Pebble Bed Modular Reactors—Status and Prospects

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Introduction and Summary

In August 2003, after three years of consideration, South African environmental officials issued favorable Records of Decision on the construction of a 110 Megawatt pebble bed modular reactor (PBMR), near Cape Town, and a fuel fabrication facility in Pelindaba. The agency found that "the PBMR has the potential to generate new programmes in nuclear safety, education, construction and research…[that may] attract large numbers of South Africans toward science and technology careers and…rejuvenate the workforce. There is geopolitical significance to location and advanced and original technology programme on the African continent…[particularly with] the potential for economic development and export of subsequent PBMR units."

The decision has been appealed by the City of Cape Town and the environmental group Earthlife Africa. The state-owned electric utility Eskom plans to begin procuring long lead time materials in early 2004, and begin site excavation in 2005. Eskom believes that the pebble bed reactor is significantly safer than light water reactors, and can therefore be built without many safety features—including containment and emergency cooling systems. This judgment has not been confirmed by South African regulators.

Eskom's Board has asked the Government for an "unconditional commitment" to fund next steps of this "strategic national demonstration project," and has released a preliminary cost estimate of 10 billion Rand (about $15,150/kW of capacity at current exchange rates). The utility has provisionally agreed to buy 10 reactors, "if the price is right." The developers believe that subsequent units will cost about $1,000 per kilowatt of capacity or less than one-fifteenth the cost of the demonstration project. This might result in total capital recovery and operating costs of 1.7 cents/kWh, significantly below the cost of new coal, gas, or wind fired plants now under consideration in many parts of the world. It is very far below the cost of the average nuclear reactor completed in the United States ($3,000/kW in mixed current 1984 dollars).[1] PBMR, the South African consortium developing the proposal, has estimated an export potential of more than 250 units in the future.

The accuracy of Eskom's short and long range cost estimates depend on a large number of extremely optimistic safety, reliability, and efficiency assumptions. Commercial experience with gas cooled power reactors began in the United Kingdom in 1956, with

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[1] Mixed current dollars are reasonably close to but slightly higher than constant dollars. Mixed current dollars include actual construction costs in the year they were incurred and interest costs on those expenditures, which are slightly greater than general inflation. It is certainly possible to provide the same number in constant dollars, though this requires complete information on actual cash flows.

Calder Hall, and ultimately led to the construction and operation of forty plants in the UK, Japan, Spain, Germany, France, and the US. Their record in meeting cost, reliability, and lifetime performance expectations is decidedly mixed.

The decision to proceed will depend on approvals for the project by the government coalition parties—the African National Congress and the New National Party. Both must decide whether this project is consistent with national economic development and is worth the price tag and risk, given other pressing needs.

It is clear that existing assets of the South African electricity industry are central to the success of many important national policy objectives. It is the cheapest large utility in the world (average rates of 2.3 cents/kWh). The industry was designed to meet the needs of large industries and a privileged white minority.

Over the past ten years, the goals have changed. Eskom (which is both a wholesale supplier and retail distributor) and the 400+ municipal distributors have invested 7 billion Rand to provide electricity to the majority population. Programs are underway to provide small amounts of free electricity to the poorest citizens. To help complete electrification and improve financial stability, the government has proposed that six regional electric distributors would take the place of more than 400 existing today.

South Africa rightly sees cheap electricity as a competitive advantage, and is using that resource to stimulate economic development—particularly along the coast. This has led to a decision to create a more competitive wholesale and retail electric system. The proposed steps include creation of a separate transmission company, creation of a wholesale power market, and privatization of 30 percent of Eskom's existing generation. Planners believe these steps will result in greater foreign investment, still lower power costs, and greater tariff equity (especially for larger industries). All of these developments affect the viability of the pebble bed project, subsequent units, and (because some are being implemented in other markets) export potential.

This review summarizes some of the issues relevant to the South African PBMR proposal. It is organized as follows: 1) background on South Africa's electric industry and gas graphite reactors; 2) technical features of the PBMR and whether the claims of high reliability, low maintenance, and easy licenseability are correct; 3) economics in South Africa, and factors that would affect such a project in the US; 4) the effect of industry restructuring on export potential; 5) other considerations, including resistance to proliferation and radioactive waste issues.

My principal conclusions are as follows:

- There are far too many technical uncertainties and design changes underway to have confidence in the cost or performance projections for the demonstration project, let alone the cost and performance projections for follow-on plants. There is no basis for the claim that such plants will be cheaper, safer, or more reliable than existing alternatives in South Africa or throughout the rest of the world.

- The demonstration project, if built on time and on budget, will cost roughly ten times more per kilowatt-hour than any number of alternatives.
- Major investments of time (at least five to seven years) and money (several hundred million dollars) would be required to bring this technology to a licenseable level in the United States. Even at that point, there would be a number of technical, economic, and performance barriers left before a US utility could entertain such a project. Many of these barriers might take an additional decade to overcome.
- Restructuring of the global electric industry, driven by changes in law, technologies, regulation, and markets, make export prospects look especially dubious.
- Eskom's request for an unconditional commitment to this demonstration project is at least extraordinary, and could set back—rather than enhance—the nation's key goals of economic development and electrification and infrastructure development for the majority population.

Background on South Africa and Gas Reactors

South Africa's energy and electricity systems have changed significantly since the fall of apartheid in 1994. The nation is the world's fifth largest coal producer, but has very limited reserves of either gas or crude oil. During the apartheid era, access to oil from the OPEC nations was severely limited. For that reason, the South African government built and operated a huge oil-from-coal plant (Sasol) that at peak supplied 30 percent of indigenous demand.

Eskom is the seventh largest electric utility in the world—supplying 95 percent of the country's electricity and 60 percent of all the electricity sold in Africa. It is also the cheapest large utility in the world. Coal supplies 87 percent of electricity demand, hydro 6 percent, nuclear 5 percent, and gas 2 percent. Coal deposits are concentrated in the Highveld, near Johannesburg. In the apartheid era, industrial development was clustered near Johannesburg.

But there was also growth on the coast, mainly around Durban and Cape Town.

To meet growing coastal needs, the Government estimated that it would be cheaper to build two nuclear reactors to serve Cape Town than build east-west transmission or move by coal by rail to the area. Ultimately, two 900 MWe French pressurized water reactors (Koeberg 1 and 2) were built just north of the city. Fear of nuclear fuel embargoes ultimately led to expensive (and dual-use) development of domestic facilities for mining, conversion, enrichment, and fabrication of light water reactor fuel.[2]

South Africa also has abundant wind potential, with some sites above 8 m/second and many above 6 m/second. Solar irradiation is also impressive—230 watts/square meter, versus 150 watts/square meter for parts of the US and 100 watts/square meter on average for the US and UK.

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[2] South Africa tested nuclear weapons in the early 1980s from uranium mined in South Africa and enriched at Pelindaba.

With household electrification, increased trade opportunities, and access to international markets, many electricity and energy policy issues have changed.

