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ENGINEERS

May 2, 2008

Mr. Phil Mills
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P.O. Box 1625, MS 3890
Idaho Falls, ID 83415-3890

Subject: MPR-3181, "Survey of HTGR Process Energy Applications," Revision 0

Dear Mr. Mills:

Enclosed please find Revision 0 of Report MPR-3181, "Survey of HTGR Process Energy Applications," This report is transmitted in accordance with Amendment No. 6 to BEA Contract No. 64578.

Please feel free to contact Joey Konefal at (703) 519-0548 or me directly at (703) 519-0533 should you have any questions.

Sincerely,

Dave Rackiewicz

Dave Rackiewicz

Enclosure

cc: L. Demick, INL
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G. Gibbs, INL

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MPR-3181
Revision 0
May 2008

Survey of HTGR Process Energy Applications

Prepared for

NGNP Project - Batelle Energy Alliance

MPR ASSOCIATES INC.
ENGINEERS

Survey of HTGR Process Energy Applications

MPR-3181
Revision 0

May 2008

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NGNP Project - Batelle Energy Alliance

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Executive Summary

This report provides a preliminary survey of the process energy usage of the commercial industry in applications relevant to High Temperature Gas-Cooled Reactor (HTGR) technology.

A screening assessment of industrial sectors and their manufacturing processes was performed to identify and prioritize the industries of interest, as shown in Table 1. Priorities were based on energy demands and process temperatures as defined below:

- High Priority industries have both high energy demands and suitable process temperatures (250°C to 950°C). Often, these industries will feature multiple processes with these characteristics or high growth expectations.

- Medium priority industries have a smaller energy demand for processes with suitable process temperatures or require process modification to reach suitable process temperatures.

- Low priority industries have either low energy demands per manufacturing plant or employ processes with temperatures outside the 250°C to 950°C range.

Within the industries that were assessed as either high or medium priority, specific products and processes were identified for further consideration. Because the application of HTGR technology to industrial processes will require varying amounts of technology development, each application was classified as "near-term" or "far-term."

- Near-term applications are those which are currently in use on an industrial scale and can incorporate HTGR process energy without significant technology development.

- Far-term applications are either not currently in use on an industrial scale or have production methods that would require significant technology development to incorporate HTGR process energy.

An obvious near-term application would be the use of the HTGR as a cogeneration plant to deliver steam and electricity. If hot gas or hydrogen generated in the HTGR could be directly substituted into a process, this application is also considered near-term.

An obvious far-term application would be thermo-chemical water splitting, which has not been demonstrated on an industrial scale. The use of HTGR heat for coal gasification would also be far-term, as existing industrial equipment generates heat by the partial oxidation of the feedstock, thereby requiring the development of new process technology to incorporate HTGR heat.

Table 2 lists the specific products and processes identified for further consideration according to their process temperature. The shaded products and processes are far-term applications.

Table 1. Screening Evaluation Results

Industry	Assessment	Priority
Petroleum Refining	Multiple refining processes have very high energy demands and suitable process temperatures.	High
Oil Recovery	In-situ bitumen extraction has a high energy demand, suitable process temperature, and high growth expectations.	High
Coal and Natural Gas Derivatives	Syngas, hydrogen, and liquid fuel production from coal and natural gas has suitable process temperatures and high projected growth.	High
Petrochemicals	Multiple petrochemical production processes have very high energy demands and suitable process temperatures.	High
Industrial Gases (Hydrogen)	Steam methane reforming and advanced hydrogen production methods have high energy demands and suitable process temperatures.	High
Fertilizers (Ammonia, Nitrates)	Ammonia production has high energy demand and suitable process temperatures.	High
Metals	Direct-reduced iron (DRI) production has high energy demands, suitable process temperatures and strong global growth.	High
Polymer Products (Plastics, Fibers)	Certain polymers have large energy demands at suitable process temperatures while most do not.	Medium
Cement	The current cement process temperatures are too high, but production is possible at suitable temperatures with technology development.	Medium
Pharmaceuticals	The process energy needs of the pharmaceutical industry on a per plant basis are relatively low.	Low
Paper	The typical energy requirement for a mill is low and byproducts, having little value otherwise, are burned to provide half of the steam and electricity needs of paper producers.	Low
Glass	Glass production process temperatures are too high.	Low

Table 2. Processes, Products, and Temperatures Applicable to HTGR Technology*

250-500˚C		500-700˚C		700-950˚C	
Product	**Process**	**Product**	**Process**	**Product**	**Process**
Refinery Products	Atmospheric Distillation	Petroleum Coke	Coking	Ethylene	Steam Cracking
	Vacuum Distillation	Refinery Products	Catalytic Cracking	Propylene	
	Catalytic Hydro Cracking	Refinery Products	Catalytic Reforming	Hydrogen	Steam Methane Reforming
	Hydro-Treating			Carbon Dioxide	
Bitumen	In-Situ Bitumen Extraction	Benzene		*Hydrogen*	*HTSE, S-I, HyS*
Acetone	Rearrangement of Cumene Hydroperoxide	Toluene		*Cement (with catalyst)*	*Calcination*
Acrylonitrile	Ammoxidation	P-Xylene		*Syngas*	*Gasification*
Ethylbenzene	Friedel-Crafts Alkylation	Synthetic Crude Oil	Bitumen Upgrading	*Direct Reduced Iron*	
Ethylene Oxide	Air Epoxidation	Styrene	Dehydrogenation		
Acetic Acid	Multiple	*Hot Briquetted Iron*	*Gasification*		
Cumene	Friedel-Crafts Alkylation				
Cyclohexane	Transformation of Benzene				
Terephthalic Acid	Amoco Process				
Ammonia	Haber Process				
Low-Density Polyethylene	Polymerization				
Nylon 6 and Nylon 6.6					
Polyester					
Liquid Fuels	*Fischer-Tropsch*				

*Unshaded applications are classified as near-term. Shaded applications are far-term.

An estimation of the total annual energy usage in the United States for near-term applications is shown in Figure 1. Applications to oil recovery in the Canadian oil sands are also included. Most of these applications require temperatures below 700˚C. The current applications above 700˚C are a small fraction of the total energy in the HTGR temperature range. Steam methane reforming to produce hydrogen and steam cracking to produce ethylene and propylene are the highest temperature applications shown in Figure 1.

The amount of 500 MWt HTGR modules required to meet these energy demands (assuming 85% capacity) is shown in Figure 2. An estimation of the CO_2 emissions from these near term applications that could be avoided using HTGR technology is provided in Figure 3.

The in-situ recovery of bitumen from Oil Sands shows the highest potential for growth in North America. Based on projections by the Canadian Association of Petroleum Producers, the annual energy demand for this application will increase from 175 TBtu in 2006 to 645 TBtu by 2020 (~fifty 500 MWt HTGR modules).

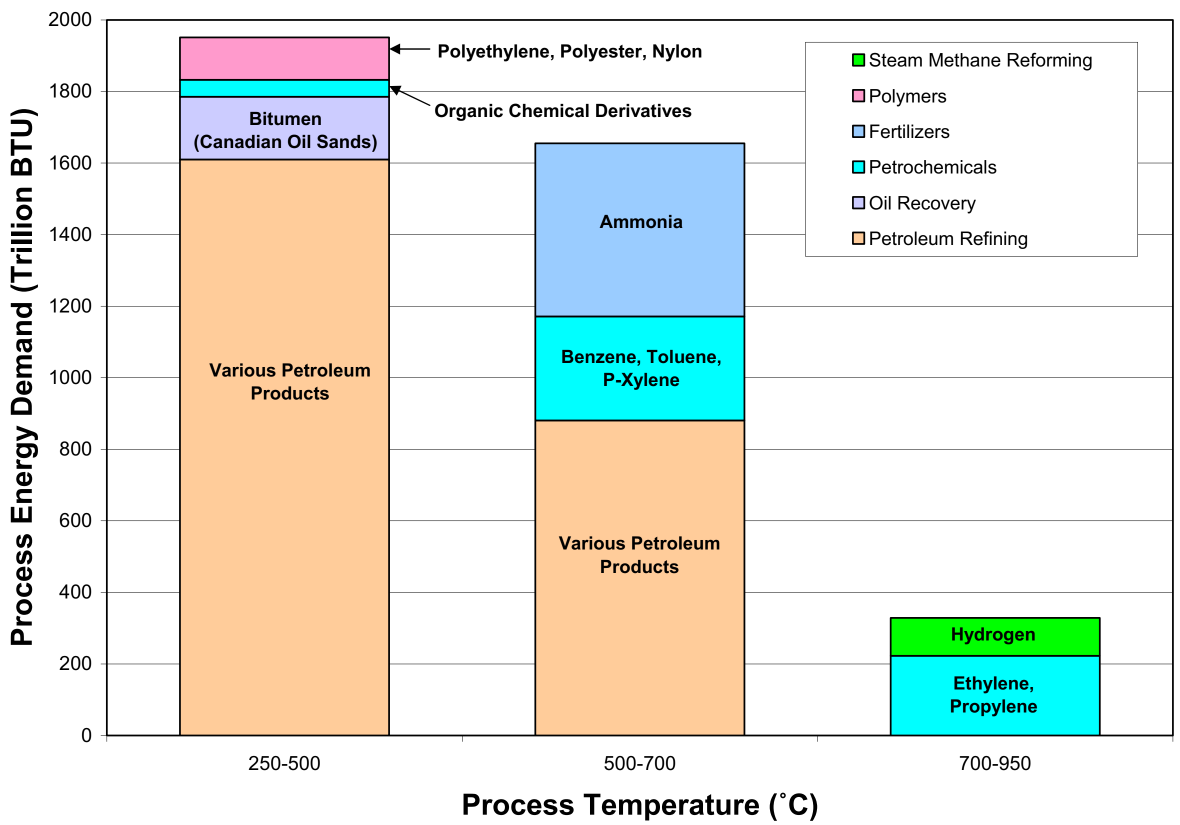

Figure 1. Near-term HTGR Application Annual U.S. Energy Demand vs. Temperature (2000-2007)

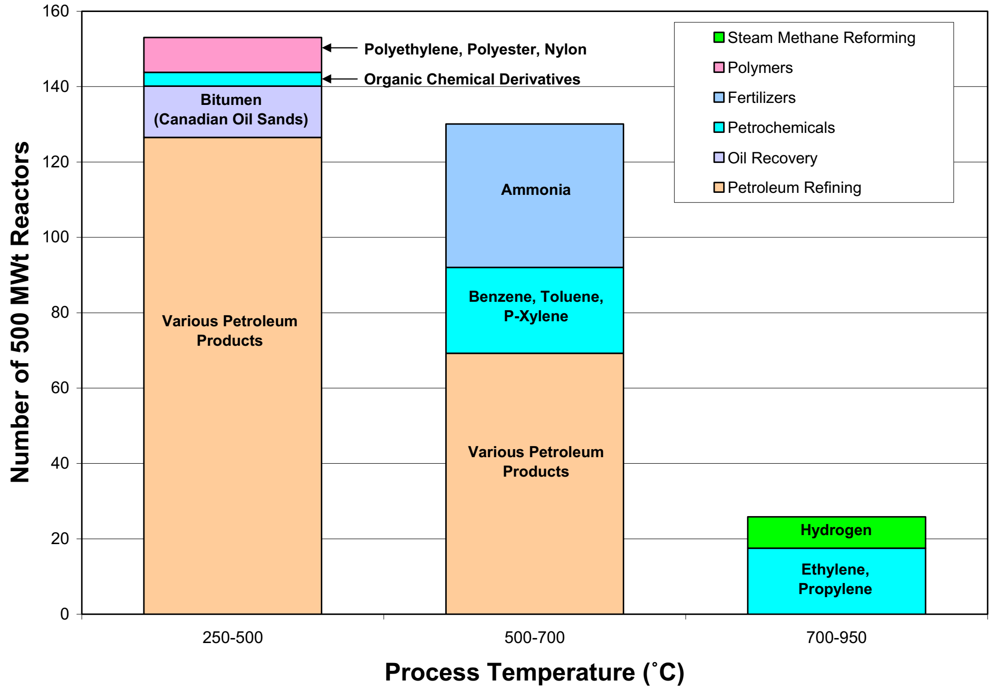

Figure 2. Number of 500 MWt HTGR Modules at 85% Capacity Required to Meet Demands (2000-2007)

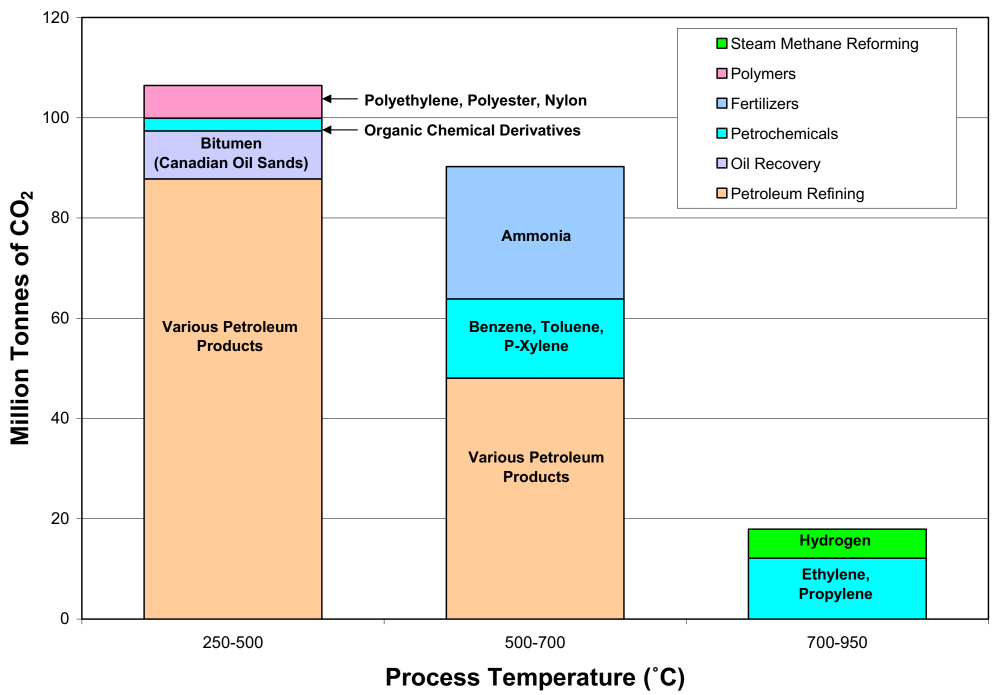

Figure 3. Potentially Avoidable Annual U.S. CO_2 Emissions from Near-term Applications (2000-2007)

The products and processes for near-term applications were reviewed with respect to plant thermal demand. Based on the preliminary energy, reliability and site requirements for near-term HTGR applications, the following conclusions were reached with respect to total thermal plant and module size for typical applications:

- The thermal demand for a typical 200,000 bpd complex coking refinery is approximately 1100 MWt (7% steam, 76% heat, 17% electricity). Refining reliability requirements would suggest that a minimum of three modules be provided. The production capacity of the refinery will dictate the number of modules required. An acceptable module size would be in the range of 400-600 MWt.

- The thermal demand for 100,000 bpd of in-situ bitumen extraction is approximately 1270 MWt (over 90% steam). Reliability requirements would suggest that a minimum of two modules be provided. A module size of 400-600 MWt could extract approximately 60 to 90 thousand bpd of bitumen.

- The thermal demand for a 100 million scfd steam methane reforming unit is approximately 130 MWt (56% steam, 37% heat, 7% electricity). Given the small module size that would be required for this application, it is likely that it would be coupled with other applications, such as electricity and steam production for other processes.

This report establishes a format for incorporating additional information. A survey of the companies engaging in the various production methods should be conducted to augment and clarify the analysis of the near-term applications. In addition, it is suggested that the technology development requirements and prospective growth trends of far-term applications be evaluated further.

Contents

Tables

Figures

1 Introduction

1.1 Background

The Next Generation Nuclear Plant (NGNP) Project is developing the basis for selecting the design, initial operating conditions and nuclear heat supply configuration for a High Temperature Gas-Cooled Reactor (HTGR). One task is to establish what reactor size and operational characteristics would best satisfy the industrial process energy requirements in the private sector. To support this determination, the potential applications of HTGR process energy to industrial processes were investigated.

