CHAPTER 12

ECONOMICS OF NEW NUCLEAR POWER AND PROLIFERATION RISKS IN A CARBON CONSTRAINED WORLD*

Jim Harding

INTRODUCTION

Climate change, growth in electricity demand, and persistently higher fossil fuel prices have reignited the debate over nuclear power and whether it is a safe or competitive resource inside the United States or internationally. Estimating the cost of a new U.S. reactor is a daunting exercise. The data base of advanced light water reactors underway or completed is small, almost entirely in Asia, and mostly accumulated in the 1990s—there has been significant real escalation in worldwide materials costs since 2002. The supply chain—key materials, components, skilled labor—is also extremely tight.

While the Japanese supply chain capacity is intact, U.S., Western European, and Russian industries have been largely moribund since the Three Mile Island and Chernobyl accidents. In the last several years, however, there has been a steep change. Utilities and vendors (nuclear system suppliers), both in the United States and abroad, have gone beyond computer models and extrapolation from Asian experience to real bids and real estimates.

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*A version of this article is available from *www.npec-web.org/Essays/20070600-Harding-EconomicsNewNuclearPower.pdf*.

Risk is reflected in contract terms, the allocation spread between vendors and utilities is often opaque. The thinly traded uranium spot market has been volatile. Electricity markets have also changed, with respect to the structure, regulation, finance, and cost and availability of competing and emerging technologies.

We do face inevitable controls on carbon emissions sometime in the future, with nuclear power obviously benefitting, whether these controls take the form of taxes or cap-and-trade approaches. One question is whether such benefits will help the nuclear industry enough.

To answer this question, we need to start by looking at probable construction or capital costs. This represents 80-90 percent of overall life-cycle cost. Other factors are important, including finance and capital cost recovery (debt, equity, taxes, and depreciation), net capital additions during operation, capacity factor, operating life, decommissioning cost, operations and maintenance, and fuel, including costs for waste management. This chapter presents two possible cases (high and low), and contrasts those results with estimates for other technologies under a range of possible carbon prices. It also offers some observations on possible worldwide growth rates for nuclear capacity, fuel cell requirements, and potential risks of weapons proliferation.

CAPITAL COST

To estimate the cost of new reactors in the United States, the best place to turn might be U.S. experience, but the data is old and not easy to interpret. Plants increased in cost at rates far exceeding general inflation.[1] The more plants we built, the more they cost, but that explanation is too simple—we had rising inflation and rising interest rates in the 1970s and 1980s, supply chain imbalances for key components and skilled labor, state and federal regulatory issues, design-as-you-build construction, siting and financing challenges, growing public opposition, and declining rates of electricity growth (see Figure 1).

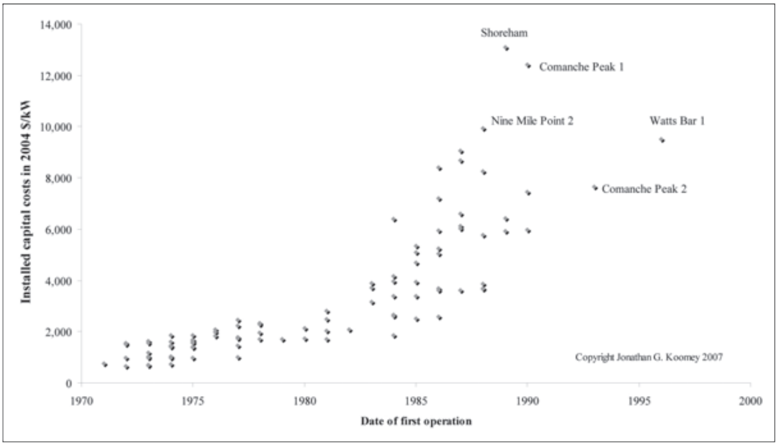

Figure 1. Capital Costs of U.S. Reactors Built between 1970 and 2000.

In the recent past, industry and government estimates for nuclear construction ranged from $1,500 to $2,100/kilowatt (kW), expressed in various year dollars.[2] Recent bids and industry estimates, however, are far higher. In June 2009, the Ontario Power Authority declined two bids for two reactors from Atomic Energy of Canada (AECL) ($10,800/ kW) and Areva ($7,375/kW). The latter was "non-conforming," which presumably means that substantial risk of delay and cost escalation was placed on the utility. The Electricity Supply Commission of South Africa also declined to accept bids this year, the lowest of which was reportedly $6000/kW.