Forty percent of households had electric service in 1994; by 2000, nearly 80 percent of urban households and 46 percent of rural households had electricity. Oil can now be easily imported. Government subsidies to Sasol could be phased out. Uranium fuel can also be imported.

The focus of industrial development has also moved away from Johannesburg. With South Africa's cheap electricity and new export opportunities, energy intensive industries have begun to locate on the coast. There is a new 850 MWe aluminium smelter in Richards Bay—the eastern coast from Durban—and a 200 MWe steel mill at Saldanha, up the western coast from Cape Town.

Many questions should be asked and answered before the project proceeds. Is the development investment of 10 billion Rand in PBMR technology appropriate, given other pressing infrastructure investment needs? Is the demonstration project consistent with or not consistent with the goals of coastal industry development and electrification? Is the 15-fold cost reduction for subsequent units credible? More traditionally, are there cheaper and more reliable strategies than the PBMR demonstration project for accomplishing these national goals? As an energy and development strategy, is the nation building new resources to attract industries that cannot afford the incremental cost, and might depart as swiftly as they arrive? How realistic is the expectation for worldwide exports of PBMR technologies?

Many of these questions can't be answered without analysis that is beyond the scope of this report. What can be addressed are the maturity of the technology, the credibility of the safety, reliability, and cost projections, and the potential for fossil and renewable energy alternatives and efficiency improvements.

Current Eskom materials provide some information on the size and design of the PBMR. Additional information is available from the International Atomic Energy Agency, the Idaho National Environmental and Engineering Laboratory, the Massachusetts Institute of Technology, and the US Nuclear Regulatory Commission. The development consortium currently includes Eskom, British Nuclear Fuels Limited (BNFL), and the Industrial Development Corporation of South Africa. The US electric utility Exelon dropped out of the partnership last year. BNFL is bankrupt, and will be reorganized this year. Many organizations throughout the world are nevertheless participating in the analysis and development effort.

Eskom's argument for the project rests more on export potential than on the need for or cost-effectiveness of the proposed project.   One of the least stable aspects of the pebble bed project is its design—over the last two years, the physical size of the plant has changed, the enrichment level of the fuel has changed (from 8 to 9.6% U-235), the output of the plant has changed (from 110 to 137 MWe—this in the past month), the number of pebbles in the core has changed (from 440,000 to 452,000), and the average of cycles before the pebbles are removed has changed (from ten to six).[3]

Ordinarily an economic analysis would incorporate:

- reasonably stable financial factors (return requirements, debt/equity ratio, depreciation schedule, discount rate, and taxes);
- capital construction costs (including interest during construction and construction duration), large capitalized replacements made during the physical life, and the costs of decommissioning;
- capacity factor;
- mass balances for steps in the nuclear fuel cycle, and associated costs (uranium mining, milling, conversion to UF_6, reconversion, fuel fabrication, fuel storage, disposal, lead times for procurement, and interest costs on fuel in inventory); and
- operations, maintenance, and security costs.

At some point, it would advisable to conduct such an analysis, for Eskom specifically and for potential buyers abroad, whether they are merchant plant operators dependent on wholesale market prices for cost recovery or traditional "rate base" utilities able to include many costs in regulated retail tariffs. The details necessary to do any of these calculations are either not available, or are in flux.

The current design is primarily based two German reactors—the AVR and THTR.

The first of these reactors—the 15 MWe *Arbeitsgemeinschaft Versuchsreaktor* or AVR—began operations in 1967 using particle fueled, graphite spheres 6 cm in diameter that traveled downward through the core. Experiments with AVR found that some areas of the core exceeded 1280 C, well above the maximum design temperature of 1150 C.[4] The performance of the reactor was generally good throughout its 21 years of operation.

The record of follow-on plants is less comforting. In the US, the 330 MWe Fort St Vrain (US) plant operated for about 10 years, but with a host of maladies that limited its lifetime capacity factor to 17.8 percent—less than two years of effective full power operation. The plant generated its first electricity in January 1979, and was finally shut down in August 1989. Difficulties included core thermal fluctuations (1977–1978), failure of helium circulator seals (1979–1980), persistent control rod drive problems, and water contamination of the primary helium circuit (1982–1987).[5] At one point, on-site operations and maintenance staff numbered 965, which translated into operations and maintenance charges for that year of more than 20 cents/kWh, not including fuel, capacity additions, or recovery of initial capital costs.

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[3] Some examples include physical size of the confinement building (conflicting Eskom numbers), number of pellets in the core (440,000 Eskom vs 452,000 Ion), enrichment level (8 percent in 2002 report, 9.6 percent in 2003), average number of cycles before pebbles and removed (10 on Eskom website vs 6 in Ion).

[4] International Atomic Energy Agency, "Fuel Performance and Fission Product Behavior in Gas-Cooled Reactors," IAEA TECDOC 978, November 1997.

[5] Pre-filed Testimony of Jim Harding and Dale Bridenbaugh, MHB Technical Associates, before the Colorado Public Utilities Commission, February 1987.

The 300 MWe thorium high temperature German reactor (known as *Hamm-Uentrop* or THTR-300) began construction in 1971, but was not operational until late 1985. Its cost ballooned from an original estimate of 650 million Marks to 4 billion Marks. It was shut down less than four years later, mainly for financial reasons. The main relevant performance problem involved the tendency of fuel pebbles to stick in the continuous refuelling system piping. Most of the stuck pebbles were mechanically damaged during insertions of control rods into the pebble bed. Human error during one such event led to an offsite release of radioactivity, and contributed to the decision to shut down the plant. On the basis of this experience, the PBMR does not include in-core control rods.

It is worth noting, at this juncture, that China also has a gas-graphite reactor program underway. The first planned units contemplate the use of pebble bed fuel, large unit size (200–640 MW electric capacity), and steam generation (rather than gas turbine generation) in a secondary water loop. The fundamental weakness of this approach is in the heat exchanger, which functions as a large radiator, allowing the high temperature helium gas to pass its heat to water flowing through thousands of small, thin channels to the steam generator, and thence to the turbine. Pinhole leaks or larger leaks are almost inevitable, and the result is water contamination of the primary helium circuit. The risks and complications of that problem are discussed in greater detail below. Suffice it to say for now that no gas-graphite reactor with secondary water cooling—much like Fort St Vrain—has been a commercial success.[6]

The lack of extensive long-run operating experience with similar reactors—however theoretically safe—makes the pebble bed reactor project risky.

Characteristics of Pebble Bed Modular Reactors

Eskom contemplates that a single site might contain ten pebble bed reactor modules. Individual reactors would be contained in a single confinement (i.e., not pressure resistant) building 36 meters wide, 63 meters long, and 55 meters tall (22 meters of which are below ground). As many as ten reactors might share a single control room.