1.2 Methodology

The first step in the investigation was a screening assessment of industrial sectors and their manufacturing processes. This screening identified key sectors, processes, and products, for further pursuit. It was based on broad-spectrum factors such as annual energy demand and process temperatures. Input for this evaluation was provided primarily by government reports, textbooks, and technical papers on manufacturing processes. In addition, meetings were conducted with three HTGR vendors (AREVA, Westinghouse/PBMR, and General Atomics). The meeting reports are provided in Appendices A-C. The screening assessment is provided in Section 2 of this report.

Based on the results of the screening assessment, various processes and products were selected for further analysis. The energy requirements of the selected processes and products were analyzed, and if possible, the estimated demand for individual process plants was estimated. In addition, the cogeneration of heat, steam and electricity for each identified industry is also discussed. Finally, the reliability and siting requirements of each application were discussed. This analysis is provided in Section 3 of this report. A survey of the companies engaging in these production methods is planned. This will ultimately serve to augment and clarify this analysis.

2 Screening

2.1 RESULTS

Table 2-1 summarizes the industrial applications that were screened, the results of the screening in the priority of interest, and top companies within each industry of interest.

Table 2-1. Screening Evaluation Results

Industry	Priority	Top Companies[1]
Petroleum Refining	High	Note 1
Oil Recovery	High	Note 1
Coal and Natural Gas Derivatives	High	Note 1
Petrochemicals	High	Note 1
Industrial Gases (Hydrogen)	High	Praxair Air Products
Fertilizers (Ammonia, Nitrates)	High	CF Industries Holdings, Inc. PCS Nitrogen
Metals	High	Midrex Technologies
Polymer Products (Plastics and Fibers)	Medium	Note 1
Cement	Medium	Lehigh Cement Titan America
Pharmaceuticals	Low	Note 2
Paper	Low	Note 2
Glass	Low	Note 2

Note 1: The NGNP project has already established relationships with companies in these sectors.
Note 2: These sectors are not being considered for HTGR applications.

2.2 SCREENING APPROACH

2.2.1 Largest Users of Energy and Process Heat

The largest manufacturing industries in terms of energy and process heat use were considered the highest priority for the potential application of HTGR technology. Based on a review of the U.S. manufacturing sector, five sectors were selected to be screened: 1) petroleum, coal and natural gas products, 2) chemicals, 3) primary metals, 4) paper, and 5) non-metallic mineral products.

Table 2-2 identifies the industries that were screened and provides the energy consumed as fuel by each of these industries. The industries listed in Table 2-2 consume the most energy in the United States. Moreover, they include the highest consumers of process heat. In 1995, greater than 80% of the consumption of process heat was in the same five industries (Reference 1).

2.2.2 Temperatures of Interest

For each industrial sector, process temperatures were evaluated. In some cases, the general process was addressed rather than each specific product that could be produced from the process. In other cases, products were specifically considered.

Process temperature is the primary screening criterion. The HTGR technology is uniquely suited for temperatures that are from 250˚C to 950˚C. This range is higher than the typical temperature range of water-cooled reactor technology. Processes at these temperature ranges would help to determine the value that could be provided at the maximum operating temperature of the HTGR. Applications with temperatures under 250˚C could also be factors in determining the total value of nuclear produced heat for the end-user and in determining the total size of the HTGR. Temperatures higher than 950˚C are of less interest because they are higher than HTGR coolant temperatures and additional electric or combustion heat would have to be added to meet the needs of the industrial process.

2.2.3 Total Energy Demand

For a process that used temperature ranges of interest for HTGR technology application, the amount of energy used was estimated based on information available in the commercial literature. This information included plant size, energy consumed as fuel, number of plants/establishments, yearly production, product shipment value, and growth forecasts.

Further evaluations of total energy demand, as they relate to degree of interest for HTGR technology, are contained in Section 3 below.

Table 2-2. Energy Usage by Industrial Sector (Reference 2)

Industrial Sector	Industrial Subcategories	Energy Consumed as Fuel in 2002 (TBtu)*
Petroleum, Coal and Natural Gas	Petroleum Refining Coal and Natural Gas Derivatives Oil Recovery	3,202
Chemicals	Petrochemicals Industrial Gases Synthetic Rubber Plastics Noncellulosic Organic Fibers Fertilizers Pharmaceuticals	3,769
Paper	Pulp Mills Paper Mills	2,361
Metals	Ore Processsing Primary Metals	2,123
Nonmetallic Mineral Products	Glass Cements	1,052

Note: *TBtu = Trillion Btu or 10^6 MMBtu

2.3 INDUSTRIAL APPLICATIONS

2.3.1 Petroleum, Coal and Natural Gas

Petroleum Refining

The petroleum refining industry is one of the largest energy users in the United States. In 2002, U.S. refineries consumed 6,400 TBtu of energy (Reference 2). 145 petroleum refineries were operating in 2007 (Reference 3). Approximately one-third of these refineries employed the use of cogeneration of electricity technologies (Reference 2).

Over 2,000 products made to individual specifications are developed from petroleum refineries (Reference 3). The products with the highest production quantities are gasoline, diesel, jet fuel, and home heating oils.

Table 2-3 lists petroleum refining processes such as catalytic cracking and reforming and details their use and process requirements. The temperatures for these processes are generally around 500-600˚C, though they can extend to 950˚C.

The U.S. refining market includes large, vertically-integrated companies that explore, transport, refine, and market within the petroleum sector as well as smaller companies more focused on refining and marketing, only. Table 2-4 lists the top 20 refiners in the U.S.

***Interest Level**: High* - Petroleum refining employs many processes that require large amounts of process heat at temperatures from 250-950˚C that match well with HTGR technology.

Oil Recovery

Enhanced Oil Recovery

Enhanced oil recovery is performed to increase recovery yields after oil has been extracted from the ground using traditional methods. There are two primary methods: gas injection and thermal recovery. With gas injection, CO_2, natural gas, or nitrogen expands and moves the oil deposits to a wellbore so that they can be pumped out of the ground. With thermal recovery, steam is injected into the ground to heat up and thereby reduce the viscosity of the oil deposits.

Babcock and Wilcox currently markets oil recovery steam generators that are pre-engineered for thermal outputs of 1.5 to 14.7 MWt, pressures up to 17MPa, temperatures up to ~350°C and steam rates up to 250,000 lb/h (Reference 4).

Studies by General Atomics indicate that 900 MWt and 1 MW(e) for pumping can produce 35,000 bbls of oil per day at process conditions of 250˚C and 3.5 MPa (Appendix C).

Most thermal recovery operations in the U.S. take place in California and include the cogeneration of electricity. In 1998, there were 10 oil fields with 42 thermal recovery projects. 63% of the steam was produced by cogeneration technologies (Reference 5).

Bitumen Extraction and Upgrading (Oil Sands)

The oil sands of Alberta, Canada contain bitumen, which can be extracted and then upgraded to synthetic crude oil (SCO). The proven reserves of the oil sands equate to 174 billion barrels of oil. Of these reserves, 18% can be recovered by surface mining while the remaining 82% can only recovered by in-situ extraction methods (Reference 6).

In-situ extraction methods involve the use of thermal energy to decrease the viscosity of the bitumen and allow for its extraction. As with enhanced oil recovery, this energy is usually in the form of steam. These methods include cyclic steam stimulation (CSS), pressure cyclic steam drive (PCSD) and steam assisted gravity drainage (SAGD) (Reference 6). The temperature of the steam required is greater than 300˚C and the pressure is in the range of 8-16 MPa (Appendix B).

The upgrading of bitumen into SCO involves the implementation of the petroleum refining processes detailed in Table 2-3 such as thermal and catalytic cracking.

In 2006 production of bitumen from oil sands was at 1.26 million bpd (Reference 7). The Canadian Association of Petroleum Producers expects production to reach 4 million bpd by 2020 (Reference 8).

Kerogen Retorting and Upgrading (Oil Shale)

Oil shale is a sedimentary rock which contains kerogen, a solid mixture of organic compounds. Liquid hydrocarbons can be manufactured from kerogen. Kerogen is released as an oil-like liquid when oil shale is heated, a process known as retorting. Retorting can be performed ex situ in conjunction with mining operations and in situ in conjunction with underground heating operations.

As with bitumen, kerogen can be converted into SCO through thermal processes.

The Green River Formation, which includes parts of Colorado, Utah, and Wyoming is the source of the largest known oil shale deposits in the world. It estimated that the resources in place in the Green River Formation are 1.5 to 1.8 trillion barrels of oil (Reference 9). While oil shale recovery in the U.S. has not been considered profitable, the rise of crude oil prices in the last decade has led to renewed interest. A study by the Rand Corporation found that a first-of-a-kind retorting complex would be profitable with real crude prices at $70-$95 a barrel (2005 dollars). Shell Oil Company, however, is investing in large scale underground heating and in-situ extraction in the U.S. It has estimated that this process will be profitable in the mid-20s in term of dollars per barrel (Reference 9).

***Interest Level**: High* – The recovery of oil involves multiple processes that requires heat and energy at ideals levels for the HTGR technology. The application of highest interest is bitumen extraction and upgrading in Alberta's oil sands because of high demand, high growth, and the need for high temperature and pressure steam.

Coal and Natural Gas Derivatives

Gasification

Gasification is a process for converting carbonaceous materials to synthesis gas, typically a mixture of H_2 and CO gases (Reference 10). Gasification technologies are based on a number of different processes, listed in Table 2-5, which involve the reaction of carbon with air, oxygen, steam, carbon dioxide, or a mixture of these gases, at temperatures above 700°C (Reference 10).

The heat required for the reactions is generally supplied within the gasifier reactor through partial-oxidation of feedstock (e.g., combustion with 20% to 70% of the stoichiometric oxygen required for complete combustion) (Reference 10). Consequently coal gasifiers would require a re-design in order to completely integrate HTGR technology. General Atomics investigated the integration of HTGR technology with a catalytic coal gasification process without such a re-design (Reference 11). The HTGR was to supply all the energy requirements (steam, heat and electricity) of the gasification process except for those at very high temperature which would be provided by the gasification reaction. Two 600 MWt HTGR modules would provide this energy necessary for the processing of 13,144 tonnes of coal and production of 179 MMBtu/min of syngas per stream day (Reference 11).

In 2005, the U.S. syngas production capacity was 380 MMBtu/min thermal-equivalent (15% share of the world total) from 20 gasification plants (Reference 12). Of the 20 gasification plants, 7 use a coal feedstock, 4 use a petroleum feedstock, and 9 use a natural gas feedstock (Reference 12). Biomass is used as a feedstock in a small amount of gasifiers outside the U.S. There are, however, no plans for future development of biomass gasifiers (Reference 13). The syngas is used to produce power, fertilizers, various chemicals, and syngas for resale (Reference 10). By 2010, the syngas capacity in the U.S. is predicted to increase 8% to 410 MMBtu/min thermal (Reference 12). Key players in the gasification market are Shell, GE, ConocoPhilips, Chevron and the Dakota Gasification Company (which operates the Great Plains Synfuel Plant and has produced 90% of the syngas produced from coal in the U.S. to date) (References 13 and 14). Future gasifiers are considered a good group to utilize process heat from the next generation nuclear reactor because of the strong growth potential for gasifiers and the high process temperature used.

Indirect Coal to Liquids

Indirect coal to liquids (ICTL) takes syngas from a gasification process, removes sulfur and other contaminants, and runs it through a Fischer-Tropsch (F-T) process to obtain various products such as: paraffins, olefinic hydrocarbons or alcohols (particularly methanol). Typical low-temperature F-T processes are carried out using an iron based catalyst at 200°C to 250°C and 290 psi to 450 psi (References 15 and 16) Typical High Temperature F-T processes are carried out using iron based catalysts at 300°C to 350°C and 290 psi to 450 psi (References 15 and 16). The distillate product yields (weight percent of liquid derived from weight of coal feedstock) from ICTL are typically on the order of 30 weight percent (Reference 17).

General Atomics investigated the integration of HTGR technology with two ICTL processes, the SRC-II and H-Coal processes (Reference 11). The HTGR supplies all the energy needed (steam, heat and electricity) except for that supplied by the gasification reaction. For SRC-II process, two 600 MWt HTGR modules would provide this energy necessary for the production of 403 million scf of CH_4 and 175,000 bbls-equivalent of liquid fuels per stream day. For the H-Coal process, two 600 MWt HTGR modules could produce 121 MMBtu of fuel gas and 81,000 bbls of syncrude per stream day.

In 2004, 36% of the capacity of the world's gasifiers went into producing F-T liquids.

Direct Coal to Liquids

Direct coal to liquids (DCTL) is a process of converting coal to liquid and gaseous feedstocks. Many different processes have been developed for DCTL, but most processes involve the dissolution of a high proportion of coal in a solvent at elevated temperature and pressure, followed by the hydro-cracking of the dissolved coal with H_2 and a catalyst. Typical operating conditions for DCTL processes are between 350°C and 500°C at 1,400 psi to 4,300 psi (References 16 and 17). The distillate product yields (weight percent of liquid derived from coal feedstock) from DCTL are on the order of 40 weight percent (Reference 17).

DCTL technology was first used commercially in Germany in the 1930's during World War II. The US began to fund research in DCTL technologies from the 1970's to the early1990's. By the mid 1990's interest in DCTL in the US all but disappeared as interest in ICTL gradually increased due to the very low sulfur content and very high cetane of F-T diesel (Reference 17). Consequently, DCTL processes are not considered good candidates for process heat from next generation reactors.

Steam Methane Reforming

Steam methane reforming (SMR) is a large industrial process used to generate hydrogen. In steam reforming, a gaseous feed (typically methane) is injected into a heated reactor vessel (typically externally heated) where steam and the feedstock react to form syngas (References 15 and 18). A catalytic shift reaction and purifications steps are then performed to yield a hydrogen rich product stream (Reference 18). Steam reforming is very similar to gasification, but it is generally not considered a gasification process (Reference 15). Steam reforming is typically performed with a low sulfur feedstock and a nickel catalyst at temperatures between 500°C and 950°C and at pressures of around 440 psi (Reference 18).

The steam reforming industry is large, using up to 5% of the natural gas in the U.S. (Reference 19).

Interest Level*: High* - The production of syngas from gasification, hydrogen from SMR, and synthetic products of the F-T process all employ processes that require energy at temperatures that match well with HTGR technology. The demand for hydrogen and syngas is forecasted to grow substantially. Existing gasification reactors that rely on oxidation of fuel will not be directly convertible to nuclear process heat source and further development of appropriate components will be required. Other countries, such as Germany and Japan, are also working on how to apply nuclear process heat to these gasification processes. The application of HTGR technology to SMR requires less technology development.

2.3.2 Chemicals

Petrochemicals

Petrochemicals include basic organic chemicals, such as ethylene, propylene, benzene, and xylene. These chemicals are produced using the cracking processes described in Table 2-3.

Additional chemicals are derived from these basic organic chemicals. Most of these chemicals have process temperatures below 300˚C, but a few, such as Styrene and Acrylonitrile, have process temperatures between 400˚C and 700˚C.

Table 2-6 lists some of the most commonly produced chemicals in the U.S. and includes the temperatures of their respective production processes. Basic organic chemicals and their derivatives are included. These chemicals are near the top in terms of production in the U.S. Table 2-7 lists the top chemical companies in the world. Large, diversified chemical companies such as Dow Chemical, Dupont, Lyondell, Chevron Phillips, and Huntsman are top producers of petrochemicals.

***Interest Level**: High* – Approximately half of the top 30 chemicals produced in the U.S. are petrochemicals. Their production involves processes which require high temperatures and high amounts of process energy.

Industrial Gases

Industrial gases are inorganic gases that include nitrogen, oxygen, hydrogen, and carbon dioxide. They are listed in Table 2-6. Hydrogen and carbon dioxide are produced by steam reforming between 500˚C and 950˚C. Praxair and Air Products are two of the top producers of industrial gases in the U.S. Refiners such as Chevron and BP are also top producers of hydrogen in the U.S.

