	120	Mississippi River
IL-2	North of Joliet, IL	3.7 - 4.5	4.7	88	133	Des Plaines River
IL-3	25 Miles S of Champaign-Urbana, IL	1.1	1.1	35	31	None
IL-4	40 Miles SW of Terre Haute, IN	0.5 - 0.9	1.0	50	28	None
IN-1	SE Edge of Chicago, IL	1.3 - 8.6	8.8	1720+	248	Lake Michigan
IN-2	10 Miles E of Evansville, IN	0.0 - 2.5	2.5	500	71	Ohio River
IN-3	10 Miles N of Muncie, In	0.3 - 0.4	0.6	n.a.	17	None
KY-2	Northeastern Kentucky	0.4 - 0.6	0.7	.33	20	Ohio/Big Sandy Rs.
KY-3	SW Corner of Louisville, KY	0.8	0.8	35+	23	Ohio River

SUMMARY OF POTENTIAL INDUSTRIAL NUCLEAR STEAM SITES

Site	General Location	Steam Load - MM#/Hr Replaceable*	Steam Load - MM#/Hr Total	Energy Use Elec. MW	Energy Use Fuel MMMBTU/D	Navigable Waterway Access
LA-1	18 Miles N of Baton Rouge, LA	0.9 - 1.1	1.6	30	45	Mississippi River
LA-2	10 Miles S of Baton Rouge, LA	7.7 - 7.1	8.4	348	237	Mississippi River
LA-3	Southwest Louisiana	5.5 - 5.65	5.75	374	162	Calcasieu River
LA-4	55 Miles E of Shreveport, LA	0.7 - 0.9	1.3	80	37	None
LA-5	50 Miles N of New Orleans, LA	0.7 - 0.8	1.2	50	34	Pearl River
LA-6	6 Miles E of New Orleans, LA	2.7 - 4.9	5.35	587	151	Mississippi River
LA-7	South Central Louisiana	0.4 - 0.5	0.65	22	18	Red River
LA-8	10 Miles SE of New Orleans, LA	0.6 - 1.0	1.1	32	31	Lower Mississippi R.
LA-9	North Part of Baton Rouge, LA	4.0	4.0	454	113	Mississippi River
LA-10	20 Miles S of Baton Rouge, LA	4.7 - 4.9	5.05	596	143	Mississippi River
LA-11	25 Miles W of New Orleans, LA	5.4 - 5.8	5.9	460	167	Mississippi River
LA-12	60 Miles SE of New Orleans, LA	0.3 - 0.55	0.55	7	16	Lower Mississippi R.
LA-13	20 Miles N of Baton Rouge, LA	0.5 - 0.7	0.95	56	27	Mississippi River
LA-14	North Central Louisiana	1.0 - 1.3	1.8	52	51	None
LA-15	Northern Louisiana	1.0 - 1.3	1.8	79	51	None
MD-1	20 Miles SW of Cumberland, MD	0.6 - 0.8	1.2	45	34	None
MD-2	3 Miles SE of Baltimore, MD	0.8 - 1.6	1.6	253	45	Patapsco River
ME-1	Western Edge of Portland, ME	0.3 - 0.4	0.6	24	17	None
ME-2	60 Miles N of Portland, ME	0.3 - 0.4	0.6	48	17	None
ME-3	70 Miles NW of Portland, ME	0.3 - 0.4	0.6	29	17	None
ME-4	NE Corner of Maine	0.4 - 0.5	0.7	35	20	None
ME-5	Eastern Maine	0.5 - 0.6	0.85	44	24	None
ME-6	East Central Maine	0.8 - 1.1	1.5	21	42	None
MI-1	Central Michigan	2.5	2.5	100	71	None
MI-2	Southwestern Michigan	0.3 - 0.4	0.5	23	14	Lake Michigan
MI-3	NW Edge of Lower Peninsula	0.4 - 0.6	0.8	21	23	Lake Michigan
MI-4	SW Part of Upper Michigan	0.6 - 0.7	1.0	50	28	Lake Michigan
MI-6	Southern Edge of Detroit	1.1 - 3.6	3.6	464	102	Detroit River