A variety of studies have been conducted in recent years to test past government and industry estimates. In 2003, an MIT study rejected lower cost estimates as based on software estimates, rather than real construction experience, and for failing to include key owners' costs, including land, construction oversight, and project contingencies. The report instead relied on estimates for recently completed (1993-2002) advanced light water reactors in Japan and South Korea. Overnight costs (a common convention), not including either escalation or interest during construction, are shown in Figure 2 at date of commercial operation in real 2002 dollars.[3] We have not included the South Korean units in computing the average because of lower South Korean labor rates, though the average exclusive of these units is provided in Figure 2. MIT, however, assumed that the Asian experience could be directly imported to the United States, and that there would be zero real cost escalation or delay for U.S. reactors.

Plant	**Megawatts**	**Date of Commercial Operation (COD)**	***Yen@COD***	**2002$s/kW**	**2007$s/kW**
Onagawa 3	825	Jan-02	3.14E+11	2409	3332
Genkai 3	1180	Feb-94	3.99E+11	2643	3656
Genkai 4	1180	Jul-97	3.24E+11	1960	2711
KK3	1000	Jan-93	3.25E+11	2615	3617
KK4	1000	Jan-94	3.33E+11	2609	3608
KK6	1356	Jan-96	4.18E+11	2290	3167
KK7	1356	Jan-97	3.67E+11	1957	2707
Y5	1000	Jan-04	NA	1700	2352
Y6	1000	Jan-05	NA	1656	2290
Average				2354	3257

Figure 2. MIT Cost Estimates Based on Light Water Reactors in Japan and South Korea.

The chart in Figure 3 provided by the Electric Power Research Institute shows recent cost trends for large U.S.-engineered projects. After a number of years with little or no real escalation in costs, the curve has steepened to roughly 4 percent real escalation per year, mainly driven by higher costs for steel, copper, concrete, and other materials.

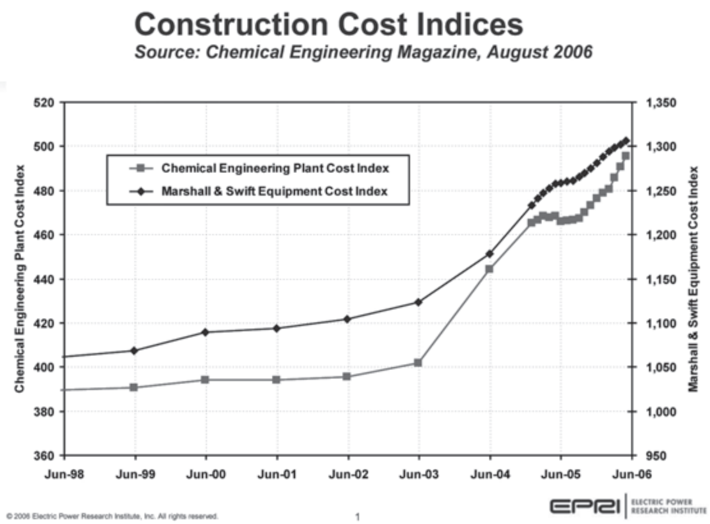

Figure 3. Cost Trends for Recent U.S.-Engineered Projects.

Some utilities believe that other indices (e.g., "heavy construction") are more appropriate though yielding higher escalation rates (e.g., American Electric Power at 7.8 percent real through 2007).[4] See Figure 4.

Commodity/Construction Material	Avg. Annual Escalation from 1986 to 2003	Avg. Annual Escalation from December 2003 to April 2007	Last 40 Mo. Escalation at Ratio of Recent Historical Avg.
Nickel	3.8%	60.3%	15.9x
Copper	3.3%	69.2%	21x
Cement	2.7%	11.6%	4.3x
Iron & Steel	1.2%	19.6%	16.3x
Heavy construction	2.2%	10.5%	4.8x

Figure 4. Escalation Rates Based on Heavy Construction.

Cambridge Energy Research Associates (CERA) has also begun to compile a power plant capital cost index based on current worldwide transactions by utilities and vendors, as shown in Figure 5. A Reuters press report indicated that the nuclear cost increase estimated by CERA was 185 percent (i.e., nearly trebling) from 2000 to 2008, or roughly 16 percent per year in nominal dollars. Escalation has been negative, however, for the past 18 months.