There is also ongoing research into high temperature hydrogen production processes. Three of interest are high temperature electrolysis (HTE), the sulfur-iodine (SI) process and the hybrid sulfur (HyS) process. Each of these processes achieves high energy efficiencies at 850-950˚C.

***Interest Level**: High* - The production of hydrogen and carbon dioxide involves steam reforming, which is performed at temperatures that match HTGR technology. Future hydrogen production processes, such as electrolysis, the SI process, and the HyS process, are also performed at temperatures that match HTGR technology.

Fertilizers

Table 2-6 lists other significant inorganic chemicals. Ammonia, which is produced using the Haber Process between 400˚C and 600˚C, is an important inorganic chemical because of its extensive use in direct application fertilizers. CF Industries Holdings, Inc., PCS Nitrogen and Terra Industries Inc. are three of the top fertilizer producers in North America.

***Interest Level**: High* - The production of hydrogen and ammonia are central to the production of nitrogenous fertilizers. Both are processed at temperatures that match HTGR technology.

Polymer Products

Synthetic Rubber

The demand for rubber in the U.S. was 3.71 million metric tons in 2000. 34% of this rubber was natural, with the remainder being synthetic (Reference 20). Both natural and synthetic rubbers are processed at relatively low temperatures. The vulcanization of natural rubber occurs at 100-160˚C (Reference 21), while polymerization of synthetic rubbers occurs mainly at lower temperatures.

Plastics

The U.S. production of plastics is above 70 billion pounds/year. Process temperatures for plastics are higher than for rubbers, though they remain relatively low (<200˚C). An exception is Low-Density Polyethylene (LDPE), for which a temperature in the range of 300-500˚C is required. LDPE is included in Table 2-6. LDPE accounted for 7.6 billion lbs of the 71.2 billion lbs of plastics produced in the U.S. in 2000 (Reference 21).

Organic Coatings and Adhesives

While paints, coatings, and adhesives have a high energy demand in the U.S., they do not require high temperature heat for their production.

Noncellulosic Organic Fibers

Noncellulosic organic fibers are made by polymerization and are completely synthetic. Nylon and polyester are two of the top selling types. Nylon 6 and Nylon 6,6 are produced at 280-300˚C while polyester is polymerized at 200-290˚C. These materials are included in Table 2-6. Nylon and polyester accounted for 2.6 and 3.9 billion lbs of the 10.3 billion lb synthetic fibers market (Reference 21).

As with petrochemical derivatives, the top producers of polymer products are the large, diversified chemical companies such as Dow Chemical, Dupont, Lyondell, and Huntsman.

***Interest Level**: Medium* - There is a tremendous demand for products made from polymers but they are generally produced at temperatures below 200˚C and would not well match HTGR technology. A small amount of popular plastics and fibers, however, are produced at higher temperatures.

Pharmaceuticals

The pharmaceutical industry is extremely large and well-developed in the U.S., and the preparation of pharmaceuticals consumed 84 TBtu in 2002. However, the 2002 Manufacturing Energy Consumption Survey reports that pharmaceutical preparation was taking place at 606 establishments (Reference 2). The high number of establishments and relatively low energy use indicates that the production processing at each site is relatively small (average of about 5 MW). Top U.S. pharmaceutical companies include Johnson & Johnson, Pfizer, and Merck.

***Interest Level**: Low* - The process heat needs of the pharmaceutical industry on a per manufacturer basis are relatively low. Therefore, the use of the HTGR technology does not fit well.

2.3.3 Paper

The pulp and paper production industry is very well developed in the United States. Sales totaled $156 billion in 1998 in comparison with $424 billion for the entire chemicals industry. There are about 200 pulp mills and 600 paper mills in the U.S (Reference 21). 57% of the industry made use of cogeneration technologies in 2002 (Reference 4). The typical energy requirement for one of these mills is 5 MW (Appendix A).

Most paper is made via the Kraft process. This involves the digestion of white liquor, an aqueous solution of sodium hydroxide and sodium sulfide, with steam at 170-175˚C for 2-5 hours (Reference 21). The resultant substance is termed black liquor, and pulp is filtered out. Some of the remaining components of the black liquor are useful products, but most of the liquor is burned to produce about half of the steam and electricity needed to support the entire production process (Reference 4). Most of the other steam needs are for low temperature uses such as evaporation and drying. Included in the production process is the calcination of lime, which typically occurs at 1200˚C via direct-fired heating (Reference 21).

Other forest products involving process heat are steam distillation for specialty oils and solvents and charcoal manufacture. Distillations are at relatively low steam temperatures (below 200°C) and therefore not of high interest. The production of charcoal is a high temperature pyrolysis process (up to 500°C) but uses the exothermic heat of the intermediate temperature burning-off of charcoal impurities and makes the products in small kilns, and mostly by small batch methods – both of which are not consistent with HTGR technology.

Top U.S. paper companies include International Paper, Weyerhauser, and Georgia-Pacific (owned by Koch Industries).

***Interest Level**: Low* - The total process heat and energy needs of paper manufacturers are relatively high, but the temperatures required are either on the low end of interest (<175˚C) or too high (1200˚C), and the (500°C) charcoal process takes place in small batches, so priority is low for HTGR technology. In addition, the typical energy requirement for a mill is very low and byproducts, having little value otherwise, are burned to provide half of the steam and electricity needs of paper producers.

2.3.4 Metals

The metals industry has a very high need for process energy and heat. It consumed 2,100 TBtu of energy as fuel in 2002 (Reference 2). Iron, steel, and aluminum account for the majority of metals production in the U.S. Metal producers do not typically employ cogeneration technologies.

The melting process accounts for 55% of the energy use in the production of primary metals. Heat treatment, which also requires process heat, accounts for only 6% (Reference 22). Table 2-8 provides details on various metals and includes their top producers. The melting temperatures of iron, steel and aluminum, and copper are above 960˚C. The melting temperature of zinc is 400˚C, but zinc accounts for only 1.5% of all U.S. metal production. Melting takes place in electrically heated or direct-fired furnaces. The typical electrical demand of these furnaces is 1-3 MW (Reference 22).

The production of steel traditionally begins with the reduction of iron ore (Fe_2O_3) with coke and limestone in a blast furnace. This process removes oxygen from the ore, leaving pig iron as a product. The pig iron is then converted into steel by oxidation of impurities and controlled addition of alloying elements.

The production of direct reduced iron (DRI) is an alternative to the formation of pig iron in a blast furnace. DRI is produced by the removal of oxygen from iron ore by a syngas, which provides a reducing environment at temperatures below the melting point of the ore. The gas temperature is in the range of 850-950˚C (Reference 23). Hot Briquetting Iron (HBI), a compacted form of DRI, is formed at temperatures of 650-700˚C (Reference 25). DRI can be transported or immediately fed into electric furnaces to minimize the energy needed for melting.

There are several DRI production processes. Midrex Technologies developed the MIDREX® process for producing DRI, which is used by 60% of the world's plants and uses natural gas. Other natural gas-based production processes include the HYL and Finmet processes, with market shares of 18% and 2%, respectively. Coal-based DRI production makes up the remaining 20% of production (Reference 24).

From 1970 to 2006, the world production of DRI increased from 0.79 to 59.9 million metric tons. DRI production in the U.S. is only 0.24 million metric tons (Reference 24). Mexico, however, is a relatively large producer at 6.17 million metric tons.

Metal production requires large quantities of steam and electricity, therefore providing an opportunity for an HTGR to serve as a cogeneration plant. General Atomics investigated specific cogeneration applications to the production of steel and alumina (Reference 11). An HTGR that provides 295 MWt and 240 MWe could support production of 6.5 million tonnes of steel using steam at
385 ˚C and 4.95 MPa. An HTGR that provides 317 MWt and 544 MWe could support production of 726 thousand tonnes of alumina using steam at 320 ˚C and 5.0 MPa.

***Interest Level**: High* - The production of DRI and HBI employs processes that require heat at temperatures that match HTGR technology. While global growth is strong, production in the U.S. is very low. The Japanese HTGR development program considers the production of DRI to be one of the three key, potential applications of the HTGR technology (Reference 26). In addition, the production of DRI and the subsequent melting of iron in electric furnaces provides a potential cogeneration application for the HTGR technology. DRI is currently produced via gasification processes, therefore integrating the HTGR plant with the production of DRI would require significant technology development.

2.3.5 Nonmetallic Mineral Products

Glass

The glass industry is a well developed industry in the United States. 20 million metric tons were produced and $28 billion worth of glass were sold in 1999 (Reference 27). Growth is stable, usually following the Gross Domestic Product. The glass manufacturing process is very similar irrespective of the type of glass being produced. Table 2-9 describes each step in this process and provides the temperatures at which they take place in addition to the energy source. The temperatures required for the melting and refining of glass are near 1500˚C. These temperatures are reached by burning natural gas or by electric heating. Though its energy requirements are large, the industry does not employ the use of cogeneration technologies. Top U.S. manufacturers of glass include PPG Industries and Owens-Corning.

Interest Level*: Low* - The production of glass employs processes that require temperatures that are much higher than the capabilities of the HTGR technology.

Cement

As of 2001, there were 118 cement manufacturing facilities in the United States with a total of 192 cement kilns operating. 89 million tonnes of cement were produced in 2001. Of the 550 TBtu of energy consumed by the cement industry in 2000, 74% of it was used in the pyroprocessing, or calcination, step that takes place in large rotary kilns at 1500 ˚C. This temperature is reached primarily via the firing of coal and petroleum coke, though some petroleum and natural gas is fired as well (Reference 28). The use of a catalyst to lower the calcination temperature to ~800˚C is possible (Reference 29) though is not employed in any of today's cement plants. Little research and development is being undertaken in this area as well. Top U.S. manufacturers of cement include Lehigh Cement Company and Ash Grove.

Interest Level*: Medium* - The production of cement currently employs process temperatures that are much higher than the capabilities of the HTGR technology, but production is possible in the future at lower temperatures. Significant technology development will be required to apply new production methods.

Table 2-3. Process Temperatures of Petroleum Refining Processes (Reference 3)

Process	Description	Subcategories	Process Temp (˚C)
Distillation	Separation of crude oil into groups of hydrocarbon based on molecular size and boiling point ranges	Atmospheric	400
		Vacuum	400-500
Thermal Cracking	Use of heat and pressure to breakdown, rearrange, and combine hydrocarbon molecules	Delayed Coking	500
		Flexi-coking	500-950
		Fluid Coking	500-550
		Visbreaking	400-500
Catalytic Cracking	Braking down of heavier, and more complex hydrocarbon molecules into simpler and lighter molecules using heat and a catalyst		480-815
Catalytic Hydro cracking	Use of hydrogen and catalysts on middle boiling point hydrocarbons		290-400
Hydro treating	Treatment of petroleum in the presence of catalysis and hydrogen		<427
Catalytic Reforming	Conversion of low-octane napthas into high-octane gasoline blending components		500-525

Table 2-4. Top 20 U.S. Refiners (Reference 3)

Refiner	2005 Capacity (Million Barrels per Calendar Day)
ConocoPhillips	2198
ExxonMobil	1847
BP	1505
Valero Energy	1450
Chevron Texaco	1007
Marathon Oil	948
Sunoco	900
Premcor	768
Koch	763
Motiva Enterprises	747
PDV America	719
Royal Dutch Shell	597
Tesoro	563
Deer Park REFG Ltd.	334
Lyondell Chemical	270
Total SA	234
Chalmette Refining	187
Sinclair Oil	161
Rosemore	155
Murphy Oil	153

Table 2-5. Production Process Temperatures for Coal and Natural Gas Derivatives (References 10, 15, 16, and 17)

Process	Description	Sub Categories	Existing Process Temp (˚C)
Pyrolysis	Chemical decomposition induced in organic materials by heat in the absence of oxygen	Carbonization	400
		Conventional	600
		Ultra	1000
Gasification	Convert carbon feedstock into syngas by reacting carbon with air or oxygen and steam	Moving Bed	420-650[1]
		Fluidized Bed	920-1050
		Entrained Bed	1200
Fischer-Tropsch	Catalyzed chemical reaction that converts syngas into liquid hydrocabons of various forms	Low Temperature	200-250
		High Temperature	300-350
Steam Methane Reforming	Steam and methane react at elevated temperatures to form syngas. A catalytic shift reaction and purification process increase the hydrogen content of the product.		500-950
Direct Coal to Liquids	Direct conversion of coal to liquid feedstocks through dissolution of coal in a solvent at elevated temperatures and pressures folowed by hydro-cracking of the dissolved coal with H2 and a catalyst	Single Stage	320-500
		Double Stage	400-450

Note 1: Gasification reactions proceed at practical production rates above 700°C.

Table 2-6. Process Temperatures and Annual Production in the U.S. Chemical Industry (Reference 21)

	Chemical	Process (if readily available)	Process Temp (˚C)	Billions of lb (2002)
Petrochemicals (Basic Organic Chemicals)	Ethylene	Steam Cracking	815-870	58.01
	Propylene	Steam Cracking	815-870	30.27
	Butadiene	Steam Cracking	815-870	4.45
	Isobutylene	Steam Cracking	815-870	3.68
	Benzene	Catalytic Reforming	450-510	18.36
	Toluene	Catalytic Reforming	450-510	7.63
	p-Xylene	Catalytic Reforming	450-510	6.86
Petrochemicals (Organic Chemical Derivatives)	Formaldehyde	Oxidation or Dehydrogenation	450-900	9.69
	Styrene	Dehydrogenation of Ethylbenzene	630	12.37
	Acetone	Rearrangement of Cumene Hydroperoxide	110-500[2]	3.16
	Acrylonitrile	Ammoxidation	400-450	3.56
	Ethylbenzene	Friedel-Crafts Alkylation	90-420[2]	13.63
	Ethylene Oxide	Air Epoxidation	270-290	9.24
	Acetic Acid	Multiple	50-250[2]	6.71
	Cumene	Friedel-Crafts Alkylation	175-225	7.25
	Cyclohexane	Transformation of Benzene	210	2.97
	Terephthalic Acid	Amoco Process	200	9.06
	Vinyl Acetate	Vapor-phase Reaction	175-200	2.8
	Ethylene Glycol	Hydration and Ring Opening	50-195[2]	7.5
	Butyraldehde	Oxo Process	130-175	3.06
	Adipic Acid	Air Oxidation	50-160[2]	2.2
	Bisphenol A	Phenol with Acetone	50	2.3
	Ethylene Dichloride		40-50	23.75
	Phenol	Rearrangement of Cumene Hydroperoxide	30	5.19
Industrial Gases	Hydrogen	Steam Methane Reforming	500-980	Note 4
	Carbon Dioxide	Steam Methane Reforming	500-980	12.41
	Nitrogen	Air Liquefaction	Very Low	77.57
	Oxygen	Air Liquefaction	Very Low	60.97

Table 2-6. (Continued)

	Chemical	Process (if readily available)	Process Temp (˚C)	Billions of lb (2002)
Other Inorganic Chemicals	Titanium Dioxide		1200-1400	3.22
	Carbon Black	Combustion/Thermal Cracking	1200-1400	3.95
	Sodium silicate	Soda ash heated with sand	1200-1400	Note 3
	Sulfuric Acid	Contact Process (99%)	1000	90.77
	Nitric Acid		750-920	18.3
	Ammonia	Haber Process	400-600	34.43
	Urea		190	18.53
	Soda Ash		175	Note 3
	Ammonium Nitrate	Vacuum Evaporation	125-140	17.15
	Aluminum Sulfate		105-110	2.22
	Phosphoric Acid	Wet Process (90%)	75 - 80	26.82
	Caustic Soda	Electrolysis of Brine	Note 3	Note 3
	Chlorine	Electrolysis of Brine	Note 3	27.51
Plastics	Low-Density Polyethylene		300-500	7.6
Synthetic Fibers	Nylon 6 and Nylon 6,6		280-300	2.6
	Polyester		200-290	3.9

Note 1: Table is organized by industrial category and the chemicals are listed in descending order according to their process temperatures.

Note 2: Large temperature range is presented because the catalyst used can vary.