SUMMARY OF POTENTIAL INDUSTRIAL NUCLEAR STEAM SITES

Site	General Location	Steam Load - MMl/Hr		Energy Use		Navigable Waterway Access
		Replaceable*	Total	Elec. MW	Fuel MMMBTU/D	
MN-1	Northern Minnesota	0.5 - 0.6	0.9	40	25	None
MN-2	South of Minneapolis, MN	0.3 - 0.6	0.6	29	17	Mississippi River
MO-1	NE Kansas City, MO	0.5 - 0.8	0.9	25	25	Missouri River
MO-3	St. Louis, MO	0.7	0.7	25	20	Mississippi River
MS-1	East of Pascagula, MS	1.7 - 2.3	2.7	103	76	Intracostal Waterway
MS-2	35 Miles N of Hattiesburg, MS	0.6 - 0.7	1.0	50	28	None
MS-3	50 Miles W of Hattiesburg, MS	0.7 - 0.8	1.2	45	39	None
MT-1	West Central Montana	0.7 - 0.9	1.3	24	37	None
NC-1	60 Miles NE of Raleigh, NC	0.4 - 0.5	0.75	35	21	Roanoke River
NC-2	18 Miles NW of Wilmington, NC	0.6 - 0.7	1.0	40	28	Cape Fear River
NC-3	Northeastern North Carolina	0.7 - 0.8	1.2	53	34	Roanoke River-Albemarle Sound
NC-4	Western North Carolina	0.9 - 1.2	1.7	72	48	None
NC-5	Southwestern North Carolina	0.85	0.85	7	24	None
NC-6	35 Miles NE of Charlotte, NC	0.5	0.5	n.a.	14	None
NJ-1	South of Elizabeth, NJ	2.0 - 2.4	2.5	101	71	Arthur Kill
NJ-2	East of Wilmington, DE - Across Delaware River	1.2	1.2	20	34	Delaware River
NJ-3	Southwest of Camden, NJ	1.1 - 1.9	2.0	48	56	Delaware River
NY-1	North of Buffalo, NY	0.2 - 0.4	0.4	17	11	E. Niagara River
NY-2	40 Miles E of Niagara Falls, NY	0.3 - 0.4	0.5	17	14	None
NY-3	Northeast New York State	0.4 - 0.5	0.7	2	20	None
NY-4	Rochester, NY	2.5	2.5	125	71	None
NY-5	30 Miles N of Schenectady	0.3 - 0.4	0.5	19	14	None
NY-6	East of Syracuse, NY	1.4 - 1.4	1.4	40	39	None

SUMMARY OF POTENTIAL INDUSTRIAL NUCLEAR STEAM SITES

Site	General Location	Steam Load - MM#/Hr Replaceable*	Steam Load - MM#/Hr Total	Energy Use Elec. MW	Energy Use Fuel MMMBTU/D	Navigable Waterway Access
NY-7	SE of Niagara Falls, NY	0.7	0.7+	171+	20+	Niagara River
NY-8	South Buffalo, NY	0.0 - 1.5	1.5	175	42	Lake Erie
OH-1	20 Miles NE of Cleveland, OH	1.5	1.5	34	42	Lake Erie
OH-2	42 Miles S of Columbus, OH	0.4 - 0.6	0.8	74	23	Scioto River
OH-3	4 Miles SW of Akron, OH	1.3	1.3	48	37	None
OH-4	Cincinnati, OH	0.65	0.65	n.a.	18	None
OH-5	West Central Ohio	0.6 - 0.8	0.9	42	25	None
OH-6	East of Toledo	0.7 - 1.2	1.3	68	37	Naumee R.-Lake Erie
OK-1	South Central Oklahoma	0.8 - 1.0	1.5	65	42	None
OK-2	North Central Oklahoma	0.4 - 0.7	0.8	26	23	None
OR-1	100 Miles SW of Portland, OR	0.4	0.6	20	18	None
OR-2	40 Miles NW of Portland, OR	0.3 - 0.4	0.6	75	17	Columbia River
OR-3	East of Eugene, OR	0.6 - 0.7	1.0	50	28	None
OR-4	50 Miles SW of Eugene, OR	0.3 - 0.4	0.55	18	16	Winchester Bay
PA-1	Philadelphia River Front	3.2 - 5.0	5.5	165+	155	Delaware River
PA-2	25 Miles S of Harrisburg, PA	0.3 - 0.4	0.6	31	17	None
PA-3	25 Miles NW of Pittsburgh, PA	0.5 - 0.9	1.0	20	28	Ohio River
PA-4	North of Philadelphia, PA	0.0 - 0.6	0.6	450	17	Delaware River
SC-1	East of Rock Hill, SC	1.5 - 1.6	1.85	132	54	None
SC-2	Northeast Charleston, SC	1.3 - 1.7	2.4	100	68	Charleston Harbor
SC-3	Georgetown, c	1.3 - 1.7	2.4	100	68	Winyah Bay
TN-1	37 Miles NE of Chattanooga, TN	0.5 - 0.7	0.9	225	25	Tennessee River
TN-2	65 Miles N of Asheville, NC	0.4 - 0.5	0.6	54	17	Holston River
TN-3	70 Miles E of Chattanooga, TN	0.0 - 0.5	0.5	208	14	None