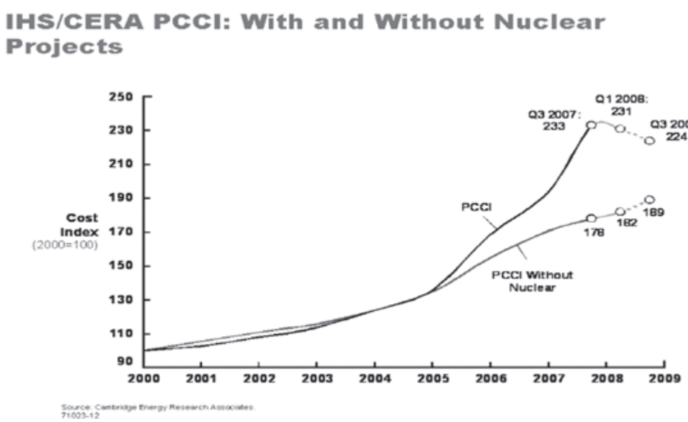

Figure 5. CERA's Worldwide Power Plant Capital Cost Index.

The reasons for real cost escalation are extremely complex and difficult to predict. Some key factors include volatile materials prices, mostly traded in international markets; changing value of the dollar; strong demand for construction materials, especially in China and India; supply-chain imbalances and possible scarcity pricing for suppliers, sub-suppliers, engineering-procurement-contracting (EPC) firms, and skilled labor; rising contingency insurance premiums, and/or hedging costs throughout the supply-chain; and poor or unsophisticated cost estimates from 2000-04.

In the 1970s, the usual utility practice was to get a bid for a new nuclear steam supply system (NSSS) from a vendor (then General Electric, Westinghouse, Combustion Engineering, Babcock & Wilcox, or General Atomics). The utility would typically hire an architect-engineer (e.g., Bechtel) to manage engineering design, procurement, and contracting. The current approach is different; utilities expect the vendors to hire architect-engineers and manage construction. Initially, vendors did this in the 1960s, delivering a turnkey (ready for operation) unit. While the projects being proposed today are turnkey in the sense that construction and procurement are managed by vendors instead of the utility, they are not turnkey in terms of being built for an initially agreed fixed price.

While some vendors may be willing to bid some parts of the project at a fixed price, there is little evidence of vendors being willing to bid most of the project cost at a fixed price, or as a loss leader (sold at below cost to attract future business). Bids typically include elements that are "fixed" in cost; "firm," meaning indexed to various escalators; and "variable," meaning passed through at whatever the cost turns out to be. The range in cost estimates may be substantially explained by different levels of escalation risk borne by the vendor. Vendors' bids are often not directly comparable; some may include some owners' costs (e.g., cooling towers), while others do not. Greenfield (industrial project starting from scratch on virgin land) sites are likely to be more expensive than brownfield (industrial project involving conversion of a no-longer-in-use factility), and often require substantial investments in dedicated transmission. A substantial number of recent cost estimates involve confidentiality agreements that make a thorough outside assessment and comparative analysis difficult, if not impossible.

Final completion cost is usually expressed in "mixed current dollars" at the date of commercial operation. Mixed current dollars is an unusual term. Investments are made in then current dollars, but they accrue interest from that date forward until commercial operation begins. So an investment in 2008 is in 2008 dollars, but it accumulates interest until the plant is complete. An investment in 2012 on the same plant is in 2012 dollars, but it was exposed to inflation and real escalation from 2008 to 2012, producing a sum which may be higher or lower than a 2008 investment with interest. When the plant enters service, its completion cost is the sum of early investments with interest and little inflation or escalation, plus later investments with inflation and escalation, but little interest. In the rare (if not unimaginable) case that real escalation and real interest costs are exactly zero, overnight cost equals final completion cost.

It is also possible and highly desirable, though uncommon, to state completion cost in real (discounted) constant year dollars, including real interest and real escalation during construction. This makes it possible to directly compare project estimates for completion in 2015 with those scheduled for 2020, which is otherwise a laborious task, mainly involving deconstructing cash flows, assumptions regarding interest during construction, real escalation during construction, and project contingencies.