Note 3: Information not available from source.

Note 4: Hydrogen production is difficult to quantify because most of it is not sold but rather used as feed for one process at the same refinery where it was produced in another process. The total annual U.S. demand was estimated at 9 million tons in 2005 (Reference 35). U.S. merchant production, that which was produced for sale as an industrial gas, was 1.05 trillion standard cubic feet (scf) in 2007 (Reference 33), or about 3 million tons.

Table 2-7. World's Largest Chemical Companies (Reference 30)

Rank	Company	Chemical Sales ($ MILLIONS) 2006	Chemical Sales as % of Total Sales	Headquarters Country
1	BASF	$49,516	75	Germany
2	Dow Chemical	$49,124	100	U.S.
3	Royal Dutch Shell	$36,306	11	U.K./Netherlands
4	ExxonMobil	$34,098	9	U.S.
5	Ineos Group	$33,366	100	U.K.
6	DuPont	$28,928	100	U.S.
7	China Petroleum & Chemical	$27,783	21	China
8	Total	$24,012	12	France
9	Formosa Plastics Group	$21,012	60	Taiwan
10	Bayer	$19,926	55	Germany
11	SABIC	$19,749	86	Saudi Arabia
12	Lyondell	$19,507	88	U.S.
13	Mitsubishi Chemical	$18,671	83	Japan
14	Mitsui	$14,513	100	Japan
15	Degussa	$13,718	100	Germany
16	Basell	$13,185	100	Netherlands
17	Akzo Nobel	$12,586	73	Netherlands
18	Sumitomo	$12,112	79	Japan
19	Air Liquide	$12,096	88	France
20	Chevron Phillips	$11,839	100	U.S.
21	Toray	$11,668	88	Japan
22	Shin-Etsu	$11,217	100	Japan
23	Huntsman	$10,624	100	U.S.
24	DSM	$10,528	100	Netherlands
25	Petrochina	$9,386	11	China

Table 2-7. (Continued)

Rank	Company	Chemical Sales ($ MILLIONS) 2006	Chemical Sales as % of Total Sales	Headquarters Country
26	LG Chem	$9,344	72	South Korea
27	Reliance	$9,344	40	India
28	Solvay	$9,280	79	Belgium
29	ICI	$8,931	100	U.K.
30	PPG Industries	$8,808	80	U.S.
31	Dainippon	$8,732	100	Japan
32	Lanxess	$8,724	100	Germany
33	ENI	$8,572	8	Italy
34	Asahi Kasei	$8,521	61	Japan
35	Praxair	$8,324	100	U.S.
36	Linde	$7,783	50	Germany
37	Air Products	$7,743	87	U.S.
38	Yara	$7,530	100	Norway
39	Eastman	$7,450	100	U.S.
40	Rohm and Hass	$7,401	90	U.S.
41	Arkema	$7,369	100	France
42	Borealis	$7,214	100	Austria
43	Sasol	$6,783	56	South Africa
44	GE	$6,673	4	U.S.
45	Celanese	$6,656	100	U.S.
46	Nova	$6,519	100	Canada
47	Clariant	$6,463	100	Switzerland
48	Syngenta	$6,380	79	Switzerland
49	Rhodia	$6,043	100	France
50	Braskem	$5,977	100	Brazil

Table 2-8. Metal Smelting

Metal Category	Energy Use as Fuel, 2002 (TBtu) (Ref. 2)	Metal	Typical Melting Energy Source	Melting Temp (˚C)	Top North American Producers
Ferrous Metals	1455	Iron and Steels	Electricity, coal, natural gas	1600	U.S. Steel Group, Nucor Group, AK Steel
Aluminum	351	Primary Aluminum	Electricity	960	Alcoa Group, Alcan Group
Other Nonferrous	95	Copper	Electricity	1100	Asarco
		Zinc	Electricity	400	HudBay Minerals

Table 2-9. Temperatures used for Glass Manufacturing (Reference 27)

Step	Description	Energy Source	Process Temp (˚C)
Batch Preparation	Blending of raw materials	Electricity	-
Melting	-	Natural Gas, electricity, or combination	1500
Refining	Frees bubbles, homogenizes, and heat conditions	Natural Gas, electricity, or combination	1550
Forming	Shape glass	Electricity	800-1100

3 Preliminary Survey

3.1 Technology Development Needs

As noted in the screening assessment, the application of HTGR technology to some processes will require significant technology development. These will be termed "far-term" applications. Other applications, however, will not require significant technology development. These will be termed "near-term" applications.

Near-term applications are currently in use on an industrial scale and can incorporate HTGR process energy without significant technology development. These include petroleum refining, bitumen extraction and upgrading, petrochemicals, polymer products, steam methane reforming, and nitrogenous fertilizers. For far-term applications, production methods are either in use today in a form that is different from the potential process that uses HTGR process energy or they are not currently in use on an industrial scale. Gasification, the integration of CTL technologies, the production of DRI, and cement manufacturing all exist today on an industrial scale but cannot be integrated with an HTGR without significant manufacturing engineering technology development. High temperature hydrogen production methods (e.g., water splitting) are still in the development phase and will require more technology development to determine the practicality of industrial scale applications.

3.2 Energy Requirements

Analysis of energy requirements was performed on near-term applications. The energy requirements of the selected processes and products were analyzed, and if possible, the estimated demand for individual process plants was estimated. A survey of the companies engaging in these production methods will ultimately serve to augment and clarify this analysis.

The following assumptions apply to the analysis below:

- The energy requirement for steam depends on the plant feedwater temperature and the pressure and temperature of the steam itself. A value of 1200 Btu/lb is assumed.
- An energy of 23,000 Btu/lb and 1030 Btu/cf is assumed for natural gas.
- An efficiency of 33% is assumed for the generation of electricity.

The production levels and production energies of near-term applications were analyzed. Where possible, energy use was divided into steam, electricity, and fuel demands. In addition, the energy demand for individual process plants was estimated in cases where applicable data could be acquired. A survey of the companies engaging in these production methods will ultimately serve to augment and clarify these calculations.

3.2.1 Petroleum Refining

Table 3-1 details the energy demands of the primary petroleum refining processes provided in Table 2-3. The 2005 capacity of North America is also included in the table to estimate the relative energy demands of each process. While steam and electricity demands were significant, fuel demand was much greater. With respect to the specific processes, catalytic hydrocracking, hydrotreating, and catalytic reforming were the most energy intensive on a production energy basis.

The energy demands of a single petroleum refinery vary greatly depending on the distillation capacity of the refinery and the type and amount of downstream processing that takes place in that refinery. 158 refineries were operating in North America in 2005. Table 3-2 shows that the average refinery demand was 643 MWt total. Larger, complex refineries that have production capacities of 100,000 – 500,000 bpd and catalytic cracking, hydrocracking, reforming, and hydrotreating capabilities demand much greater amounts of energy, as shown in Table 3-3.

3.2.2 Bitumen extraction and upgrading

Table 3-4 provides the energy requirements for ex-situ extraction (mining), in-situ extraction, and upgrading. The fuel demand in the table includes the fuel burned to generate steam. The table shows that ex-situ extraction requires the most fuel per barrel (primarily for the generation of steam). Very little electricity, however, is required. The 2006 production is also provided in

Table 3-4 to provide a calculation of the total yearly energy demands.

As of the end of 2006, most of the oil sands projects in Alberta had individual production capabilities in the range of 10,000 – 50,000 bpd of bitumen. The majority of these projects have expansion plans to ultimately produce 100,000 to 500,000 bpd of bitumen in the 2010-2016 timeframe (Reference 6). Table 3-5 provides the plant sizes for 100,000 bpd of ex-situ mining, in-situ extraction, and upgrading. For ex-situ extraction, a value of 1270 MWt is estimated. This plant size is on the same order as the value of 1000 MWt discussed with Westinghouse/PBMR (Appendix B).

3.2.3 Petrochemicals and Polymer Products

Table 3-6 provides the production values and process energies for the petrochemical and polymer products whose manufacture requires high temperature steam and heat. Steam cracking to produce ethylene and the dehydrogenation of ethylbenzene to produce styrene are the processes that demand the most total energy based on production and process energy.

3.2.4 Steam Methane Reforming

Table 3-7 provides the energy requirements for the production of 57 million scfd of hydrogen via SMR. An HTGR cannot replace the feedstock and could only replace the steam, fuel, and electricity. Therefore, the process energy that an HTGR could replace would be 106 Btu/scf. These values were calculated based on a single reference plant that was analyzed in Reference 32. In this plant, natural gas used as fuel is 10% of the total natural gas used. Other sources indicate that this percentage can be closer to 20% in other plants.

Table 3-8 extrapolates the data in Table 3-7 to a theoretical 100 million scfd H_2 SMR production plant (a typical plant production value). The total thermal demand that an HTGR can replace is 130 MWt.

U.S. merchant hydrogen production was 1.05 trillion standard cubic feet (scf) in 2007 (Reference 33). Approximately 95% of all hydrogen produced by merchant plants is done so via SMR. Therefore, the total annual expended energy for merchant plant hydrogen production via SMR applicable to HTGR technology is 106 TBtu.

3.2.5 Nitrogenous Fertilizers

Table 3-9 provides the production values and process energies for nitrogenous fertilizer chemicals. The production of ammonia was the most significant energy demand for this category.

Table 3-1. Charge Capacity and Energy Demand for Refining Processes in North America, 2005 (Reference 3)

Process	Production	Steam	Electricity	Fuel	Total Energy
	Thous BPCD[1]	lb/bbl	kWh/bbl	MMBtu/bbl	MMBtu/year
Atm. Distillation	20627	10	0.9	0.05	5.36E+08
Vacuum Distillation	9106	10	0.3	0.03	1.50E+08
Coking[2]	143616	700	30	3.46	2.42E+08
Catalytic Cracking	6574	-30[4]	6	0.1	3.01E+08
Cat. Hydrocracking[3]	1738	75	13	0.2	2.68E+08
Hydrotreating[3]	15146	8	3	0.15	1.05E+09
Cat. Reforming	4173	30	3	0.3	5.59E+08
Total					**3.11E+09**

Note 1: BPCD = Barrels Per Calendar Day
Note 2: Coking capacity is described in tons per calendar day. Likewise, coking production energies are described on a per ton basis.
Note 3: With catalytical hydrocracking and hydrotreating, production energies can vary significantly, depending on the specific process. A median value was used based on those provided in Reference 3.
Note 4: Catalytic cracking produces excess amounts of steam. Therefore, it has a negative steam requirement.

Table 3-2. Average Energy Demand for North American Refineries (Reference 3)

Process	Energy Demand Per Refinery (MWt)			
	Steam	**Electricity**	**Fuel**	**Total**
Atm. Distillation	19	14	78	111
Vacuum Distillation	8	2	21	31
Coking	9	3	38	50
Catalytic Cracking	-18	30	50	62
Cat. Hydrocracking	12	17	26	55
Hydrotreating	11	35	171	217
Cat. Reforming	11	10	94	115
Total	**52**	**111**	**478**	**641**

Table 3-3. Energy Demands of Two Complex, Large Scale Refineries (Reference 3)

	Process	Capacity (BPCD)	Energy Demand (MWt)			
			Steam	**Electricity**	**Fuel**	**Total**
Exxon Baton Rouge	**Atm. Distillation**	5.01E+05	73	56	306	435
	Vacuum Distillation	2.27E+05	33	9	83	125
	Coking	1.13E+05	12	4	192	208
	Catalytic Cracking	2.29E+05	-101	172	280	351
	Cat. Hydrocracking	7.55E+04	26	39	59	124
	Hydrotreating	2.40E+04	39	125	611	775
	Cat. Reforming	3.34E+05	33	28	277	338
	Total		**115**	**433**	**1808**	**2356**
Exxon Chalmette	**Atm. Distillation**	1.88E+05	28	21	115	164
	Vacuum Distillation	1.12E+05	16	4	41	61
	Coking	3.30E+04	3	1	56	60
	Catalytic Cracking	6.80E+04	-30	51	83	104
	Cat. Hydrocracking	4.70E+04	21	31	46	98
	Hydrotreating	1.85E+04	20	65	316	401
	Cat. Reforming	1.73E+05	21	18	172	211
	Total		**79**	**191**	**829**	**1099**

Table 3-4. Oil Sands Production and Energy Usage, 2006 (References 6 and 31)

Process	Production	Natural Gas	Electricity	Total
	BPD	cf/bbl	kWh/bbl	MMBtu/year
Mining	7.61E+05	250	30	1.57E+08
In-situ Extraction	4.62E+05	1000	1	1.76E+08
Upgrading (low)	6.60E+05	40	14	4.45E+07
Upgrading (high)	6.60E+05	300	55	2.10E+08

Table 3-5. Energy Demands for a 100,000 BPD Oil Sands Plant

Process	Natural Gas (MWt)	Electricity (MWt)	Total (MWt)
Mining	314	375	689
In-situ Extraction	1258	13	1271
Upgrading (low)	50	175	225
Upgrading (high)	377	688	1065

Table 3-6. Process Energies of Petrochemicals and Polymer Products (Refs 21 and 34)

	Product	Production, 2002	Process Energy	Energy
		billion lbs	Btu/lb	MMBtu/year
Basic Organic Chemicals	Ethylene	5.80E+01	2877	1.67E+08
	Propylene	3.03E+01	1856	5.62E+07
	Benzene	1.84E+01	2000[1]	3.67E+07
	Toluene	7.63E+00	1192	9.09E+06
	p-Xylene	6.86E+00	1192	8.18E+06
Organic Chemical Derivatives	Styrene	1.24E+01	16891	2.09E+08
	Acetone	3.16E+00	8664	2.74E+07
	Acrylonitrile	3.56E+00	1313	4.67E+06
	Ethylbenzene	1.36E+01	1261	1.72E+07
	Ethylene Oxide	9.24E+00	2736	2.53E+07
	Cumene	7.25E+00	-395	-2.86E+06
	Cyclohexane	2.97E+00	638	1.89E+06
	Terephthalic Acid	9.06E+00	3066	2.78E+07
Polymers	Low-Density Polyethylene	7.60E+00	1620	1.23E+07
	Nylon	2.60E+00	19299	5.02E+07
	Polyester	3.90E+00	14480	5.65E+07

Note 1: Benzene is produced via catalytic reforming and also the hydrodealkylation of toluene. Based on the energies involved in these processes, 2000 Btu/lb is estimated as a process energy for benzene.

Table 3-7. Process Energy Calculation from Sample SMR Plant Energy Demands (Reference 32)

Production Capacity	Steam		Natural Gas		Electricity	Process Energy
	Required	Produced	Feed	Fuel	Required	
million scfd	MMBtu/day					Btu/scf
57	3.42E+03	4.92E+03	1.99E+04	2.19E+03	4.36E+02	106

Table 3-8. Thermal Energy Demands for a 100 million scfd H_2 SMR Plant

Steam (MWt)	Natural Gas (MWt)	Electricity (MWt)	Total (MWt)
Required	Fuel	Required	
72	47	9	128

Table 3-9. Process Energies of Nitrogenous Fertilizer Chemicals (References 21 and 34)

Product	Production, 2002	Production Energy	Total Energy
	billion lbs	Btu/lb product	MMBtu
Ammonia	34.43	14058.0	4.84E+08
Nitric Acid	18.30	-306.0	-5.60E+06
Ammonium sulphate	5.97	5495.0	3.28E+07
Urea	18.53	951.0	1.76E+07
Ammonium nitrate	17.15	592.0	1.02E+07

3.3 Total Energy Demand

Figure 3-1 shows the energy demand for present applications with respect to their process temperatures. Most of these applications require temperatures below 700˚C. SMR and steam cracking to produce ethylene and propylene are the highest temperature applications shown in Figure 3-1. The energy required for the petroleum refining processes in Table 3-1 includes all North American refineries and is a representation of capacity rather than production. This value is corrected by a factor of 80% to produce an equivalent U.S. energy requirement and provide for a more appropriate comparison.

The amount of 500 MWt HTGR modules required to meet these energy demands (assuming 85% capacity) is shown in Figure 3-2.