SUMMARY OF POTENTIAL INDUSTRIAL NUCLEAR STEAM SITES

Site	General Location	Steam Load - MM#/Hr Replaceable*	Steam Load - MM#/Hr Total	Energy Use Elec. MW	Energy Use Fuel MMBTU/D	Navigable Waterway Access
TX-1	40 Miles SE of Houston, TX	6.0 - 7.7	8.0	302	226	Galveston Bay
TX-2	15 Miles NE of Houston, TX	0.6 - 0.7	1.0	95	20	None
TX-3	120 Miles NE of Houston, TX	1.2 - 1.6	2.2	100	63	None
TX-4	20 Miles N of Beaumont, TX	0.7 - 0.8	1.2	52	34	None
TX-5	22 Miles E of Beaumont, TX	0.3 - 0.4	0.5	25	14	Sabine River
TX-6	10 Miles E of Houston, TX	15.6 - 17.0	17.3	1236	488	Houston Ship Channel
TX-7	Southeast of Beaumont, TX	15.1 - 17.8	18.3	494+	517	Sabine Lake - Neches Lake
TX-8	60 Miles S of Houston, TX	9.2	9.2	1210	259	Brazos River
TX-9	30 Miles S of Houston, TX	1.2	1.2	60	34	Chocolate Bayou
TX-10	E of Corpus Christi, TX	4.4 - 5.2	5.4	102	152	Corpus Christi Bay
TX-11	140 Miles SW of Houston, TX	1.6	1.6	55	45	None
TX-12	100 Miles SW of Houston, TX	4.0	4.0	350	113	Lavaca Bay
TX-13	140 Miles NW of Houston, TX	0.0 - 2.5	2.5	500	71	None
TX-14	65 Miles SW of Houston, TX	1.0	1.0	10	28	Colorado River
TX-15	50 Miles ENE of Amarillo, TX	1.0	1.0	10	28	None
TX-16	25 Miles SW of Corpus Christi, TX	2.0	2.0	17	56	NOne
TX-17	50 Miles W of Shreveport, LA	1.0 - 2.0	2.0	20	56	None
UT-1	N Edge of Salt Lake City, UT	0.4 - 0.6	0.75	28	21	None
UT-2	15 Miles W of Salt Lake City, UT	0.0 - 1.7	1.7	200	48	None
VA-1	20 Miles SE of Richmond, CA	0.3 - 0.4	0.5	30	14	James River
VA-2	30 Miles SW of Norfolk, VA	0.4 - 0.6	0.8	52	23	None
VA-3	40 Miles SW of Washington, DC	1.1	1.1	n.a.	31	None
VA-4	70 Miles W of Washington, DC	0.9	0.9	23	25	None
VA-5	South of Richmond, VA	0.55	0.55	n.a.	16	None
VA-6	20 Miles N of Roanoke, VA	0.8 - 1.1	1.5	50	42	None
VA-7	40 Miles W of Roanoke, VA	0.6 - 0.7	1.0	-	28	None

SUMMARY OF POTENTIAL INDUSTRIAL NUCLEAR STEAM SITES

Site	General Location	Steam Load - MM#/Hr Replaceable*	Steam Load - MM#/Hr Total	Energy Use Elec. MW	Energy Use Fuel MMMBTU/D.	Navigable Waterway Access
WA-1	25 Miles N of Seattle, WA	0.5 - 0.6	0.9	31	25	Saratoga Pass - Puget Sound
WA-2	40 Miles N of Portland, OR	0.4 - 0.5	0.7	70	20	Columbia River
WA-3	20 Miles N of Portland, OR	1.0 - 1.3	1.8	64	51	Columbia River
WA-4	80 Miles N of Seattle, WA	0.3 - 0.5	0.55	67	16	Puget Sound
WA-5	60 Miles N of Seattle, WA	0.5 - 0.8	0.9	28	25	Puget Sound
WI-1	South of Green Bay, WI	0.5 - 0.6	0.9	38	25	Fox River-Green Bay
WI-2	Central Wisconsin	0.3 - 0.4	0.5	20	14	None
WV-1	6 Miles W of Charleston, WV	4.8	4.8	211	136	Kanawha River
WV-3	50 Miles SW of Pittsburgh, PA	0.5	0.5	12	14	Ohio River
WV-4	South of Wheeling, WV	1.4	1.4	167	39	Ohio River
WV-5	30 Miles W of Pittsburgh, PA	0.0 - 0.55	0.55	n.a.	16	Ohio River
WY-1	Southwestern Wyoming	2.0	2.0	49	56	None
WY-2	Southwestern Wyoming	0.5	0.5	13	14	None
WY-3	Southwestern Wyoming	0.5	0.5	12	14	None

*Excludes steam from self-generated fuels (process residuals).