The core of a PBMR contains not fuel rods but 452,000 “pebbles” packed in a vessel that is less than 2 meters in internal diameter and 11 meters tall. Seventy five percent are fuel pebbles; the remaining pebbles are pure graphite. Each fuel pebble contains 15,000 “microspheres” of uranium fuel that must be very specially fabricated. The internal 0.5 millimeter microsphere is uranium (enriched to 9.6 percent U-235). This fuel is coated with a dense layer of pyrolytic carbon, a layer of silicon carbide, and an outer carbon layer. With coatings, each “TRISO” (for three isotropic layers) sphere is slightly less than one mm in diameter. The 15,000 spheres are then mixed in a graphite matrix and pressed and sintered into a “pebble” about 6 cm in diameter. A single core load requires high quality fabrication of nearly 5 billion microspheres.

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[6] All the other core or fuel performance issues also apply, and some additional challenges may be associated with larger unit size.

The core geometry—and presence of graphite—contributes in three ways to "inherent safety." It yields a power density of less than 5 megawatts thermal per cubic foot, about ten times less than the typical power density of a light water reactor. The surface area of the pebbles and mass of the core create much opportunity to dissipate decay heat. Proponents of pebble bed technology argue that these forms of heat loss overwhelm the potential for the core to heat up, and potentially melt down, after a loss of coolant accident.

The enduring presence of the moderator also improves safety. In a light water reactor, water is used both to cool the core and to moderate the reaction. When coolant is lost, the moderator is lost as well. In a gas-graphite reactor, the graphite remains after the possible loss of helium coolant. As the fuel heats, graphite yields a strongly negative coefficient of reactivity, retarding the fission process.[7] These features give rise to the expectation—not proved—that pebble bed reactors do not need, most importantly, either containment buildings or sophisticated emergency core cooling systems.

This design also features continuous refueling. Pebbles are loaded continuously at top of the core, flow downward, and are discharged at bottom. The removed spheres are measured to determine the level of burnup and integrity, and are either sent to storage or returned to the core. The average sphere will pass through the core about 6 times before being discharged.[8] This process reduces the core inventory of two very troublesome short-lived radionuclides, including xenon-133 (which contributes to core instabilities) and iodine-131 (which is a major contributor to offsite doses in accidents).

Helium gas enters the core at 482 C and leaves the core at 900 C. The helium flows directly through a Brayton cycle turbine, which drives a generator. The direct coupling to a gas turbine (*i.e.*, without heat exchange to steam) would be the first of its kind. Because of the high temperature, direct coupling, and use of a gas turbine, Eskom estimates that the thermal efficiency of the unit would be 43 percent, significantly better than the 33 percent efficiency achieved by light water reactors. The helium is cooled though a series of water-cooled heat exchangers.

Eskom claims that the pebble bed modular reactor is "inherently safe," because the core cannot melt down if all helium coolant is lost. The reactor has many features that offer greater inherent safety than light water reactors. These features include low power density, large thermal mass, large negative temperature coefficient of reactivity, and small level of operational reactivity. Dr Edwin Lyman of the Nuclear Control Institute

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[7] Lyman, The Pebble-Bed Modular Reactor (PBMR): Safety Issues, Forum on Physics and Society, The American Physical Society, October 2001. Lyman notes that "this reactor design has a more negative fuel temperature coefficient (of reactivity) than LWRs, as the Doppler feedback is greater for the less-thermal neutron spectrum associated with a graphite moderator (which reduces) the risk of reactivity accidents for most scenarios, but increases the risk for accidents involving core overcooling."

[8] Sue Ion, David Nicholls, Regis Matzie, and Dieter Matzner, "Pebble Bed Modular Reactor—The First Generation IV Reactor To Be Constructed," World Nuclear Association, Annual Symposium, 2003.

notes that PBMR designers have taken credit for these features by weakening generally applicable safety standards in four main areas:

1. the use of a filtered, vented "confinement" building rather than large containment (can withstand explosive pressures of 9 atmospheres);
2. reducing the number of systems that must meet stringent quality control requirements to 15 percent (versus 40–50 percent for LWRs).
3. reducing the number of operating personnel; and
4. reducing the EPZ (emergency protection zone) from 16 kilometers to 400 meters.[9]

Eskom plans on-site storage capacity for 6 million spheres—all spent fuel on site for the life of the plant. The utility argues that discharged pebbles will retain their integrity for about one million years in a sub-surface repository without additional processing. There is no evidence that this claim has been confirmed by the very few nations with sub-surface repository efforts underway.

Assessment

Many of these features involve significant *theoretical* improvements on light water reactor design. The purported economic advantages of the PBMR stem, in large part, from the assumption that key safety requirements applicable to LWRs would not be necessary here.

The principal safety, reliability, and economic challenges associated with this reactor design include:

1. Quality control for the enormous number of microspheres.
2. Fuel performance and integrity, especially at temperatures above 1250 C.
3. Core stability, i.e., resistance to forming stagnant areas or "hot spots." Risk of fire, if air, water, or steam enters the graphite core.
4. Reliability of key components (e.g., valves, seals, bearings, core barrel, and first-of-its-kind gas turbine) in a very hot (900 C) environment with significant temperature differentials and thermal transients.
5. Resistance to unlikely but severe external threats, including earthquake, plane crash, flood, or terrorist attack.

The inherent safety of a pebble bed reactor is most dependent on the ability of the coated fuel microspheres to contain fission products over their irradiation lifetime. The microspheres themselves are about the size of a grain of sand; they are nearly twice the diameter after being coated with four layers. There is no doubt that these coatings provide resistance to migration of fission products from the fuel during normal operation. They have to; the barrier essentially takes the place of a steel pressure vessel in a light water reactor. Fission products released from the fuel are essentially released to the environment.

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[9] Op. cit., reference 7.

In reviewing Exelon's application to build a PBMR in the US, the US Nuclear Regulatory Commission staff submitted 123 detailed questions on fabrication, quality control, performance in the core, and ability to measure burnup reliably.[10] After Exelon pulled out, Farouk Eltawila, director of the NRC's Division of Systems Analysis and Regulatory Effectiveness, noted that "to test the fuel, it would take on the order of five to seven years."

The principal fuel challenges fall into several areas. First, there is a significant challenge in fabricating, and ensuring quality control, for the microspheres themselves. NRC staff note that the fuel kernel needs to be perfectly centered in the microsphere or the kernel will migrate out of the particle.[11] At that point, fission products are not contained. The kernels are so small, and the volume is so large (5 billion microspheres for an initial core load), that fabrication and quality control are major challenges. .[12]

It is also a challenge to fabricate the larger pebbles. Fifteen thousand microspheres are mixed with graphite and sintered (baked) into a large fuel pebble about the size of a tennis ball.

After this process was described in connection with the Exelon (US utility) application, Dr Dana Powers of the Advisory Committee on Reactor Safeguards (ACRS)[13] noted:

> The packing density of the fuel balls in the core is not really known. It is likely to vary with time and location in the core. They anticipate a 61% packing density versus the theoretical of 74% for uniformly sized spheres. I am not sure why they expect such a high density. Usually random packing of uniform spheres is less. It is clear that as the balls settle down through the core the packing density will vary. It might well be higher near the bottom than at the top near the point of injection of the recycled balls. There may be a severe control problem because of the varying density of the fuel balls.
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> The fuel density within the annulus varies both spatially and temporally as moving balls achieve various levels of imperfect packing density. The fuel balls do not have centers of gravity coincident with their geometric centers and may, in fact, have multiple, metastable equilibrium positions. Their motions are, then, chaotic, and inherently not predictable locally….I do not know whether the nonuniformity of ball positions and packing will be on sufficiently small scale that average temperatures are adequate.