The in-situ recovery of bitumen from Oil Sands shows the highest potential for growth in North America. The Canadian Association of Petroleum Producers expects extraction of bitumen via in-situ methods to reach 1.7 million bpd by 2020 (Reference 8). This represents a 270% increase from 2006 production levels. The annual energy demand for this application will increase accordingly to 645 TBtu. This equates to fifty 500 MWt HTGR modules running at 85% capacity.

Based on the energy demands in Figure 3-1, an estimate for the amount of CO_2 that is emitted from the production of this energy was calculated.

The majority of the process energy was generated using natural gas, which emits approximately 120 lbs of CO_2 per MMBTU. Coal and other fuels were also burned to produce this energy. Nearly all of these fuels, including coal (~210 lb CO_2/MMBTU), emit more CO_2 than natural gas. To generate a lower bound estimate, 120 lbs of CO_2 per MMBTU was assumed for the calculation of CO_2 emissions.

The annual CO_2 emissions from near-term applications in the U.S. are shown in Figure 3-3.

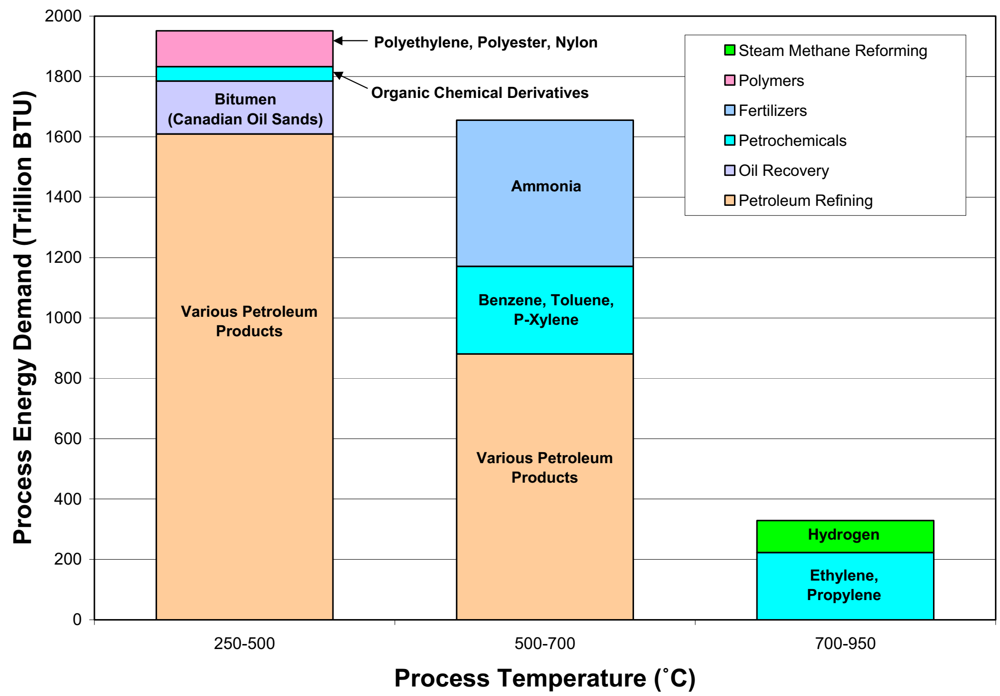

Figure 3-1. Near-term HTGR Application Annual U.S. Energy Demand vs. Temperature (2000-2007)

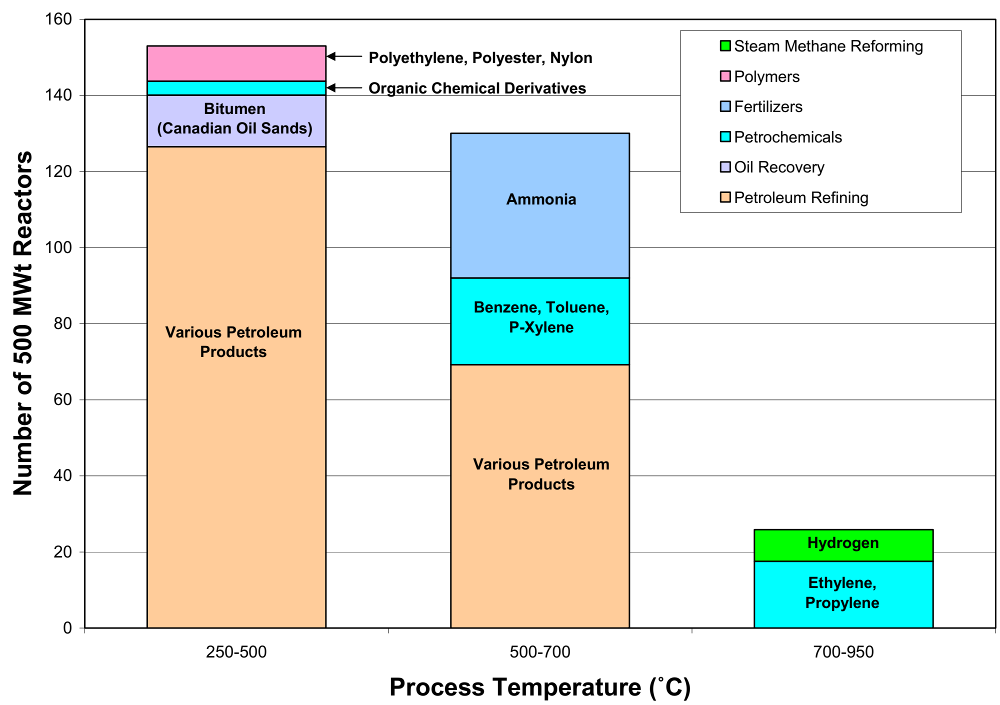

Figure 3-2. Number of 500 MWt HTGR Modules at 85% Capacity Required to Meet Demands (2000-2007)

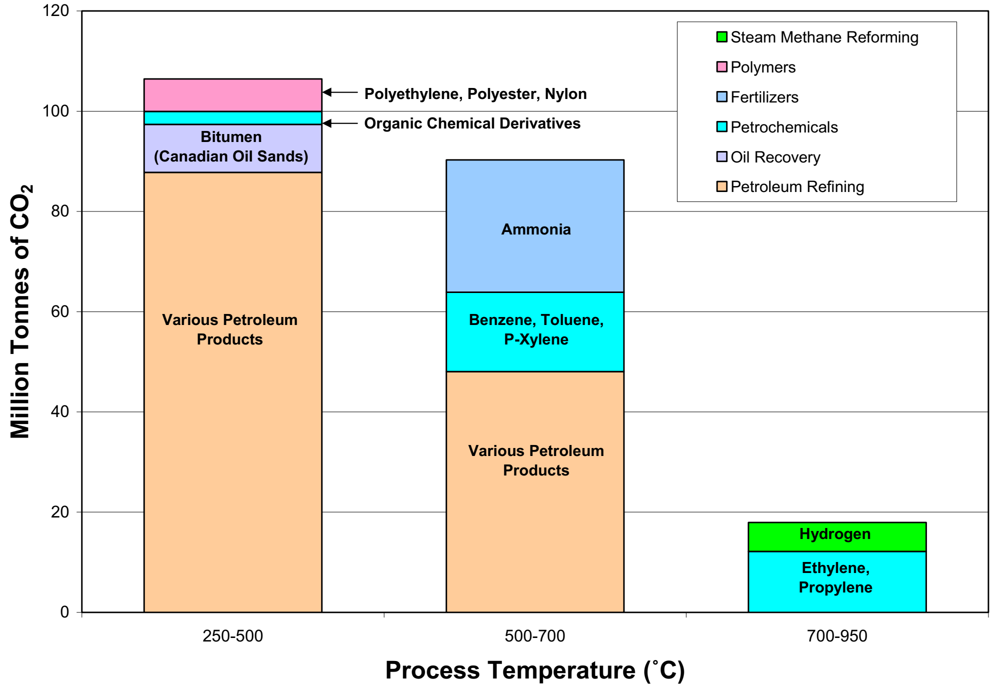

Figure 3-3. Potentially Avoidable Annual U.S. CO_2 Emissions from Near-term Applications (2000-2007)

3.4 COGENERATION

The combined generation of heat and electricity (cogeneration) is sometimes utilized in a process heat plant because electricity is needed as part of general plant support or for the production methods (e.g. electrolysis). In other situations, the capacity of the process heat plant is designed larger than needed for the processes initially supported by the industrial plant site and electricity can be sold back to the grid until future local needs increase.

Cogeneration is employed in each of the industrial sectors identified in Section 3. Figure 3-4 shows the number of establishments that employed cogeneration technologies in 2002. Only three of these sectors, petroleum refining, petrochemicals, and fertilizers, had more than 5% of their plants employ cogeneration technologies in 2002. The total number of establishments is compared to the number of cogenerating establishments for these sectors in Figure 3-5.

Figure 3-6 and Figure 3-7 display the purchases of electricity and steam. The purchases are broken down into those from a local utility and those not from a local utility. A local utility is defined as "an entity that produces and/or delivers a particular energy source and is legally obligated to provide service to general public within its franchise area. Sources other than a local utility include independent producers, brokers, marketers. Complete purchasing information in the petrochemical, industrial gas, and polymer product sectors was not available.

In general, it can be seen that the cogeneration of electricity is not widely used in these sectors.

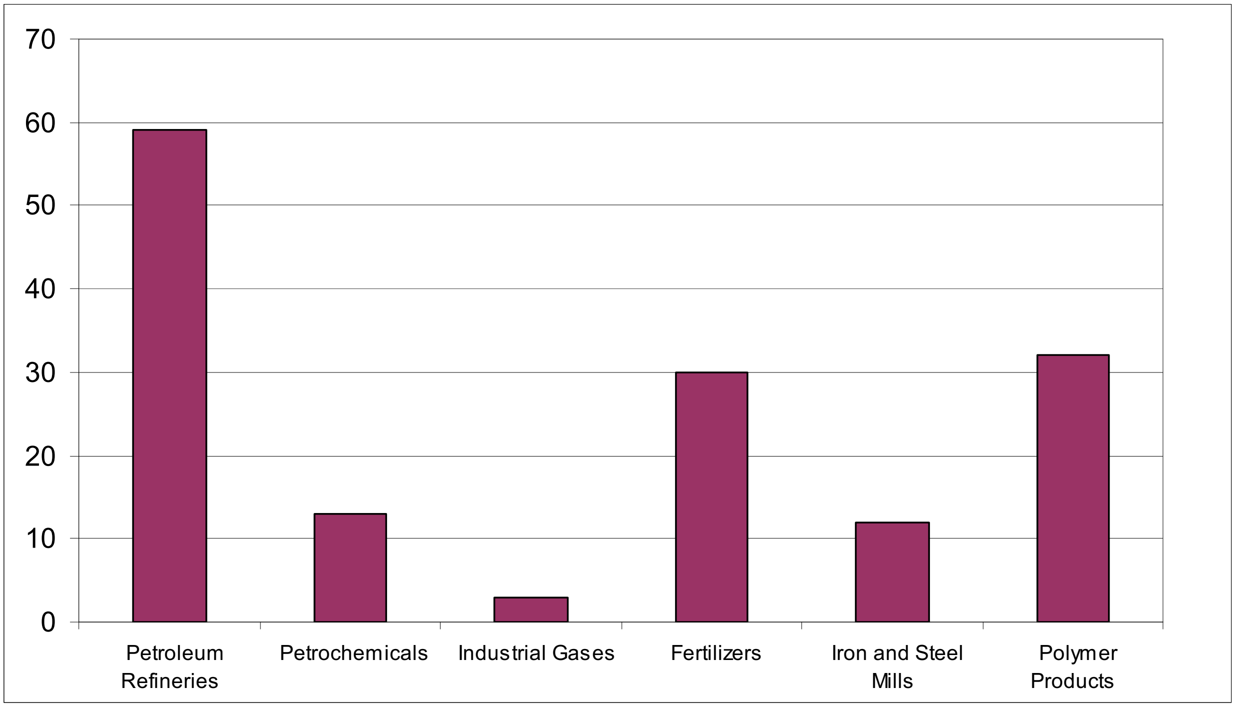

Figure 3-4. Establishments with Cogeneration Technology in Use, 2002 (Reference 2)

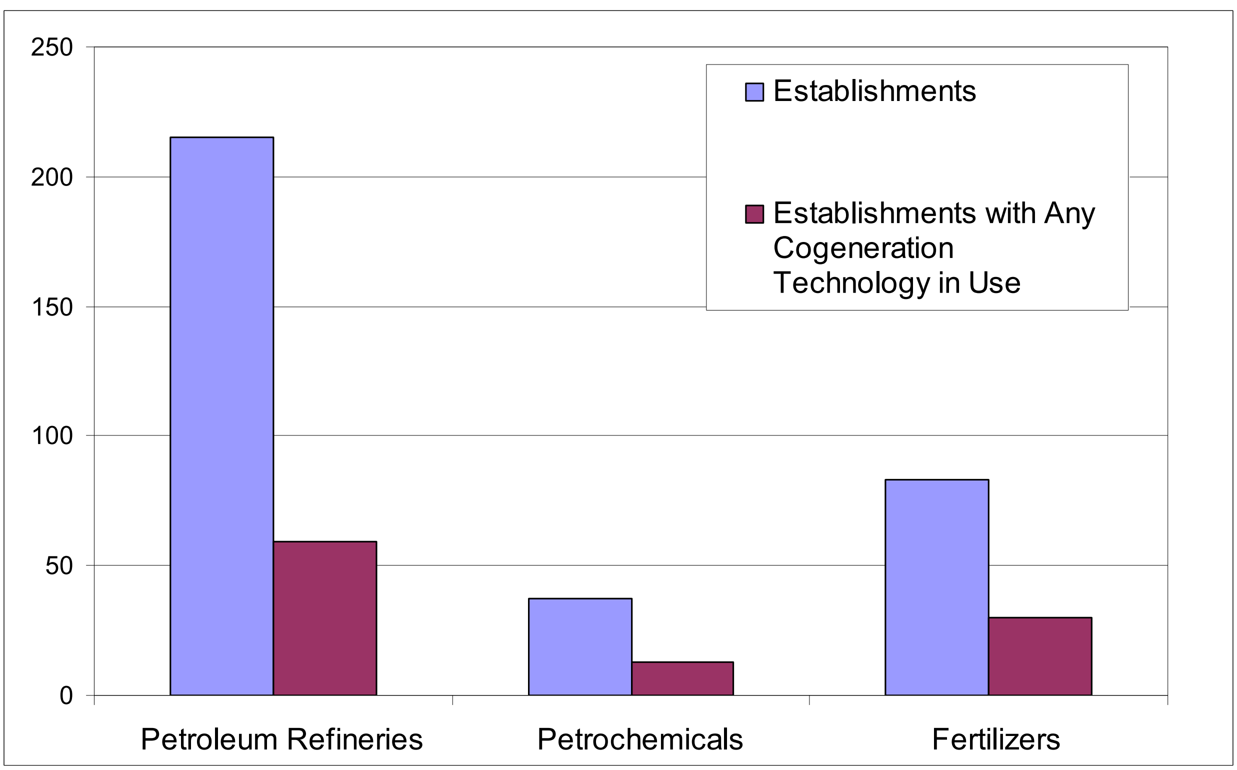

Figure 3-5. Establishments: Total vs. Cogeneration, 2002 (Reference 2)