Florida Power & Light (FP&L) recently filed testimony before the state Public Service Commission, with costs derived from the Tennessee Valley Authority's (TVA) 2005 estimate for new units at the nuclear plant site in Bellefonte, Alabama. The vendor's engineering-procurement-contracting cost estimate for Bellefonte was given as $1611/kW in 2004 dollars, not including owners' costs. FP&L escalated the Bellefonte values using a range of escalation rates and contingency assumptions, plus owners' costs.

The utility's overnight cost estimates, in 2007 dollars, included a low case estimate of $3108/kW, mid-case of $3600/kW, and high case of $4540/kW. The FP&L analysis includes $200-$250/kW in transmission integration (hooking into the regional grid) costs (see Figure 6).

Source	$/kW overnight cost
Keystone (2007)	2950
Constellation Energy (2008)	3500-4500
Eskom (South Africa, 2009)	6000
FP&L (2008)	3108-3600-4540
Duke Energy (2008)	5000

Figure 6. Transmission Integration Costs.

Figure 7 shows real and expected escalation rates used by various organizations for recent past escalation, and for estimating future escalation.

Source	2004-2007 nominal	2004-2007 real	Future	Basis
Keystone	6.0 %	3.3%	0-3.3% real	Chemical plant
AEP	10.5 %	7.8%	NA	Heavy construction
CERA	16 %	13.3%	NA	Utility generation
FP&L	10.7-20.7 %	8-18%	1-2% real	Construction indices

Figure 7. Overnight Cost (2007 Dollars, Including Real Escalation/Interest During Construction).

In general, there is little reason to think that escalation rates for nuclear power would be any lower, and could be substantially higher than for other generating resources. Long construction periods and high capital intensity exacerbate this problem. There is a spectacular difference between zero, 4 percent, and 14 percent per year cost escalation, especially for long lead time projects. See figures 8 and 9.

Real escalation	0%/year	4%/year	8%/year	14%/year
Medium case	$4050/kW	$5400/kW	$7130/kW	$9050/kW
High case	$4540/kW	$6050/kW	$8000/kW	$10150/kW

Figure 8. Levelized Cost of Energy (2007 Cents/Kwh, Including Interest and Operating Costs).[5]

Real escalation	0%/year	4%/year	8%/year	14%/year
Medium case	10.7	13.4	16.9	20.7
High case	11.7	14.7	18.6	23.0

Figure 9. Real Escalation Percentages by Year.

CONSTRUCTION TIME, LEAD TIME, AND DATE OF COMPLETION

It is very difficult to determine whether real cost escalation will continue into the future, and it clearly affects all generating options, though it is most acute for capital intensive resources. As described earlier, nuclear power faces some specific supply-chain challenges that argue against a low number. Twenty years ago, the United States had about 400 suppliers and 900 nuclear or N-stamp certificate holders (subsuppliers) licensed by the American Society of Mechanical Engineers. The numbers today are 80 and 200.[6]

Worldwide forging capacity for pressure vessels, steam generators, and pressurizers is limited to two qualified companies—Japan Steel Works and Creusot Forge—and the reactors' builders will be competing with each other as well as with simultaneous demand for new refinery equipment. Japan Steel Works prices have increased by 12 percent in 6 months, with a new 30 percent down payment requirement.[7]

Other long lead-time components, including reactor cooling pumps, diesel generators, and control and instrumentation equipment have 6-year manufacturing and procurement requirements. In the near term, reliance on foreign manufacturing capacity could complicate construction and licensing. Nuclear Regulatory Commission (NRC) Chairman Dale Klein recently indicated that reliance on foreign suppliers would require more time for quality control inspections to ensure that substandard materials are not incorporated in U.S. plants.[8]

Skilled labor and experienced contractors present another problem. A recent study by GE-Toshiba identified a potential shortage of craft labor within a 400-

mile radius of the Bellefonte site, forcing the adoption of a longer construction schedule.[9] Other sources have pointed to the potential for skilled labor shortages if nuclear construction expands.[10]

Several of these problems have clearly surfaced at the Olkiluoto 3 site in Finland, where the French vendor Areva is building a 1,600 megawatt advanced European pressurized reactor (EPR). Areva originally estimated a 4-year construction period, but the plant has fallen 18 months behind schedule, and is substantially over budget. Analysts estimate that Areva's share of the loss on the turnkey contract will exceed $1 billion. Concrete poured for the foundation of the nuclear island was found to be more porous than the Finnish regulator would accept. Hot and cold legs of the reactor cooling system required reforging.