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[10] *Op. cit.*, reference 10, Appendix 2.

[11] US Nuclear Regulatory Commission, "Request for Additional Information on Pebble Bed Modular Reactor Nuclear Fuel, Fuel Fabrication Quality Control Measures and Performance Monitoring Plans and PBMR Fuel Qualification Test Program," 27 June 2002.

[12] Op. cit., reference 7. Lyman notes that this is roughly three orders of magnitude more than the number of pellets needed to fuel the same amount of LWR capacity.

[13] The ACRS is the US Nuclear Regulatory Commission's advisory committee of top nuclear scientists.

These are some of the reasons that US Nuclear Regulatory Commission staff concluded that it would take five to seven years to qualify PBMR fuel. Over the irradiation lifetime, the coatings are vulnerable to internal pressures, thermal stresses caused by changes in temperature, irradiation damage to the coatings, and attack by specific isotopes at higher temperature.

For example, each uranium fission liberates more (about 13 percent) oxygen than its fission products can retain. The excess oxygen reacts with carbon in the first coating layer to form carbon monoxide (CO). For plutonium fissions that become very significant toward the end of pebble life, the problem is about five times more important (about 62 percent more oxygen than Pu fission products can retain). The CO can cause cracking or debonding of the coatings, and in the presence of a temperature differential, can move the uranium kernel from its central position. All of these factors increase the potential for CO to reach and attack the SiC layer, causing corrosion. When retained within the pellet, the CO is valuable for its ability to oxidize (and immobilize) some fission products (*e.g.*, rare earth elements) that might otherwise attack the SIC layer. It cannot contain some key fission products (most importantly radioactive silver and palladium) that become important with higher burnups and temperatures. Yields of radioactive silver and palladium are 25–50 times higher from plutonium than uranium fission.

Temperature, burnup, and core behavior are critical factors. While the average coolant exit temperature is 900 C, fuel temperature will be hotter and the core may contain “hot spots.” The design calls for high fuel burnup (95,000 thermal megawatt-days per metric ton) at high temperatures for extended periods of time.[14] The German AVR pebble bed reactor had numerous “hot spots” exceeding 1280 C, though the maximum predicted fuel temperature was 1150 C. This information forced Exelon (the US utility—then in design conversations with the US Nuclear Regulatory Commission) to raise its estimate of maximum fuel temperature for the PBMR from 1060 C to 1250 C.[15]

This issue is meaningful because the coatings on fuel pellets begin lose their effectiveness at 1250 C, where the risk is primarily palladium attack of the silicon carbide layer. This condition can lead to release of some fission products from the fuel, some of which can create maintenance and reliability problems. A recent report by the International Atomic Energy Commission notes:

> It is a known condition that the silver isotope, Ag-110*m*,[16] is released from the TRISO particle at high temperatures. The amount and level of influence this isotope has on the metallurgical and maintenance

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[14] This is three to four times the burnup achieved in the early operating history of light water reactors—33,000 MWd(t)/MTU for PWRs and 28,000 MWd(t)/BTU for BWRs. A series of improvements has led to burnups that can reach 62,000 MWd(t)/MTU.

[15] Op, cit., reference 7. US NRC, “Meeting with Exelon Generation Company and Other Interested Stakeholders Regarding the Pebble Bed Modular Reactor,” memo from T. King to A. Thadani, 23 July 2001, Attachment 5-b; IAEA, Fuel Performance and Fission Product Behavior in Gas Cooled Reactors, IAEA-TECDOC-978, November 1997, p 120.

[16] This radioisotope of silver is highly radioactive with a half-life of 250.4 days.

> consideration for the PCS components over the long period of plant operation has not yet been fully determined. Also, if operation is allowed to exceed a fuel temperature of 1250 C over an extended period of time, SiC [silicon carbide] coating thickness deterioration will occur due to palladium attack….Failure to understand the isotopic makeup, method of deposition on equipment and associated radiological dose levels for the PBMR and GT-MHR primary system(s) could result in increased failure of equipment, additional plant downtime, and larger than anticipated personnel exposures….Not knowing the extent of Ag-110*m* release as well as continuous high temperature operation and possible neutron streaming may significantly increase the maintenance considerations on the PCS components and cause deterioration in the life of the first stage turbine blades.[17]

If the silicon carbide layer remains largely intact, and temperatures are kept below 1250 C, most fission products are contained. Past experiments with current pebble bed fuel technology have found that less than 0.01% of the cesium-137 inventory is released at 1600 C. (While this may not pose off-site risks, the turbine maintenance and worker exposure issues could be very significant.) At somewhat higher temperatures, however, the silicon carbide layer loses its effectiveness. At 1800 C, 10% of Cs-137 inventory is released, about same fraction of the cesium inventory that would be released in a light water reactor meltdown.[18]

Ed Lyman cites a recent report by the Japanese Atomic Energy Research Institute found that “microspheres manufactured to identical specifications and irradiated under identical conditions exhibited drastically different fission product release behavior that could not be attributed to observed physical defects like cracking of the silicon carbide layer.” [19]

Following a two-day meeting of the Nuclear Regulatory Commission’s independent panel of reactor safety experts—the Advisory Committee on Reactor Safeguards—panel member Dana Powers of Sandia National Laboratories wrote, in part:

> Wear and damage to the fuel balls during normal operations will make ball motions all the more unpredictable and temporal and spatial variations in core power greater. Furthermore, the core is loosely coupled neutronically. This is a prescription for core instability akin to the kinds of instability encountered in boiling water reactors. The potential instability is made worse because control rods are not distributed within the local regions of the core, but are arrayed outside the core.
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> The South Africans have conducted some studies of anticipated transients without scram. They have found that with increasing burnup…the fuel has a decreasing

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[17] IAEA, Challenges to Commercialization of the Gas Turbine HTGR Plant, p 230.

[18] IAEA-TECDOC-978, p 137.

[19] Lyman, reference 7. K Minato, Fission Product Release Behavior of Individual Coated Fuel Particles for High Temperature Gas Cooled Reactors, Nuclear Technology 131, 2000.

> ability to sustain sudden energy inputs. They have made a regulatory decision that existing limits on fuel burnup are adequate protection against this vulnerability of coated particle fuel.
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> They have found that the shutdown system is not diverse. They find that the reactor can become critical as it cools if only one system is deployed. Both systems are required to keep the reactor shut down. They are asking the designers to re-examine the shutdown system. It is an open question whether a shutdown system outside the core will ever be acceptable.

The South African nuclear regulatory agency has provisionally concluded that risks of imperfect manufacture and quality control, uncertain core behavior, and poor burnup measurement will be addressed by limiting burnup to 95,000 thermal megawatt days per tonne. It is not clear that this will be sufficient. The US NRC conclusion that five to seven years of analysis and testing will be required is a sobering counterpoint.