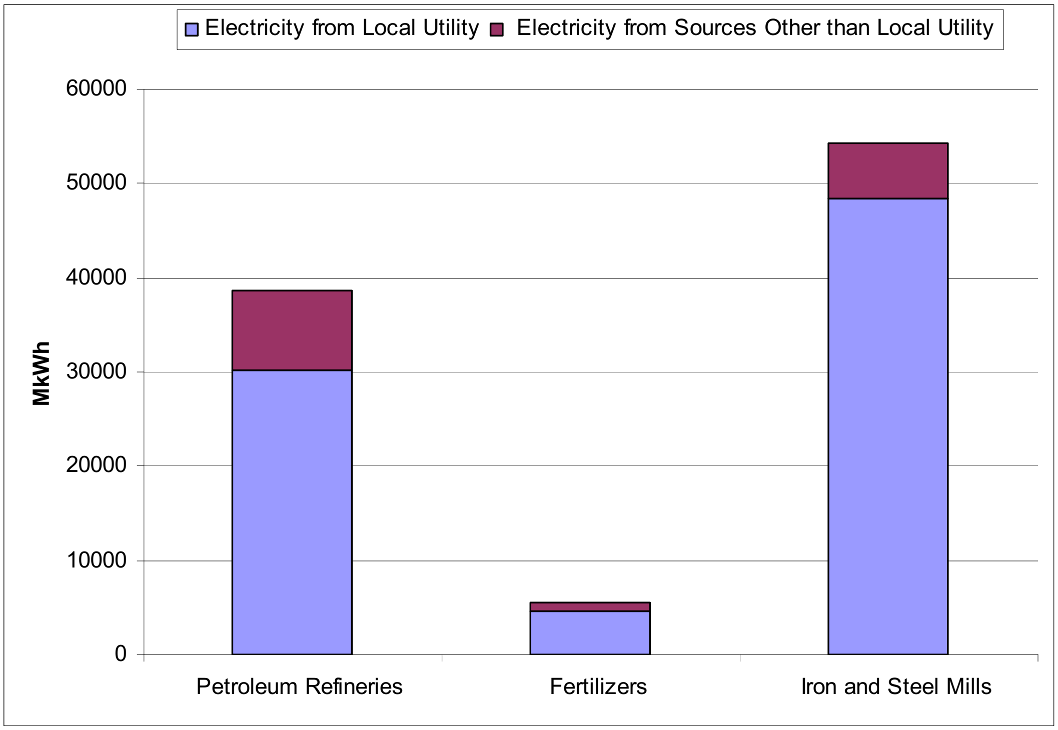

Figure 3-6. Purchases of Electricity (Reference 2)

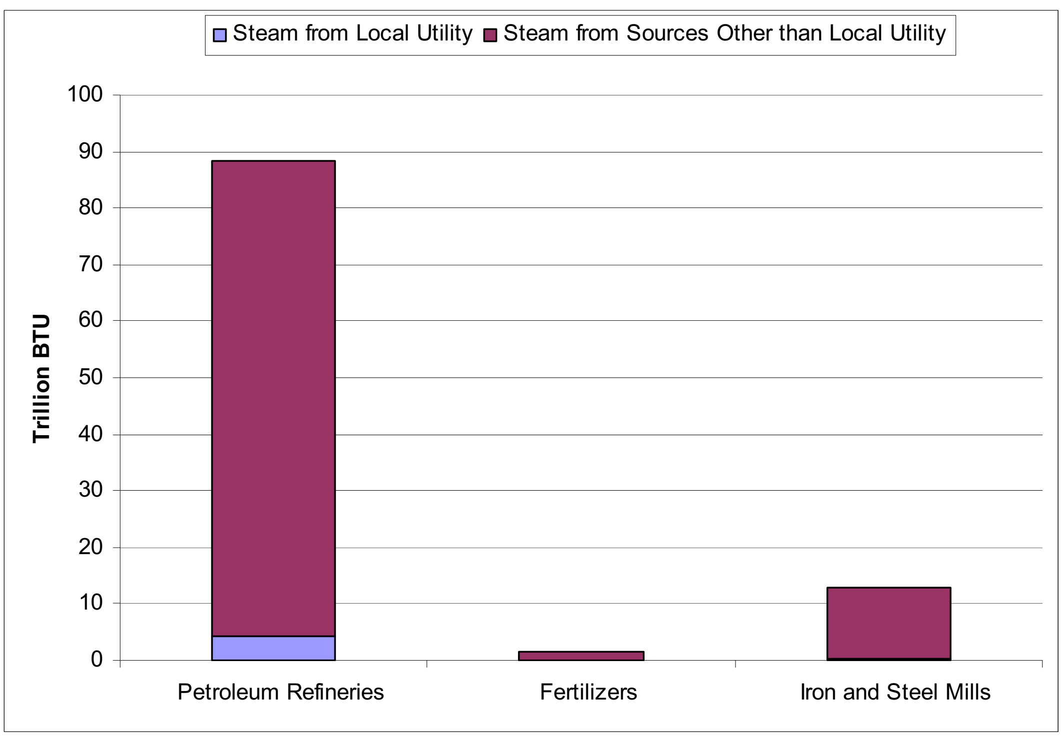

Figure 3-7. Purchases of Steam (Reference 2)

3.5 Reliability Requirements

The sensitivity of a given production process to interruptions in the supply of process energy can vary. The reliability requirements of each of these processes are considered with respect to the need for multiple reactor modules or backup direct-fired units. A survey of the companies engaging in these production methods will ultimately serve to augment and clarify this discussion.

Nearly all of the identified applications will likely require some form of redundancy, whether it is in the form of additional reactor modules or fossil-fired boilers. This may be more of a concern for reactor designs which do not have on-line refueling capability. Certain applications such as petroleum refining, petrochemical processing, and in-situ bitumen extraction and upgrading can be extremely sensitive to unexpected loss of process energy during operations.

If the delivery of steam is lost with in-situ bitumen extraction, the oil sands will begin to cool and will need to be reheated, losing large amounts of energy, time, and production. For petroleum refining and petrochemical processes, steam production usually requires at least 1 backup unit and other critical processes require 2 backup units.

3.6 Site Requirements

Certain applications have limitations on the location of the HTGR plant. Typical plant locations are often determined by the need to be close to feedstocks, fuel, transportation, or other resources. A very remote site, not easily accessible, could have difficulty in receiving large reactor plant components. This could affect plant size considerations.

One example of such a limitation is the use of an HTGR plant for oil recovery in remote areas of Canada. On the other hand, petroleum refineries are generally located near large sea ports where they can be accessed by oil tankers (e.g., Gulf Coast, New Jersey, California). Petrochemical plants are usually located near the refineries, the sources of their feedstocks. Process plants that are dependant on natural gas as a feedstock are sited where natural gas can be easily accessed or is inexpensive. This includes fertilizer and other SMR plants and DRI plants. A survey of the companies engaging in the various production methods will ultimately serve to augment and clarify this discussion.

3.7 Module Size

Based on the preliminary energy, reliability and site requirements for near-term HTGR applications, the following conclusions were reached with respect to total thermal plant and module size for typical applications:

- The thermal demand for a typical 200,000 bpd complex coking refinery is approximately 1100 MWt (7% steam, 76% heat, 17% electricity). Refining reliability requirements would suggest that a minimum of three modules be provided. The production capacity of the refinery will dictate the number of modules required. An acceptable module size would be in the range of 400-600 MWt.

- The thermal demand for 100,000 bpd of in-situ bitumen extraction is approximately 1270 MWt (99% steam and heat). Reliability requirements would suggest that a minimum of two modules be provided. A module size of 400-600 MWt could extract approximately 60 to 90 thousand bpd of bitumen.

- The thermal demand for a 100 million scfd steam methane reforming unit is approximately 130 MWt (56% steam, 37% heat, 7% electricity). Given the small module size that would be required for this application, it is likely that it would be coupled with other applications, such as electricity and steam production for other processes.

Each HTGR vendor (AREVA, General Atomics, and Westinghouse) has conducted studies in which HTGR module size and projected output were estimated. Some module sizing information from these studies is available in Appendices A-C. A survey of the companies engaging in the various production methods will ultimately serve to augment and clarify this discussion.

4

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A

AREVA Meeting Summary

Date: Friday, March 7, 2008

Location: Areva NP, Lynchburg, VA

Subject: Next Generation Nuclear Plant (NGNP) - Discuss the Process Energy Needs of Commercial Industrial Plants that Relate to Possible Application of High Temperature Gas Reactor Technology

Purpose: To review results of prior market surveys of industrial process energy usage, to assist NGNP in selecting appropriate operating conditions and plant sizes that would be in harmony with commercial needs.

Conclusions of Areva Market Survey Review:

1. **Plant Size**: The initial plant size for HTGR should be 500-600 MWt. Larger plant size has an economy of scale, as long as the limits for passive safety are not exceeded. Although there may be some market for smaller units, it is easier to downsize from an approved reactor size than to increase. For larger overall energy needs, such as 2400 MWt, a four-pack of 600 MWt modules would not be excessive and would provide redundancy of energy source. Redundancy for smaller energy plants could be provided by backup gas-fired plants on a more economical basis than to have multiple nuclear reactors. Advantages for smaller sizes would include smaller sizes of heavy equipment, such as reactor vessels. AREVA believes that an HTGR that delivered steam at 400-500˚C and heat at 600-900˚C would be applicable to a vast majority of the noted HTGR applications.

2. **Applications**: Based on the results of an extensive international study that was performed to determine the potential role of HTGR technology in the next 50 years, Areva noted the following industries were of interest:

    a. Steel (direct reduction of iron)
    b. Alumina (a low temperature process ~250˚C)
    c. Cl-VCM-PVC
    d. Fertilizers
    e. Refineries
    f. Hydrogen
    g. Liquid Fuels
    h. Chemicals

Based on the study, steel was considered to be the industry with the highest need and the largest number of potential HTGRs. Demand for refineries and chemicals was high, but demand for fertilizers and hydrogen was predicted to be low. This analysis did not reflect needs unique to the United States, where fertilizer, refineries, hydrogen, liquid fuels, and chemical applications all had greater potential than steel applications.

3. **Oil Recovery**: Oil recovery, using Kerogen retorting and extraction from oil shale, was considered to be a good match with HTGR capabilities. Bitumen extraction and upgrading from oil sands was also considered promising. Because of the remote nature of oil sands fields in Canada, the possibility exists of building a large reactor equipment fabrication facility near the oil sands should large numbers of HTGRs be ordered.

4. **Hydrogen**: It was estimated that the world demand for hydrogen by the year 2020 would require 220 HTGRs of the 600 MWt size.

5. For near term applications, the markets that could most successfully be targeted are those that could utilize steam from an HTGR source. New plants were more promising due to the difficulty with integration of HTGR technology with already optimized industrial plants. Plants that require modifications to use process heat from HTGRs would require a longer term development, such as steam methane reforming and iron ore processing.

Other Observations:

1. **Cement**: A possible application may arise for HTGR from cement production due to developments which enable cement to be processed at temperatures as low as 800˚C.

2. **Steam Methane Reforming**: HTGR process heat may be applicable to steam methane reforming which can occur at temperatures as low as 700˚C.

3. **Oil Refining**: Some new refineries planned for the future in Asia are expected to be very large (250,000 BPD, 3000 MW).

4. **Paper**: Paper production was not considered to be an application worth pursuing because of the low energy requirements (~5MW).

5. **Desalination**: Desalination of water is a potential application for HTGRs in various parts of the world. Two 600 MWt HTGRs could produce 1 million acre-feet per year of fresh water, which is about the size of demand in South Florida. Currently, this is not considered to be an application worth pursuing in the U.S. because of the lack of regulation on the way water is managed. Long-term, large capital investments like HTGRs are therefore a poor fit.

B

Westinghouse/PBMR/Shaw Meeting Summary

Date: Thursday, April 3, 2008

Location: Shaw Group, Cambridge, MA

Subject: Next Generation Nuclear Plant (NGNP) - Discuss the Process Energy Needs of Commercial Industrial Plants that Relate to Possible Application of High Temperature Gas Reactor Technology

Purpose: To review results of prior market surveys of industrial process energy usage, to assist NGNP in selecting appropriate operating conditions and plant sizes that would be in harmony with commercial needs.

Conclusions of Westinghouse/PBMR/Shaw Market Survey Review:

1. The first step of the PBMR process heat plant ("PHP") development path should involve a steam/cogeneration unit (reactor outlet temperature of ~750°C) for process industry needs. If natural gas prices remain above $8/MMBtu escalating at 2% per year in real terms, over 50 such cogeneration plants could be economically competitive in the United States. This builds on the Brayton cycle demonstration plant in South Africa which has a reactor outlet temperature of 900°C.

2. This would be followed by an HTGR that could provide process heat for hydrogen gas production using steam methane reforming (SMR). This would displace natural gas as a heat source, reducing methane required for hydrogen production, as well as reduce the overall emissions of CO_2. Reactor outlet temperatures in the range of 900°C are needed for efficient SMR Cogeneration plants.

3. Water-splitting has a long term added value for the full potential for coal-to-liquids and coal-to-gas production, as well as mass production of hydrogen and oxygen. These plants are considered to require reactor outlet temperatures in the range of 950°C or higher.

4. Critical path to market applications is nuclear licensing for steam plant applications and technology development for higher temperature applications.

Summary of Presentation:

1. The HTGR technology is well suited for process heat needs. It is projected to produce ~750°C process heat for steam applications and up to 950°C process heat for high temperature applications. Its size of 500MWt modular units and meltdown-proof safety

margins will increase the likelihood that regulators, the public and investors will accept the idea of locating nuclear plants in proximity to process plants.

2. Nuclear plants are not likely to be exposed to long-term fuel supply volatility, disruptions or rising penalties for CO_2 concerns. Nuclear process heat is competitive with natural gas at current price projections. PBMRs have an advantage of online refueling which increases availability.

3. For initial steam plant applications, a 500MWt plant with a ~750°C reactor outlet temperature would have the advantage of using conventional materials and components, relatively small helium inventory and pressure boundary, and existing steam turbine and helium boiler experience. Such a plant would produce electricity and steam which would permit simple integration with the end-user processes. With minimum technology development needed, licensing would be the likely critical path to implementation.

4. Immediate steam plant applications include bitumen recovery from oil sands, heavy industry and other cogeneration, and water desalination. The use of HTGR technology is expected to achieve a simplified, proliferation-resistant nuclear reactor that competes with gas-fired combustion turbine combined cycle cogeneration applications.

5. Specific applications of HTGR technology were discussed:

   a) **In-Situ Oil Sands Plant**: In this concept, two 500 MWt reactors with 720°C reactor outlet temperature generate steam at 8 – 16 MPa and 300°C+ for oil extraction and also for steam-turbine electricity generation. Two reactor units are needed to support a given area producing 100,000 bbl/day of bitumen, and to ensure uninterrupted well temperatures. Feedwater needs and processing of return feedwater are important design considerations. Site accessibility difficulty is expected to be a factor in design of the modularized units. The market for these plants in the Canadian oil sands region is very large.

   b) **Steam Cogeneration Plant**: In this concept, a 500 MWt reactor with a ~750°C reactor outlet temperature produces up to 24 MPa steam at up to 585°C for process heat needs, with lower pressure/temperatures of steam being extracted as outputs of various turbine generators, optimized for the process. Reliability requirements depend on the processes supported, and the customized needs for steam and power sales. Conditioning of returning feedwater is closely linked with steam generator water chemistry requirements. Co-location of nuclear and chemical plants must be examined. Three examples of steam cogeneration plants were discussed, each of which was sized at about 500 MWt.

   c) **Nuclear Steam Methane Reforming**: In this concept, a single 500 MWt reactor with a 900°C reactor outlet temperature generates steam which is added to natural gas and water to produce hydrogen. These plants can generate steam, electricity and hydrogen as products for other process plants. Availability needs are tighter if tied directly to a process and less if tied to part of the hydrogen pipe-line system. Higher temperatures increase hydrogen production. Maintenance activities for catalyst and component rejuvenation need to be coordinated with end-user plant outages. An example of a SMR cogeneration plant was provided composed of two modules sized at 100 MWt which simultaneously provide electricity, 110 million scf/d of hydrogen, and 1.2 million lb/hr of steam to support a refinery which handles 300,000 bbl/d of crude oil.

d) **Water Splitting Plant**: In this concept, a 500 MWt HTGR with a 950°C reactor outlet temperature provides process heat to produce hydrogen and oxygen from high temperature hybrid sulfur process, as well as produces electricity and lower pressure extraction steam for other process needs. Extensive development is required to develop the hybrid sulfur process and IHX components on an industrial scale. Co-location of hydrogen production facilities with a nuclear plant could be a potential safety and licensing concern. New designs and severe conditions may result in frequent process plant outages for maintenance and equipment rejuvenation. Multiple reactors will be required to satisfy projected hydrogen demands, e.g. CTL complexes.

e) **Power Desalination Plants**: In the concept, a 500 MWt HTGR with a ~750°C reactor outlet temperature generates steam and electricity (140 – 180 MW) and uses lower pressure exhaust steam for water desalination. Economics depend on regional prices of power and water. (It was noted that these low temperature steam demands could be supplied by water cooled nuclear reactors and are not uniquely provided by HTGR technology, although water cooled nuclear reactors have additional siting and planning constraints which may make integration of water desalination significantly more difficult.)