At a recent conference in Nice, Areva official Luc Oursel indicated that the company had underestimated what it would take to reactivate the global supply chain for a new nuclear plant. In particular, they were not "100 percent assured to have a good quality of supply," were not sufficiently familiar with the "specific regulatory context" in Finland, and began building without a complete design. Some 1,360 workers from 28 different nations are now at work at the site. The project manager for STUK, the Finnish regulator, added that "a complete design would be the ideal. But I don't think there's a vendor in the world who would do that before knowing whether they would get a contract. That's real life."[11]

The industry believes that standardization and "learning curves," coupled with resolving supply chain imbalances, will drive costs lower over time. But there are chicken-and-egg problems with this conclusion. Utilities may not order new plants and equipment if capacity is limited and costs are uncertain. Suppliers may not expand production capacity if orders are not immediately forthcoming. As suggested in the comment above, vendors may not be willing to complete engineering designs before contracts are awarded. Moreover, given the structure of the U.S. utility industry, learning curves may be hard to achieve, with different utilities in different parts of the country considering standardized but different reactor designs.

The French experience most strongly suggests that rapid construction is best achieved with one utility ordering one basic design at a steady rate, keeping vendors, subsuppliers, and construction crews operating near capacity and able to move smoothly from one project to the next.[12] That model of single government vendor, coordinated procurement, and single government utility is rare, if not unique and unavailable, in today's world.

Market and regulatory issues also play a role. In most restructured U.S. markets, utilities would not be able to "rate base" new nuclear generation, and would instead need to rely on sales in the wholesale market, where trades are often thin, unpredictable, and short in duration. Plants built in that environment would have a very unfavorable financing structure (e.g., 70 percent equity and 30 percent debt).

In more traditional markets, utilities will probably be required to prepare integrated resource plans, comparing all supply and demand side options, including utility and nonutility owned generation. The utility might then be required to run a competitive procurement process that could include utility-owned nuclear generation. Regulators will probably consider cost caps, and/or annual prudence reviews, as a condition of final approval. Some states may take a more supportive and proactive position, for example by permitting utilities to recover construction work in rate base despite near-term rate impacts.[13] In other states, charging costs to customers before the plant came into service would not be acceptable or consistent with current law.[14]

The MIT study assumed a financial structure of 50 percent debt (at 8 percent) and 50 percent equity (at 15 percent), including a modest equity risk premium (3 percent) for a new nuclear plant. Those assumptions are reasonable for an investor-owned utility able to access rate base. However, a recent report by Moody's indicates that virtually any utility planning to build a large nuclear plant would almost inevitably face a rating downgrade, increasing the cost of money during construction.[15]

The 2005 National Energy Policy Act included several subsidies to jump start low carbon emission resources, the most important of which involved federal loan guarantees. In May 2007, the Department of Energy (DoE) released a second draft of its loan guarantee rules. The draft rule provides for the federal government to guarantee 90 percent of the debt, so long as the amount does not exceed 80 percent of the total project cost. DoE also indicated that it was considering a significant minimum equity stake on the part of any developer, and that guarantees should be limited to five projects that use the same technology.

Three features of the program diminish its value: first, the government-backed debt cannot be stripped from the total debt; second, the nonguaranteed fraction of debt is subordinated to the covered fraction; and finally, DoE's fiscal 2008 budget proposes $9 billion in total loan guarantees of which $4 billion would be allocated to nuclear plants and coal with carbon sequestration. A banker contacted by the trade journal *Nucleonics Week* commented that the first two features devalue the debt from a possible AAA rating to "single B or double D."[16] Four billion dollars in loan guarantees also might cover only one or two new units.

In general, most prospective nuclear builders regard these provisions as potentially valuable, but uncertain, unlikely to be sustained over the long term, and not a tipping point for a nuclear investment. Finally, it is important to emphasize that government subsidies do not reduce the cost of nuclear power; they spread risk and cost to taxpayers and reduce prices to ratepayers.

Interest during construction depends on several key factors—duration of construction, shape of outlays, the debt to equity ratio, and returns on both debt and equity. The U.S. Energy Information Administration assumes a 6-year construction period for a new reactor. Some vendors believe it can be done in 4 years. The MIT base case was 5 years.