The fuel recycling system needs to be able to detect pebbles that are near this limit, or otherwise not performing properly. Regulators need to be confident that pebbles will not form stagnant regions in the core, or hot spots, where burnup may exceed approved levels. They also need to be attentive to the possibility that pebbles nearing final burnup do not remain unexpectedly in the core beyond regulatory limits.

Graphite can oxidize at about 400 C if exposed to air, water, or steam. The reaction becomes self sustaining at 650 C, producing carbon monoxide and hydrogen.[20] Both are highly combustible gases. Water could enter the core through failure of the pressure boundary[21] and depressurization of the core with failure of a heat exchanger tube. The volume is likely to be modest, because water coolant pressure in the heat exchangers is lower than core pressure. Water would react with exposed uranium kernels. It would probably not react strongly with other core components. Air can enter the core through a variety of events, with a large pipe break the most likely precursor.[22] Air would react strongly with both exposed kernels and graphite. Air or water can also change the chemical properties of fission products in the primary circuit, with potential corrosive effects on the silicon carbide fuel surfaces and combustible gas generation.

While a graphite fire would not be hot enough to ignite the uranium microspheres, the graphite itself would be radioactive (from neutron activation of impurities and uranium released from defective microspheres). Carbon monoxide combustion could be significantly worse, damaging and dispersing the core and destroying the reactor confinement building.

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[20] Op. cit., reference 7.

[21] Although the design uses a helium turbine, not a steam turbine, the helium loop and generator are water-cooled, so in principle some mechanisms for limited water entry are conceivable.

[22] Op. cit., reference 7. A Kadak, “Advanced Reactor Technology Pebble Bed Project Progress Report,” MIT/INEEL, 2000.

Many components—including the high pressure turbine-compressor, low-pressure turbine-compressor, and turbine-generator—for the PBMR system will be the first of their kind. It will also be the first application for *magnetic bearings* on machines of this size in a *vertical* configuration with *radiologically contaminated* ultra dry *high temperature helium* as the working fluid. Axial bearings will also be severely tested in this environment.

In summary, pebble bed reactors have features that promise far greater inherent safety than light water reactors. But they also rely on very limited experience, particularly with TRISO fuel. If the fuel is manufactured less than perfectly, or if pebbles do not perform as expected inside the core, fuel temperatures may exceed safe levels and failures will occur.

To justify the absence of containment, Eskom must demonstrate that individual high burnup pebbles in parts of the core will not regularly exceed temperatures of 1250 C, where palladium attack begins. While these temperatures do not automatically pose a safety risk, they may result in release of isotopes that cause serious reliability and maintenance challenges, and impair the overall economic performance of the reactor. Sustained temperatures in the 1600–1800 C region create a larger problem because of the potential for significant offsite radiological exposures. Designers must show that no credible combination of events can lead to temperatures of this magnitude. The current design does not call for any in-core instrumentation. Many issues must be addressed by modeling.

PBMR Economics in South Africa and US

If the PBMR and the Pelindaba fuel fabrication facilities cost 10 billion Rand, the cost effectiveness of this technology is not difficult to evaluate. If entirely reflected in the cost of electricity, with no other costs, the delivered electricity price, depending on reliability, is at least ten and perhaps twenty times more than the price of electricity from current sources. This is true whether the project is built in South Africa or built in the US.

Eskom hopes that it will be able to build these plants for less than $1,000/kW, that they will operate at a 90 percent capacity factor, that fuel will be cheap, that maintenance requirements will be modest, and that containments will not be required. The first demonstration project is estimated to cost $15,150/kW, the reliability is unknown, the fuel will be expensive, maintenance may be significant, and containment may be required.

Eskom’s current average retail tariff is 2.3 cents/kWh. We can roughly guess at the delivered price of electricity from the demonstration reactor, assuming all costs are reflected in electric tariffs (rather than subsidized by taxpayers). At $15,150/kW, with a 50 percent capacity factor, without fuel or operation and maintenance charges, the cost of generation is 28.5 cents/kWh. Operations and maintenance charges and fuel inevitably add 1–2 cents/kWh. Busbar (at the reactor) costs for this demonstration project are more than a factor of ten higher than average retail tariffs. The overall impact on Eskom's average electricity tariff equates to a 3.9 percent overall increase, which is not enormous. Others may regard the performance assumption as pessimistic; at a 90 percent capacity factor, the cost is 15.8 cents/kWh plus fuel and O&M. These are also very high numbers. I know of no US utility that would undertake a similar project. When the design settles down, it would be desirable to do a much more sophisticated analysis, though precision will be impossible with large error bands on many key assumptions.

Central to long term prospects is the claim that pebble bed reactors do not require containment. Containments for (albeit generally much larger) US reactors cost $100–250 million. If a $100 million containment were required to protect a PBMR against accidents or external threats (floods, earthquake, or attack), the advertised eventual capital cost (about $110 million) would nearly double.

Several other cost and risk components had a role in Exelon's abandonment of the technology in the US. The cost of qualifying a new reactor design in the US has averaged $160 million for new Westinghouse and General Electric advanced water reactors. It is quite unlikely that the PBMR could be qualified more quickly or for less cost, given the large number of exemptions from current criteria that would be required.

In addition, in the event of a nuclear accident in any US reactor, each reactor owner is assessed, by law, a one-time retroactive premium of $96 million.[23] That may be a manageable number for investors in an existing 1000 MW reactor that perhaps cost $3 billion to construct. It is very nearly equal to the total construction cost ($110 million) that Eskom hopes PBMRs will achieve. Similarly, US nuclear operators pay a fixed fee of $3 million per reactor per year to the US Nuclear Regulatory Commission. This fee if imposed on a 110 MWe reactor is nearly equal to Eskom's estimate of long term fuel costs. Finally, following the September 11 terrorist attack, US reactors have substantially increased security personnel and perimeter monitoring. Most US reactors carry security staffs of 150 personnel, about twice the size of the staff Eskom estimates for all operations and maintenance, hugely increasing possible O&M costs. Economies of scale mitigate these issues for US reactor operators; they are significant barriers to any US utility contemplating PBMR technology.

These factors alone make US export prospects highly unlikely. Other advanced nuclear technologies, including advanced boiling and pressurized water reactors, have at least passed the licenseability test. They are less vulnerable to the other barriers, because unit size is greater. They are also more likely than the PBMR to benefit from federal research and development funds or special tax incentives.

The author works for an electric utility in the United States that was for many years one of the least expensive utilities in the nation. Average tariffs totaled 4.5 cents/kWh prior

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[23] This reflects an increase in the recently passed Energy Policy Act of 2005, which also (§608) treats multiple 100–300 MWe units at a single site, totaling not more than 1.3 GWe, as a single unit for purposes of liability limit and associated cost assessment.

to the west coast electricity crisis of 2000–2001. The utility has a strategic planning process underway to evaluate long run alternatives.