6. HTGR markets were discussed:

a) **Market Studies**: Market studies for power and process heat applications for PBMRs indicated that the implementation of CO_2 constraints, energy costs, supply security, economic growth and industrial development directly impact the markets for HTGRs. Markets for HTGRs include steam and electricity for heavy oil recovery, industrial facilities, desalination plants and district energy.

b) **Cogeneration Markets**: In 2005, U.S. energy distribution in the combined heat and power market was 54% for electricity and 46% for heat. About 60% of this capacity was large enough to be served by 500 MWt HTGRs. Natural gas was the predominant fuel, followed by coal. An estimate of the U.S. cogeneration market size is roughly the equivalent of fifty 500MWt HTGRs in the 2015 – 2030 time period.

c) **Heavy Oil Recovery Market**: The location of oil sands markets in the U.S. and Canada as well as outside America were discussed.

d) **Potential Hydrogen Markets**: U.S. hydrogen market growth is uncertain due to limited planned refinery expansion and emergence of hydrogen as transportation fuel depending on economics. New CTL and CTG projects may provide supporting economics, and increasing gas costs and CO_2 penalties may make nuclear hydrogen economical. Projecting the number of plants likely for hydrogen production is difficult.

e) **Economics**: Several comparisons were made using economic assessments as a basis for making decisions on using nuclear heat for production of steam, power, and hydrogen for a variety of applications.

f) **Outreach**: HTGR public outreach initiatives and industry collaborations need to be developed.

C

General Atomics Meeting Summary

Date: Thursday, April 17, 2008

Location: General Atomics, Washington, DC

Subject: Next Generation Nuclear Plant (NGNP) - Discuss the Process Energy Needs of Commercial Industrial Plants that Relate to Possible Application of High Temperature Gas Reactor Technology

Purpose: To review results of prior market surveys of industrial process energy usage, to assist NGNP in selecting appropriate operating conditions and plant sizes that would be in harmony with commercial needs.

Conclusions of General Atomics Market Survey Review:

1. The HTGR technology can help solve the US energy problems of excessive dependence on fossil fuels with a diminishing supply and undesirable consequences of CO_2 generation. This solution consists of near term applications and then longer term applications.

2. Near term applications for HTGR technology are those that use steam and cogenerated electricity from nuclear reactors to supply process energy needs. Typical near term applications include:

   - Heavy oil recovery
   - Oil from tar sands
   - Industrial process steam (e.g., refineries)
   - Coal liquefaction (CTL)
   - Coal gasification

3. Longer term development and applications include those which require development of very challenging high temperature pressure vessels, intermediate heat exchangers, electrolysis materials, and chemical processes, and which require complex changes to existing industrial equipment and processes to utilize a new source of process energy. These include development of nuclear hydrogen production using processes at 900-950°C., demonstrating such processes on a production scale in NGNP, and optimizing the use of HTGR technology for all applications.

Summary of Presentation:

1. The total energy use from oil in the US is equivalent to the thermal energy produced by 2,000 HTGRs (600 MWt each). The solution to a transition from fossil fuels will be to develop a sustainable mix of energy types. In the near term, this will provide security and competition to reduce costs, will reduce CO_2 emissions, and will implement practical

means while longer term solutions, such as hydrogen for transportation, are developed. Nuclear steam and electricity applications and the development of synthetic fuels from coal are examples of near term goals. The US has enormous coal reserves, estimated at almost 500 billion tons, but our economy is geared to using liquid fuels (oil) or gas (natural gas) energy sources. Therefore, part of the near term solution is to convert coal to useful liquid and gaseous fuel in an environmentally acceptable fashion.

2. Toward this end, GA has studied near term applications of process steam from HTGRs for heavy oil recovery, tar sands oil recovery, coal liquefaction by steam reduction of coal (SRC), coal liquefaction by Hydrogen-coal process, coal gasification, electricity and steam for steel mills and aluminum refining, district heating and desalination.

3. For the longer term, GA has studied methanol production by hydro-gasification, hydrogen production by steam methane reforming, and hydrogen production by thermo-chemical water-splitting.

4. Examples of Plant Sizing for Applications Studied by GA:

   a) **Cogeneration of Steam and Electricity**: A typical HTGR plant sized at 600 MWt with primary coolant at 700°C and 7 MPa could be used to generate electricity and steam at 540°C and 17 MPa.

   b) **Heavy Oil Recovery**: The above HTGR could produce 150 MWe for field use and sale, while generating 260°C steam at 4.5 MPa for oil recovery and 164°C steam at 0.7 MPa for dewatering. This could generate up to 26,000 bbl/day of oil. An arrangement of two 600 MWt HTGRs could be used to provide 900 MWt of process steam at 260°C and 3.5 MPa, and 1 MWe for pumping power, to produce 35,000 bbl/day over a 32 year lifetime for a 10 square mile oil field section, at a depth of 2,300 feet. The costs for this application of HTGR energy would be competitive with current methods.

   c) **Tar Sands Oil Recovery**: HTGRs could be used for recovery of bitumen from oil sands, by the Steam Assisted Gravity Drainage (SAGD) method. As an example, generation of 1100 MWt, both as 335°C steam at 14 MPa for well injection and 278°C steam at 6 MPa for water treatment and auxiliaries, together with generation of 83 MWe for recovery and upgrading, could produce 44,000 bbl of bitumen per day for up to 30 years in selected oil field areas. About a third of Canada's oil production is from oil sands and, in the USA, there are an estimated 30 billion bbl of oil in tar sands, so a large number of HTGRs could be used for this purpose. The cost of nuclear heat was competitive with existing natural gas usage, based on 2003 costs of $3.50/MMBtu. In addition, large quantities of hydrogen are needed for bitumen upgrading at these sites and the future use of HTGRs for hydrogen production could be added to this nuclear reactor process heat support.

   d) **Coal to Liquids (CTL) - Direct Liquefaction Process**: HTGRs could be used to provide the steam, electricity, process heat and hydrogen needed for the manufacture of synthetic crude oil, diesel and gasoline from coal. In this application, two 600 MWt HTGR modules could provide 1.4 million lbs/hr of 538°C steam at 17 MPa and 180 MWe, which could convert 30,000 tons of coal per day into 81,000 bbl of Syncrude and 122,000 MMBtu of fuel gas.

e) **CTL - Solvent Refined Coal (SRCII) Process**: Two 600 MWt HTGRs could provide 987 MWt as 450°C steam at 1.4 MPa, and 122 MWe, to convert 26,800 tons of coal/day into 175,000 BOE (barrels of oil equivalent) of liquid fuels per day and 69,440 BOE of methane per day (403 million scf/d).

f) **CTL - H-Coal Process**: Using the H-Coal catalytic hydrogenation process, two 600 MWt HTGRs could provide 755 MWt as 450°C steam at 17 MPa, and 251 MWe, to convert 30,000 tons of coal per day into 81,000 bbl of Syncrude per day and 122,000 MMBtu/day (21,000 BOE) of fuel gas.

g) **Coal Gasification**: Using a catalytic coal gasification (CCG) process, HTGRs could provide 1136 MWt of 704°C steam at 3.45 MPa, and 147 MWe, to convert 14,500 tons of coal per day to 43,000 BOE per day of substitute natural gas.

h) **Steel Mills**: Using open hearth steel making process, HTGR which provides 295 MWt as 385°C steam at 4.95 MPa, and 240 MWe can be used in the production of 7.2 million tons per year of steel.

i) **Aluminum Refining**: Using the Bayer process for aluminum oxide production and electrolysis to obtain aluminum, HTGRs could provide 317 MWt as steam at 320°C at 5 MPa, 94 MWe for the process and 450 MWe for electrolysis of alumina, to produce 800,000 tons per year of alumina (Al_2O_3).

j) **Coal to Methanol Production**: Using the hydro-gasification process, HTGRs could provide 1800 MWt as 980°C steam at 7.2 MPa, 780°C steam at 1.1 MPa and 240°C steam at 7.2 MPa, as well as 300 MWe to convert 3,000 tons of anthracite coal and 1500 tons of CH_4 per day into 6,500 tons (24,400 BOE) per day of methanol.

k) **Hydrogen Production by Electrolysis**: Using nuclear generated electric power and low temperature electrolysis for production of hydrogen gas from water results in only about 24% efficiency for water-cooled reactors and 36% for HTGRs at medium temperatures. Going to temperatures as high as 900°C for electrolysis processes either for water or for hybrid processes, can raise the efficiency of the process up to 50%. Based on projections of 200 million tons per year of hydrogen if transportation needs are met largely by hydrogen, even the 50 % efficient process would require 9 times our current (104 reactors) nuclear capacity.

l) **Hydrogen Production by Steam Methane Reforming (SMR)**: An HTGR can provide 600 MWt of 800°C steam at 1.2 MPa to convert methane to 5,400 BOE per day of hydrogen.

m) **Hydrogen Production by Thermochemical Water-Splitting**: If the sulfur iodine (SI) method for thermo-chemical water-splitting is successfully developed into an industrial scale process, HTGRs could provide 2400 MWt of 900°C steam at 7 MPa and 800 MWe to produce 8.54 million BOE per year of hydrogen.

MPR
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August 8, 2008

Phil Hildebrandt
NGNP Project – Idaho National Laboratory
P.O. Box 1625
Idaho Falls, ID 83415-3780

Subject: Number of High Temperature Gas-cooled Reactors that Could Hypothetically Be Applied to U.S. Hydrogen Production and to Canadian Oil Sands Recovery

Dear Phil:

Per your request, this letter submits two evaluations regarding hypothetical applications of High Temperature Gas-cooled Reactors (HTGRs) to industrial processes.

The enclosed evaluation of U.S. annual hydrogen production provides estimated numbers of HTGRs 1) to replace energy needed to for hydrogen produced by steam methane reforming (SMR); 2) to replace the lost heat capacity of natural gas used as a feedstock for SMR; and, 3) to replace all natural gas used as a feedstock for hydrogen production by using electrolysis with water as feedstock. The evaluation compares low temperature electrolysis (LTE) and high temperature electrolysis (HTE) processes. The evaluation provides HTGR estimates based on both annual US merchant hydrogen demand (the amount sold to others) and total annual U.S. hydrogen demand.

The enclosed evaluation on Canadian oil sands recovery estimates the number of HTGRs that could provide the energy needs for projected oil sands developments through 2050. This evaluation includes only energy needs associated with extraction of the bitumen and does not include energy for subsequent refining of the recovered product.

Please feel free to contact Joey Konefal or me if you have any comments or questions.

Sincerely,

Dave Rackiewicz

Dave Rackiewicz

Enclosures

cc: P. Mills
L. Demick

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Enclosure 1 to
MPR Letter Dated
August 8, 2008

Number of HTGRs Hypothetically Required for Different Aspects of Current U.S. Hydrogen Production

Purpose

This evaluation estimates how many High Temperature Gas-cooled Reactors (HTGRs) would be needed to provide energy for different aspects of current U.S. hydrogen production. This study uses the method reported in Reference 1 to evaluate energy needs for U.S. merchant hydrogen.

Approach

The total annual U.S. hydrogen production in 2005 was estimated at 9 million tonnes (metric tons), which is equivalent to 3.74 trillion scf (standard cubic feet at 1 atmosphere pressure and 60°F) (Reference 2).

The production of U.S. merchant hydrogen, which is hydrogen that is produced for sale to another user as an industrial gas, was about 2.5 million tonnes or 1.05 trillion scf in 2007 (Reference 3). About 95% of it was made by the Steam Methane Reforming (SMR) method.

The sources of hydrogen production other than merchant hydrogen, and the production processes used are difficult to quantify because this hydrogen is not sold and recorded. This so-called captive hydrogen is used as a feedstock for one process at the same manufacturer where it was produced in another process. As an example, U.S. refinery production of captive hydrogen in 2007 was about 3.6 million tonnes (Reference 3), and this used many feedstocks such as napthas, napthenes, paraffins, still gas and natural gas, and included processes such as cyclization and dehydrogenation, as well as steam reforming.

For simplicity, this evaluation will consider two different production quantities. The first will be U.S. merchant hydrogen production. The second will be the total estimated U.S. hydrogen production. The following will be included in estimating the number of equivalent HTGRs:

- **Merchant Hydrogen Supply**: The fraction of the 1.05 trillion scf made by SMR (95%) will be evaluated. This equates to 1.00 trillion scf (2.4 million tonnes).
- **Total Hydrogen Supply**: For simplicity and as an upper bound, the total U.S. hydrogen production, estimated at 3.74 trillion scf (9 million tonnes), will be assumed to be made solely by the SMR process.

For each of the above cases, the following evaluations will be performed:

- Provide Energy Loads for SMR Process: Calculate the number of HTGRs to provide all energy loads needed to produce U.S. merchant plant hydrogen using SMR.
- Replace Lost Heat from Natural Gas Feedstock: Measure the amount of natural gas used as feedstock, based on its heating value, and calculate the number of HTGRs required to provide the same heating capability that is lost to feedstock.
- Eliminate All Use of Natural Gas for Hydrogen Production: If the hydrogen production was entirely made by HTGRs using water as a feedstock, with either Low Temperature Electrolysis (LTE) or High Temperature Electrolysis (HTE) as a process, calculate the required number of HTGRs. The temperatures for LTE are less than 200°C and the temperatures for HTE are around 900-950°C.

Methodology

To calculate the number of HTGRs required for hydrogen production, the following inputs are required:

- Production Method Used
- Total Annual Production, *P* (scf in a yr)
- Production Energy, *E* (Btu/scf)
- Conceptual HTGR Plant Size, *S* (MWt)
- Plant Capacity Factor, *C*

The number of HTGRs, *N*, required is given by:

$$N = \frac{P * E}{S * C * 2.99 * 10^{10}} \qquad \text{Equation 1}$$

Calculations

1. Merchant Plant Production via SMR

As previously noted, the merchant plant hydrogen produced by SMR is 1.00×10^{12} scf (2007).

a. Provide Energy Loads for SMR Process: The number of HTGRs that would be needed to supply the energy requirements for producing US merchant hydrogen made via the SMR process was estimated in Reference 1 on the following basis:

The production energy for hydrogen via SMR is calculated in Reference 4 using energy input values for a hypothetical 57 million scfd (scf per day) reference plant. This plant uses natural gas as a fuel and feedstock but also requires steam and electricity from an external source.

The mass rate of steam required is:

$$\dot{M}_s = 1239 \frac{Mg}{day}$$

The amount of electrical energy required is:

$$\dot{E}_{elec} = 153{,}311 \frac{MJ}{day}$$

The mass rate of natural gas required for fuel is:

$$\dot{M}_{CH4\_fuel} = 43 \frac{Mg}{day}$$

The mass rate of natural gas required as a feedstock is:

$$\dot{M}_{CH4\_fs} = 392 \frac{Mg}{day}$$

The energy value of steam is assumed to be 1200 Btu/lb. Specific energies for natural gas are assumed to be 23,000 Btu/lb and 1030 Btu/scf. Finally, the thermal to electrical energy conversion efficiency is assumed to be 33% for SMR (not significant for SMR, see discussion about different efficiency values for electrolysis below).