OPERATING, MAINTENANCE, AND FUEL COSTS

One of the most important parameters affecting lifecycle cost is reactor performance, or capacity factor. U.S. average nuclear capacity factors have increased from below 60 percent during most of the 1980s to nearly 90 percent in the post-2000 period.[17] Some of the increase is attributable to changes in technical specifications for equipment to operate within a wider range and to higher fuel enrichments. The first reduces the number of equipment related reactor trips and shutdowns. The second reduces the number of refueling outages. It may also be true that outages are more frequent in early years ("teething") and later years ("aging"). A reasonable lifetime range for future units is 75 to 85 percent.

Advanced light water reactors may have lower operations and maintenance costs than current units, based on the use of more passive safety systems. Including capital additions (essentially capitalized operations and maintenance), the current U.S. average is about $100-$120/kW-year, inclusive of administrative and general (essentially pension and insurance) costs. There is no recent history of real escalation in the value, and it is probably appropriate for both a low and high estimate.

Nuclear fuel costs have many components—uranium mining and milling, conversion to UF6, enrichment, reconversion, fuel fabrication, shipping costs, interest costs on fuel in inventory, and spent fuel management and disposition. The 2003 MIT study calculated a 5 mill (half a cent) per kW hour cost for all these steps, based on then-current uranium prices of $13.60/pound (lb). Spot market prices for uranium in early June 2007 were $135/lb, tripling since October 2006. The reasons for the price increase are somewhat complicated. They are now about $44/lb.

Uranium prices have been volatile over the past 3 decades. Real spot prices almost sextupled from 1973 to 1976, then dropped steeply through 2002, but have risen dramatically since that time. The problem is not declining physical supplies of uranium, cost of production, or growth in demand for nuclear fuel. The key problem is that much uranium demand over the past 2 decades has been met by inexpensive "secondary supplies," including surplus inventories from cancelled or shut-down units (1980s-1990s) in the United

States, Western Europe, and Russia; purchase of surplus Russian and U.S. Government stockpiles (mid-1990s); and diluting highly enriched uranium from surplus Russian nuclear weapons (1998-2013) with natural uranium.

Worldwide uranium production is about 60 percent of current uranium demand.[18] Existing spot uranium prices clearly support enhanced production, both in the United States and abroad, but lead times for new mines are long. The same situation applies to enrichment. Uranium mining expansion will need to be better than 1980s rates of expansion to meet 2015 demands, particularly with limited enrichment capacity worldwide.

Nuclear plant owners and utility customers are not currently facing strikingly higher fuel prices, mainly because current contracts were written during a period of surplus and include price ceilings. The same basic situation applies to enrichment cost and supply. Most current long-term contracts expire by 2012, and secondary supplies decline rapidly during that period. The price ceilings in long-term contracts also mean that those parties that might pursue new mines or enrichment plants have not benefited substantially from price signals in the spot market. It also means that utilities with uranium and enrichment contracts largely expiring in 2012-13 must enter the market this year or next to ensure adequate supplies in the future.

Assuming current prices for uranium and enrichment ($44/lb and $160/kgSWU), nuclear fuel cycle costs are about twice the amount calculated in the MIT analysis. While these price increases are dramatic, they do not justify reprocessing to recover plutonium from spent fuel for subsequent recycling as mixed oxide fuel (MOx) in light water reactors. The

2003 MIT study compared this choice with $13.60/lb uranium and $100/kgSWU enrichment prices. This yielded a 5 mill/kWh fuel price; using very conservative estimates for reprocessing and mixed oxide fuel fabrication yielded closed cycle fuel costs that were more than a factor of four higher. With $2000/ton reprocessing and $1500/kg mixed oxide fuel prices, a closed fuel cycle costs about twice the MIT value, or 4.3 cents/kWh.

CARBON CONSTRAINTS

With carbon constraints (specified as taxes or a cap-and-trade approach), nuclear power's competitive position improves. Standard & Poor's (S&P) recently released an economic analysis on the sensitivity of electricity generation technologies to carbon controls.[19] Only plant—rather than full fuel cycle—emissions were considered. The base case capital cost estimate for nuclear power was $4000/kW, which is generally in line with the values calculated here. Operations and maintenance (O&M) costs were in line with the values calculated here, but the nuclear fuel price was estimated at 0.7 cents/kWh—roughly 2-3 times too low. The price of natural gas was estimated at $7 per million British thermal unit (BTU).