Assuming away all licensing costs, construction cost increases, and reliability risks, the cost of the demonstration reactor is nearly an order of magnitude more expensive than resources that we would pursue in the United States, including coal, wind, geothermal, biomass, and natural gas. In general, in the Pacific Northwest, those resources cost between 3–6 cents/kWh, depending on the technology and site characteristics (e.g., wind regime or proximity to transmission, gas pipelines, and coal beds).

In thinking about future generating resources, we consider many issues other than least cost. Many utilities in the US, Europe, and Asia are faced with a variety of long term challenges that involve changes in technology, markets, and regulation.

While the Northwest US has not restructured, we are not immune, and are therefore extremely attentive to risks—financial and otherwise—associated with new generating investments. The technologies of electric generation and transmission are changing quickly; the regulatory framework is not stable; markets for electricity and many of the products our larger customers provide can be volatile; and the investment community increasingly demands proof of short term investment recovery.

Technological risk is the possibility that some new resource will emerge as significantly cheaper than the resources in our current portfolio. If that happens, large customers will lobby for direct access to the resource and our investments in alternative technologies may be stranded, that is, paid for by residual customers. We are very attentive, as South Africans should be, to developments in energy efficiency, fuel cells, wind turbine technology, microturbines and other forms of distributed generation, photovoltaics, non-copper transmission technologies, gas turbine technology, LNG import capability, and coal and nuclear technologies. The PBMR is only one of many nuclear technologies under development.

Reliability risk is the possibility that an unproven new technology—whether pebble bed or not—will operate less reliability than other new resources. (One of our current reliability risks is counterparty credit risk, once unheard-of in the electric utility industry.) With specific regard to the proposed pebble bed project, we would at a bare minimum need to see extensive operating history to demonstrate that this design does not have the same sort of problems that led to the shutdown of both the Fort St Vrain and THTR-300 reactors. Of course, South African officials face the additional concern that urgent economic development goals and electrification would be set back by serious reliability problems.

Restructuring risk. Electric energy markets are being restructured—both inside South Africa and in many nations believed interested in PBMR technology. With wholesale competition, the ability of utilities (or independent power generators) to finance and recover costs from any capital intensive technologies, especially untested ones, is doubtful. With retail competition, the prospects are worse.

With wholesale competition, large industrial customers will demand very low electric prices, and can threaten to shift production elsewhere if they do not receive them. This has occurred in the US Pacific Northwest, where higher prices have shuttered most aluminum smelting, leaving higher costs for remaining customers.

The most important aspect of restructuring risk is the impact on Eskom's assumed export market. Utilities that might want a promising, but unproven, new energy resource may simply not be able to take the financial, reliability, market, and technological risks to acquire them. Eskom and South African officials should probably assume that this calculus ultimately convinced a very large US utility, Exelon, to drop out of the development consortium.

Market risks have already been covered to some degree in the discussions about technological and regulatory change. World commodity prices and electric energy prices make energy-intensive industries in both our regions highly volatile. We need to be especially careful that we do not make higher cost investments that drive these global industries to shift production (and electric demand) to another part of the world.

There may be no greater proof of all this than the extraordinary collapse—over the last three years—in the market capitalization of merchant electric generators. US merchant generators have lost more than $100 billion in capitalization over that period. Most are selling existing and partially completed units (generally gas-fired combined cycles), restructuring short term debt, and deferring or canceling new projects. That same picture affects merchant generation throughout the world. Utilities—even in unrestructured markets, with firm existing retail load service obligations to all customer classes—are not immune from the fallout. Financial markets demand that our incremental supply investments pay back the original investment much faster than either physical or traditional depreciation life.

The expectation of a high rate of return negatively affects prospects for PBMR exports in a number of ways. Reactors have high capital costs, and high return requirements especially penalize technologies with high initial costs. The PBMR is untested and unproven with respect to construction cost, regulatory risks, public acceptability, resistance to terrorism, reliability, maintenance cost, and economic life. All of these factors lead to higher risk premiums on debt and higher fractional equity requirements. While wind technology is capital intensive, the investment chunks are smaller, and the technological risks are minimal. Over the past four years, Seattle has invested in 175 MWe of wind capacity—perhaps the largest single commitment of any US utility. But we carefully ensure that this investment does not impair our financial health or the health of our customers.

Restructuring in South Africa

The South African electric grid is dominated by Eskom. The utility produces and distributes most of the electricity in South Africa. It also sells to more than 400 municipal distributors that set their own retail rates. Some of these distributors are quite small, and may not be financially viable. Eskom is also a retail service provider for most of the nation. Like many nations, South Africa has elected to de-monopolize, or restructure, its electric system. To some extent, the proposed restructuring has a number of internal conflicts.

Distribution system consolidation is not being done to make markets more competitive. It is instead designed to take advantage of the scope and scale economies of larger enterprises, and to ensure that these larger enterprises can provide important social services (e.g., electrification, free electricity to the poor, and cross-subsidization of some of these costs). It is entirely correct that more competitive retail and wholesale markets can undermine these long term goals.

The other restructuring proposals include privatizing about 30 percent of Eskom's generating capacity, consolidating the 400 distributors into six, and making all non-residential retail service above 11.4 average MWe competitive, with further retail access potentially available later.

In several important respects, the South African market is similar to that of the US Pacific Northwest. Our retail electric tariffs average 4.5 cents/kWh, about half that of the US as a whole. Like South Africa, this "competitive advantage" led to creation of a natural resource economy, dependent on cheap power to support many primary materials industries (including aluminum and steel) and food processing. We also have an important and growing high technology sector, concerned more with high reliability than low retail tariffs. About half the generation (and 75 percent of high voltage transmission) is owned—and sold to both local distribution utilities and directly to large industries—by the US federal government. Like South Africa, our grid is more radial (power plants to loads) than networked (all plants to all loads). Such grids are inherently harder (because of local and global market power in both generation and transmission) to make "competitive."

Also like South Africa, our system is dominated by an inexpensive incumbent. Virtually all parts of the United States with inexpensive, cost-based resources have resisted both state and federal efforts to restructure. We saw no economic advantage in selling—at a market price—inexpensive, cost-based electricity. We worried about the complexity of identifying and successfully regulating both the locational and global market power of both incumbent and new entrants. We hoped that new gas fired combined cycles would be built before the region faced dire shortage.

Most of those concerns were valid, but politically irrelevant, until the disastrous electricity crisis of 2000–2001. A combination of drought, high natural gas prices, poor market design, withholding of both gas pipeline and electric generation capacity, and an indifferent and unskilled federal regulator created an economic crisis that will last for more than a decade.

It is beyond the scope of this paper to assess South Africa's approach to industry restructuring. There are important lessons from the West Coast crisis, however, that bear consideration.

West Coast markets—both in California and in most of the rest of West—expected that virtually all new generating capacity built after the mid-1990s would be owned by non-utility "merchant" developers. The capacity would be built when wholesale prices rose to levels that would make this capacity profitable. Most analysts expected significantly volatility—with spikes to 10 cents/kWh for several hundred hours per year (about five times the "normal" level) during peak periods. Instead, price spikes reached several hundred times normal levels for several thousand hours in 2000–2001, not just in California's restructured markets but throughout the US West. A number of industries directly exposed to those prices have never recovered. Many utilities—both public and private—cannot now access traditional financial markets.