The energy inputs per day for steam, electricity, and natural gas as a fuel are:

$$\dot{E}_s = \dot{M}_s \frac{2205 lb}{Mg} \frac{1200 Btu}{lb} \qquad \dot{E}_s = 3421 MMBtu/day$$

$$\dot{E}_{elec\_thermal} = \dot{E}_{elec} \frac{1}{0.33} \qquad \dot{E}_{elec\_thermal} = 436 MMBtu/day$$

$$\dot{E}_{CH4\_fuel} = \dot{M}_{CH4\_fuel} \frac{2205 lb}{Mg} \frac{23{,}000 Btu}{lb} \qquad \dot{E}_{CH4\_fuel} = 2181 MMBtu/day$$

The energy for the replacement of the steam, electricity, and fuel by an HTGR is therefore:

$$E_{SMR\_energy} = \frac{\dot{E}_s + \dot{E}_{elec\_thermal} + \dot{E}_{CH4\_fuel}}{57 * 10^6 \frac{scf}{day}} \qquad E_{SMR\_energy} = 106 \frac{Btu}{scf}$$

In Reference 1, a conceptual 500 MWt HTGR with a capacity factor of 0.85 is assumed.

$$S = 500 MWt \qquad C = 0.85$$

Therefore, from Equation 1, the number of HTGRs that can replace all energy sources in the SMR process for the production of merchant hydrogen is:

$$N_{SMR\_energy} = \frac{P_1 * E_{SMR\_energy}}{S * C * 2.99 * 10^{10}} \qquad N_{SMR\_energy} = 8$$

b. <u>Replace Lost Energy from Natural Gas Feedstock:</u> A way of comparing the amount of potential heating capability that is lost by using natural gas for the feedstock is to convert the feedstock into a number of HTGRs that could provide the same heating capability.

$$\dot{E}_{CH4\_fs} = \dot{M}_{CH4\_fs} \frac{2205 lb}{Mg} \frac{23{,}000 Btu}{lb} \qquad \dot{E}_{CH4\_fs} = 19{,}880 MMBtu/day$$

$$E_{SMR\_fs} = \frac{\dot{E}_{CH\_fs}}{57 * 10^6 \frac{scf}{day}} \qquad E_{SMR\_fs} = 349 \frac{Btu}{scf}$$

$$N_{SMR\_fs} = \frac{P_1 * E_{SMR\_fs}}{S * C * 2.99 * 10^{10}} \qquad N_{SMR\_fs} = 27$$

c. <u>Eliminate All Use of Natural Gas for Hydrogen Production</u>: The number of HTGRs it would take if no natural gas was used and all hydrogen was made by electrolysis with water as feedstock is shown below.

The thermal-to-hydrogen production efficiency of a given process is defined as the ratio of the lower heating value (LHV) of the hydrogen produced to the thermal energy required for production. The LHV of hydrogen is 290 Btu/scf (Reference 5). Studies from Reference 6 show that in a high temperature reactor (950°C outlet temperature) with a high power cycle efficiency (54.8%), the thermal-to-hydrogen production efficiencies of the LTE and HTE processes are:

$$\eta_{LTE} = 39\% \qquad \eta_{HTE} = 48\%$$

Determine the thermal energy required for electrolysis per scf of hydrogen:

$$E_{LTE} = 290 \frac{Btu}{scf} \frac{1}{\eta_{LTE}} = 744 \frac{Btu}{scf}$$

$$E_{HTE} = 290 \frac{Btu}{scf} \frac{1}{\eta_{HTE}} = 604 \frac{Btu}{scf}$$

The number of reactors needed to produce the 1.00 trillion scf of merchant hydrogen using LTE and HTE can be calculated:

$$N_{LTE} = \frac{P_{total} * E_{LTE}}{S * C * 2.99 * 10^{10}} \qquad N_{LTE} = 59$$

$$N_{HTE} = \frac{P_{total} * E_{HTE}}{S * C * 2.99 * 10^{10}} \qquad N_{HTE} = 48$$

The required number of HTGRs for LTE and HTE electrolysis methods can be compared to the combined 35 equivalent reactors for the SMR process in which the energy value of the SMR feedstock is expressed as equivalent reactors. The number of HTGRs required to produce 1.00 x 10^{12} scf of hydrogen using SMR, LTE and HTE methods are displayed graphically in Figure 1.

2. Total Hydrogen Demand

This section calculates the number of HTGRs required to produce the total U.S. hydrogen demand. using a single process. The use of SMR, LTE and HTE are compared, using the same techniques demonstrated above, including the assumption of a conceptual 500 MWt HTGR.

The total U.S. hydrogen demand in 2005 was 9 million tonnes, or in terms of scf:

$$P_{total} = 3.74 \times 10^{12}\, scf / yr$$

The number of HTGRs required for SMR is divided between replacement of energy (which is the steam, heat and electricity needed to run the SMR process) and the equivalent energy that is lost due to lost heating capacity of the feedstock (expressed as the number of HTGRs that would be required to replace the energy in the feedstock).

$$N_{SMR\_energy} = \frac{P_{total} * E_{SMR\_energy}}{S * C * 2.99 * 10^{10}} \qquad N_{SMR\_energy} = 31$$

$$N_{SMR\_fs} = \frac{P_{total} * E_{SMR\_fs}}{S * C * 2.99 * 10^{10}} \qquad N_{SMR\_fs} = 103$$

$$N_{LTE} = \frac{P_{total} * E_{LTE}}{S * C * 2.99 * 10^{10}} \qquad N_{LTE} = 219$$

$$N_{HTE} = \frac{P_{total} * E_{HTE}}{S * C * 2.99 * 10^{10}} \qquad N_{HTE} = 178$$

These values are graphically represented in Figure 2.

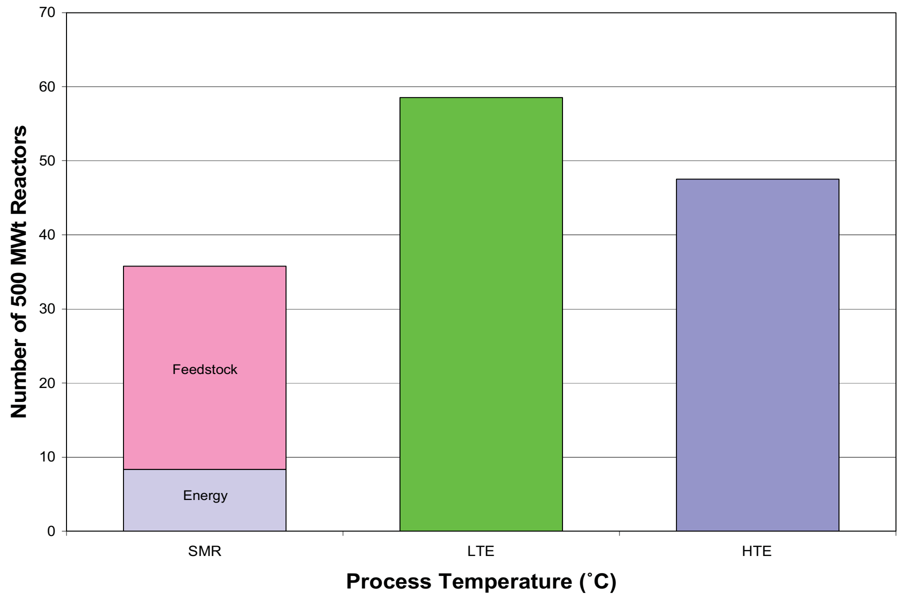

Figure 1. Number of HTGRs (950°C) to Meet 2.4 Million Tonnes U.S. Merchant Production Demand (1.00 x 10^{12} scf) by SMR*, LTE and HTE

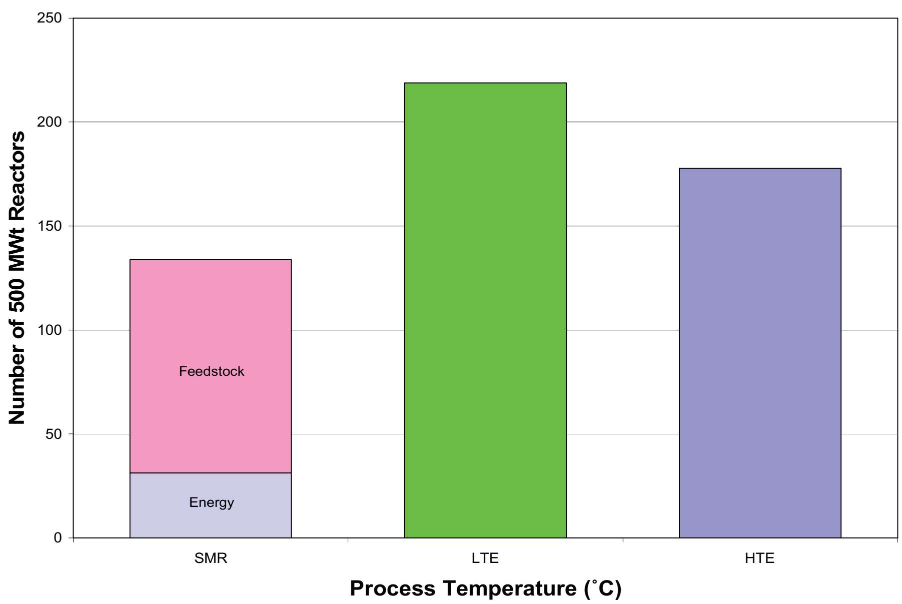

Figure 2. Number of HTGRs (950°C) to Meet 9 Million Tonnes U.S. Hydrogen Demand Assuming All is Produced by SMR*, LTE and HTE

Note: * If the SMR process is used, only the energy bar requires HTGRs. The Feedstock bar shows the amount of heat-making capacity lost due to use of natural gas as the feedstock. Thus, the total feedstock plus energy bar for the SMR process can be compared to the energy bars for the LTE and HTE processes.

References

1. Report MPR-3181, "Survey of HTGR Process Energy Applications," Revision 0.

2. U.S. DOE, "Today's Hydrogen Production Industry," www.fossil.energy.gov.

3. "2007 Hydrogen Production Data," Hydrogen Analysis Resource Center.

4. NREL/TP-570-27637, "Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming," Revised February 2001.

5. "Lower and Higher Heating Values of Fuels," Hydrogen Analysis Resource Center.

6. C. J. Steffen, Jr., M. G. McKellar, E. A. Harvego, and J. E. O'Brien, "The Effect of Electrolysis Temperature on Hydrogen Production Efficiency," ST-NH_2, ANS Conference, Boston, June 24-28, 2007.

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Enclosure 2 to
MPR Letter Dated
August 8, 2008

Number of HTGRs Hypothetically Required for Future Canadian Oil Sands Needs

1. Purpose

The purpose of this evaluation is to show how many 500 MWt (conceptual size) High Temperature Gas Reactors (HTGRs) would be needed to provide for the process energy requirements associated with present and future Canadian oil sands extraction plant developments.

2. Method

Reference 1 provided projections of oil recovery production developments in the Canadian oil sands region through 2050. The projections differentiate between open mining of near surface oil sands and "in-situ" recovery of bitumen extracted from deposits below the surface by various processes via drilled wells. Figure 1 predicts the production forecasts based on crash program scenarios (i.e., maximum rates of development).

The barrels per day (bbd) forecasted in Figure 1 were converted into a number of hypothetical reactors that could provide the necessary energy for bitumen recovery. The number of reactors was based on a conceptual 500 MWt HTGR with operational capacity factor of 0.85. This is the same basis that was used for the Reference 2 report which estimated the equivalent HTGRs for all industrial process energy needs. Based on the Reference 2 report, the following conversions were used for equating barrels per day (bbd) of bitumen recovery to required process energy in Megawatts-thermal (MWt):

- For Mining: 600 MWt will yield 100,000 bbd
- For In-Situ: 600 MWt will yield 50,000 bpd, based on a SAGD process (steam actuated gravity drain)

These conversions are rough estimates since the actual conversion rates are influenced by the quality of the oil sands and the steam to oil ratio (SOR) required for each well.

3. Summary

Table 1 shows the results of this evaluation. The prediction of 50 HTGRs for in-situ oil sands recovery in 2020, reported in Reference 2, is reflected by the underlined datum. Key conclusions from Table 1 are as follows:

a. Total annual thermal energy used for oil sands by 2050 is equivalent to 134 HTGRs.

b. Total annual thermal energy used only for in-situ applications by 2050 is equivalent to 127 HTGRs.

c. If the lifetimes of oil sands recovery plants are on the order of 30 years, most of the plants in support of mining will likely be in place by 2020. Further, the HTGR has unique capabilities for high temperature steam that is needed for in-situ applications. Therefore, the higher priority focus for HTGR should be toward in-situ plants.

By considering only the energy requirements for in-situ production starts after 2020, based on expected scheduled availability of HTGR plants, then up to 79 HTGRs could be applied by 2050 to oil sands development (see last column in Table 1).

Year	Mining Projection (M bpd)	*Number of 500 MWth Reactors for Mining*	In-Situ Projection (M bpd)	*Number of 500 MWth Reactors for In-Situ*	*Number of 500 MWt Reactors for all Energy*	*Number of Reactors for In-Situ Starting after 2020*
2005	*0.6*	*8*	*0.4*	*11*	*19*	*0*
2020	*2.3*	*32*	*1.7*	*48*	*80*	*0*
2030	*2.3*	*32*	*2.5*	*71*	*103*	*23*
2040	*2.3*	*32*	*3.5*	*99*	*131*	*51*
2050	*0.5*	*7*	*4.5*	*127*	*134*	*79*

Table 1 Number of HTGRs Needed to Provide Energy for Oil Sands Development

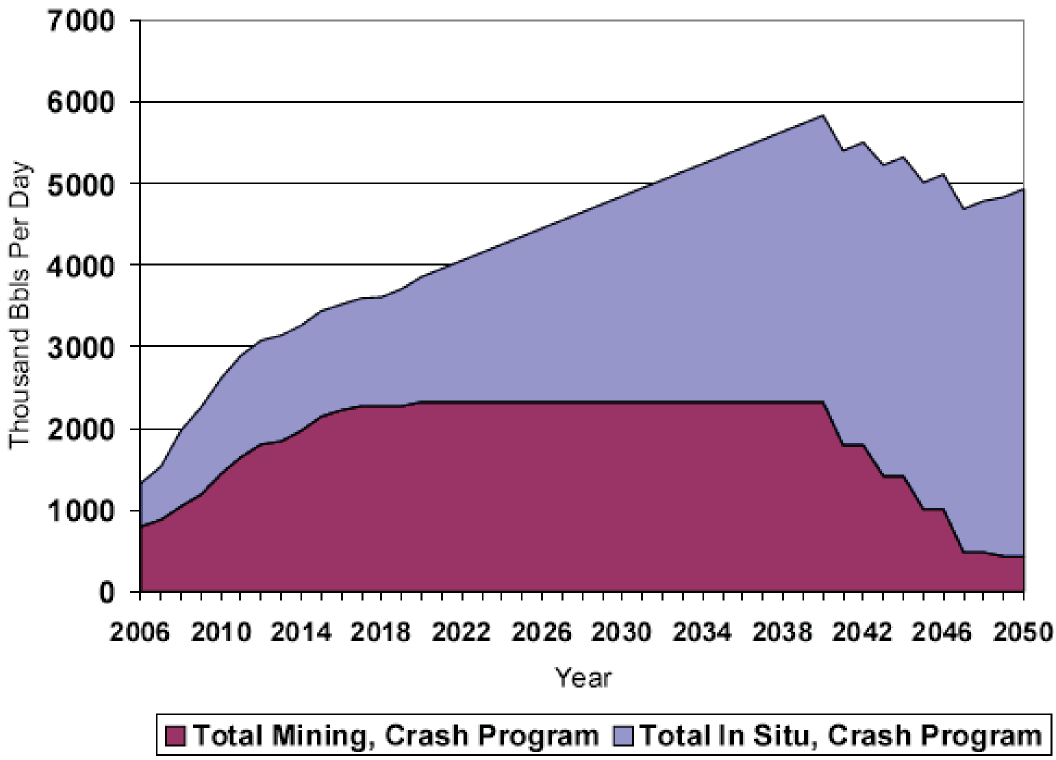

Figure 1: Long Term Oil Sands Crash Program Production Forecast [1]

4. References:

1. B. Söderbergh, F. Robelius and K. Aleklett, "A Crash Program Scenario for the Canadian Oil Sands Industry," June 8, 2006, http://www.peakoil.net/uhdsg/20060608EPOSArticlePdf.pdf

2. Report MPR-3181, "Survey of HTGR Process Energy Applications," Revision 0, May 2, 2008