By nearly all accounts, there was not a physical shortage of either generation, electric transmission, or pipeline capacity, either in California or in western wholesale power markets. Some sub-regions were tight, and this created opportunities for various forms of withholding and price manipulation, some legal and some not. Despite enormous profit margins during the 2000–2001 crisis, the legal and political fallout from the Enron collapse has gravely wounded the once strong merchant power plant industry. The merchant sector—about 12 companies throughout the US—lost over 85 percent of market capitalization in 24 months, faces the immediate need to refinance over $60 billion in short-term bank debt, and is selling and abandoning more capacity than it is building.

There are several aspects of this history that are relevant to South Africa. In both the Northwest and South Africa, there are dominant suppliers of low cost power—Eskom and the federally owned Bonneville Power Administration. With privatization of 30 percent of Eskom's generation, the utility would remain the dominant wholesale provider. As in the Northwest, this inherent market power may be opposed by new entrants. They may worry about residual dominance in the wholesale market, and dominance in the retail market, even if that dominance involves sales of power to firm (i.e., non-contestable) retail customers at cost, under state-regulated tariffs. They seek an environment where all power is sold at a market price, where firm retail sales have no special priority access to transmission, without price caps at either the wholesale or retail level.

All of these desires are understandable. During periods of sufficiency, wholesale markets generally clear at the marginal fuel cost, with no return on capital investment. Merchants may require high prices during periods of impending scarcity, to make a rate of return on their capital investment. During the cyclic transitions from sufficiency to scarcity, prices can be extremely volatile, as they were throughout the western US in 2000–2001, which inevitably, though belatedly, led to price caps.

A number of analysts argue that the right combination of west-wide planning, resource adequacy standards, better retail price signals and market design, and prompt and effective federal regulation might have prevented the crisis. That combination is extremely tough to design and implement, and, in the end, has many characteristics in common with a fully regulated unrestructured industry. Today, the bulk of new capacity in the West is being built or financed (or both) by regulated public and private utilities rather than merchants. The notion that contestable retail loads, privatization of 30 percent of Eskom's portfolio, and an open transmission system will yield workably competitive wholesale markets, stable and more equitable retail tariffs, and new foreign investment is highly dubious.

In the Pacific Northwest, these policies (and we have two out of the three) would increase existing retail tariffs, increase the risk (and cost) of new supply additions, reduce reliability, and undermine investments in energy efficiency. The main reason is that the investment time horizon shrinks from the 30-year perspective of most vertically integrated utilities to something closer to 10–15 years. That translates into lower debt-equity rates, higher interest rates, and fear of speculative investments with near term rate impacts. These features would also diminish utility or merchant developer interest in technologies like the proposed pebble bed reactor. Some would also argue—probably correctly—that high and low cost utilities are stuck in that world whether restructuring in mandated or not, given technological changes in power generation, faster market cycles in both electricity and industry, and political pressures.

Restructuring can also conflict with many of the important public policy objectives that South African governments ask from the electric system—rural and urban electrification, inexpensive (or free) electricity for the poorest members of society, energy efficiency investments, collection of revenues to fund other municipal needs (fire, police, transport), and targeted economic development. It is not easy in restructured markets to allocate these costs without either undermining the viability of government enterprises (and encouraging bypass) or creating barriers to entry for new market participants. Given the importance of these investments to South Africa's future, it may be impossible to conclusively resolve this question.[24]

In evaluating the long term potential of the pebble bed reactor, and, most importantly, export potential, it pays to recognize that all the factors described above—regulatory changes, technological changes, and marketplace changes—are in force, in varying degree, throughout the developed and developing world. South Africa may be the only country that can build a new reactor technology, because of an unrestructured (so far) industry, very low retail electric rates, and the lack of competition from adjacent countries. A corollary point is that nations (and utilities) without those characteristics

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[24] For example, we have many industries in the Northwest located in rural areas where they are "the only game in town." Some sought market access when prices in wholesale markets were cheap, and most fought hard (with some success) to return to cost-based utility service when prices rose. For investor-owned utilities, these pressures are probably less effective than they are for governmentally-owned utilities whose boards are usually elected officials responsible for much more than electric service. This is a risk that Eskom must be prepared for.

will require many years of evidence before they can make a similar investment. Eskom must prove that pebble bed reactors can be built quickly and cheaply, without the need for containment, will operate at high reliability much longer than either Fort St Vrain or the THTR-300, are viable in restructured markets, and have not been outpaced by other energy technologies. This may take at least fifteen years.

That should be sobering to those who see rapid export potential following completion of a single demonstration project.

Other Issues: Proliferation Resistance and Radioactive Waste

All reactor technologies and fuel cycles present proliferation risks. Some technologies are far worse than others. Proliferation risk is a key factor is assessing the long term export potential of any new reactor design. The pebble bed reactor has both plusses and minuses on this count.

Several attributes are worth noting. The spent fuel from a pebble bed reactor will contain small amounts of plutonium. At low burnup, the quality of the plutonium is quite high, but the amounts are quite small. At full burnup, there is more plutonium, but it is relatively low in volume (5 kilograms per ton of fuel—about half the amount in light water reactor spent fuel) and it is encapsulated in carbon/silicon carbide spheres that would be difficult to reprocess. There is also 6 percent Pu-238, with high specific decay heat that makes weapons design somewhat more difficult, though the material is entirely weapons-usable.[25] Over time, this distinction disappears; Pu-238 has an 88-year half-life.

Denatured uranium spheres (usually 0.2–0.3 percent U-235) could be covertly inserted into the reactor and removed regularly, however, avoiding both the Pu-238 problem and reprocessing of silicon carbide/graphite spheres. Andrew Kadak at MIT has estimated that the number would need to be small (to avoid subcritical conditions in the core) and the process too time consuming (decades) for efficient weapons plutonium production. Obviously that conclusion depends on the number of pebble bed reactors a nation might devote to the task.

The more serious problem involves the enriched fuel. PBMR fuel is enriched to 9.6 percent U-235 (about twice the enrichment level of light water reactors). At that point, more than 90 percent of the separative work (enrichment) has been done to achieve weapons grade uranium. A given amount of enrichment capacity can therefore make an order of magnitude more bomb-grade uranium starting with 9.6 percent feedstock.

This is a very important problem. Unlike traditional gaseous diffusion enrichment plants, newer centrifuge plants can be small and nearly impossible to detect. Extensive technical support has been available on the black market, largely thanks to Pakistani scientist

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[25] Gun-type weapons cannot use plutonium, but implosion designs can use almost any grade of plutonium from high-quality weapons plutonium (6 percent Pu-240) to reactor-grade (25 percent Pu-240).

Adbul Q. Khan.[26] A small commercial gas centrifuge enrichment plant could serve 2–10 reactors. With a large PBMR market, thousands of facilities could be in operation worldwide.[27] Any single facility, using 9.6 percent U-235 as feedstock, could produce enough weapons grade U-235 for 875 nuclear weapons annually. Another problem is that uranium-235 bombs are remarkably simple to design and require no testing, unlike their plutonium cousins.

Reactor size and on-load refueling are also considerations. The smaller unit size of the pebble bed reactor makes export to small nations with no ability to digest the output of a 1,000-megawatt reactor. Many are potential proliferators, particularly in an environment where they fear the proliferation risks from adjacent nations.

The volume of spent fuel produced by a pebble bed reactor is more than 10 times greater than the volume of spent fuel produced by a similarly sized light water reactor, mainly because it contains so much graphite. The spent fuel storage costs would not be a major consideration for operators, but transport costs and volumes could be a factor. Repository storage costs are also a consideration. Eskom claims that the required repository storage volume for PBMR and LWR fuel would be similar, because LWR fuel would require overpacking but PBMR fuel would not. This claim is untested, and the combination of factors could be significant issues for some buyers.

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[26] Khan originally smuggled design drawings out of the Urenco gas centrifuge plant in The Netherlands in the late 1970s.

[27] The same risk applies to almost any scenario involving rapid worldwide growth of uranium-235 fueled reactors, including light water reactor technology.

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Experience:

Director of External Affairs Seattle City Light (1996–2005)
Director, Power Planning and Forecasting

Member of executive team responsible for developing and presenting utility policy on state and federal legislation, and regional debates, affecting the electric industry industry. Built and staffed coalition – Alliance of State Leaders (primarily state utility commissioners and public power from West and Southeast) – opposed to FERC's standard market design. Extensive work with Washington State Legislature, members of Congress, and Federal Energy Regulatory Commission; coordination with key groups, including Mayor, City Council, and City Attorney's office; Northwest states, regional Power Council, and trade associations. Represent Superintendent on the Board of the Washington Public Power Supply System (now Energy Northwest) and the board of the Pacific Northwest Utilities Conference Committee. Extensive public speaking and press relations responsibilities. Supervised group responsible for service area and sub-area load forecasting, portfolio analysis, development of integrated resource plan, and assessment of NW impacts from California market deregulation.

Director, Washington staff Northwest Power Planning Council (1995)

Provided lead staff support to Washington's two members on the Northwest Power Planning Council. Extensive coordination with Washington state agencies, including Energy Office, Department of Fisheries, Department of Wildlife, Governor's Office, and and Utilities and Transportation Commission.

Assistant and Acting Director Washington State Energy Office (1990–1995)

Served as assistant director for policy, program research, facility siting, and resources. Supervised staff of twenty seven. Served as Acting Director of 185 FTE agency for six months, following transition from Governor Gardner to Governor Lowry. Extensive involvement with State Legislature, cabinet agencies, Governor's Office, and members of the Congressional delegation. Provided lead staff support for development of Washington State Energy Strategy. Responsible for merging Energy Facilities Site Evaluation Council (EFSEC) into State Energy Office. Chaired task force on environmentally sound power exchanges for the Western Governors Association's Committee on Regional Electric Power Cooperation (CREPC).

Senior Associate MHB Technical Associates (1985–1990)

Lead economist for consulting firm providing technical assistance in litigation and utility regulatory cases, mainly involving prudence of utility power supply planning and investment decisions. Provided extensive expert testimony in regulatory proceedings throughout the US. Clients included Attorneys General for Texas, California, Michigan, New York; state regulatory agencies in Illinois, California, New Hampshire, Maine, and Vermont. Some work on reactor safety issues for organizations in California, France, Sweden, and Italy.

Executive Director International Project for Soft Energy Paths (1980–1985)
Energy Program Director Friends of the Earth

Founded and directed 501c3 (non-profit, tax deductible) organization that sponsored conferences, published extensively, and conducted research on potential for new and emerging renewable resources and energy efficiency improvements. Editor of bi-monthly publication. Extensive fund-raising and contract management experience. Consulting clients included the states of Victoria (Australia) and Lower Saxony (Germany), Amici della Terra, Canadian International Development Agency, US Environmental Protection Agency, US Congressional Office of Technology Assessment, Solar Energy Research Institute, US Department of Energy, President's Council on Environmental Quality, Atlantic Richfield Company, and Pacific Gas & Electric Company. Board or panel member for National Academy of Sciences, California Governor's Solar Cal Council, US Department of Energy's Energy Research Advisory Board, California Regulatory Reform Commission, Conference on the Fate of the Earth, and Californians for Nuclear Safeguards.

Special Advisor to Commissioner California Energy Commission (1976–1979)

Served as principal staff assistant to two members of the California Energy Commission, including the Chairman. Agency was responsible for developing a common approach to forecasting gas and electric demand, siting power plants, and setting efficiency standards on buildings and appliances. Served as administrative law judge in place of commissioner in evidentiary hearings; extensive interaction with State Legislature, Governor's Office, and other state agencies. Member, US delegation, International Atomic Energy Agency Conference on Nuclear Power and Its Fuel Cycle (Salzburg, Austria.)

Energy Program Director Friends of the Earth (1972–1976)

Responsible for developing energy policy position of national environmental organization. Extensive public speaking, expert testimony, and publications.

Education:

MBA Program	University of California, Berkeley	1989–1990
(did not complete, owing to relocation)		
AB (economics)	University of San Francisco	
	Bowdoin College	1974

Other:

Committee member, National Academy of Sciences. (Radioactive waste, subcommittee on socioeconomic issues associated with repository siting.)

Expert panel member, US Congress Office of Technology Assessment. (Nuclear non-proliferation, solar energy research and development, and energy conservation.)

Member, US delegation, International Atomic Energy Agency conference on nuclear fuel cycle.

Board member, Keystone Center.

Selected Publications

Rethinking Bonneville – What Role for Federal Hydro Resources in More Competitive Wholesale Markets? The Electricity Journal, March 2002.

Washington's Energy Strategy – An Invitation to Action. (Lead author on behalf of Governor's advisory committee), 1993.

A Comprehensive Review of NUREG 1150 – severe accident probabilities, consequences, and economics of incremental safety measures (with Steve Sholly), published by the Illinois Department of Nuclear Safety, 1988.

Plutonium Policy –1985 (with Walt Patterson), published by Brick House Press, 1985.

Nuclear Electricity and Alternatives in the US and Europe, published by Island Press in US and in Italy as *Caro Nucleaire* (1984).

What if Argentina Gets the Bomb (with Leonard Ross), op-ed published by New York Times and International Herald Tribune, 1982.

Socioeconomic Impacts of Nuclear Repository Siting and Fuel Cycle Policies (with members of a National Academy of Sciences panel), National Research Council, 1982.

End Use Forecasting of Electricity Demand (California Energy Commission memo on reduction in estimated demand growth from 7 to 3 percent per year associated with shift from econometric to engineering models), published by the US Senate Small Business Committee, 1979.

Editor and principal author, *Soft Energy Notes*. Bi-monthly journal published from 1980-1985 on technical and economic potential of renewable resources and energy efficiency. Compendium re-published as *Toward a Renewable Energy Future*, Brick House Press, 1984.