Coal price estimates ranged from $1-$1.80 per million BTU for Wyoming and eastern coal respectively. Direct comparison with the values calculated here can be somewhat tricky, mainly because S&P does not show all financial assumptions (see Figure 10). The first row of bold numbers shows internal costs, without carbon capture or taxes. The second bold row shows costs with carbon capture and sequestration, and the final bold row shows costs with carbon credits or taxes of \$10-\$30/ton. As shown, nuclear power has only a modest advantage over coal (either pulverized or integrated gasification combined cycle [IGCC]) if carbon sequestration is required. It is significantly less competitive with carbon taxes or credits, if they are available in a range of \$10-\$30/ton of CO_2.

	Pulverized Coal	Gas CCCT	Western IGCC	Wind	Nuclear
Capital Cost (\$/kW)	2438	700	2925	1700	4000
Capacity Factor (%)	85	65	80	33	85
Fixed O&M (\$/kW-yr)	45	20	60	25	100
TonsCO2/MWh	0.87	0.37	0.94	NA	NA
Total cost (cents/kWh)	5.8	6.8	6.5	7.1	8.9-9.8[i]
Carbon Capture					
Capital Cost (\$/kW)	940	470	450	NA	NA
Energy penalty (%)	25	13	15	NA	NA
TonsCO2/MWh	0.09	0.04	0.09	NA	NA
Cost for capture and sequestration (cents/kWh)	6.2	2.8	3.6	NA	NA
Total cost (cents/kWh)	12.0	9.6	10.1	7.1	8.9-9.8
Total cost with carbon credits at \$10-30/ton	6.2-7.9	7-7.7	6.5-8.4	7.1	8.9-9.8

[i]. The higher value uses the fuel cost estimate provided above.

Figure 10. Comparison of Prices of Various Energy Sources.

Standard & Poor estimates for carbon capture appear pessimistic, and for pulverized coal, unrealistic. A recent International Energy Agency (IEA) analysis of new and existing energy technologies found incremental costs ranging from 2-3 cents/kWh, depending on the fuel (natural gas or coal) and technology used. The IEA values for gas and coal IGCC are only slightly below S&P estimates, while the values for pulverized coal are less than half the S&P estimate, driven mainly by a much lower estimate for efficiency loss. The reasoning behind the pulverized coal analysis is not clear.

Technologies under development might reduce these values to 1.5-2.25 cents/kWh, not including CO_2 transportation and storage (both relatively minor elements). They also do not take credit for possible beneficial use of the carbon dioxide in enhanced oil recovery. For example, at 0.1-0.5 metric tons of oil per ton of CO_2 injected, the credit would range from $30 to $160 per ton of CO_2, substantially diminishing, and perhaps offsetting entirely, costs for capture, transport, and storage.[20] Finally, if carbon is taxed or credits are available for $10-30/ton in national or international markets, coal and gas plant developers may pursue projects without carbon sequestration. This implies that other carbon mitigation options—throughout the economy—may be cheaper than sequestration.

It is important to add that costs for all these technologies can vary widely from nation to nation based on market structure, degree of government involvement (e.g., subsidies or nationalized grid), and access to gas or wind resources. In summary, at foreseeable levels of carbon taxes or cap-and-trade credit approaches ($10-30 per ton of CO_2), nuclear power may be advantaged, but not to the point where it is a compelling choice.

Princeton scientists Stephen Pacala and Rob Socolow have proposed the concept of "stabilization wedges" for coping with the climate change problem for the next 50 years with current technologies.[21] Pacala and Socolow proposed 15 possible wedges covering all sectors of the economy, including agriculture, deforestation, electricity generation, transport efficiency, and fuel supply, among others. Full implementation of seven wedges—or a larger number of partial wedges—would be needed to stabilize atmospheric concentrations of CO_2 at 500 parts per million—a little less than twice pre-industrial levels (280 ppm). One of the possible wedges involved worldwide expansion of nuclear power, essentially doubling current capacity from 370 gigawatts (GWe) to 700 GWe over the 50-year period.

The authors assumed that this capacity would displace efficient coal generation. Over the same period of time, essentially all existing reactors will be retired, so that 1,070 GWe must be built to achieve a wedge. A 42-year projection expressed in megawatts (one gigawatt equals 1,000 megawatts) is shown in Figure 11.

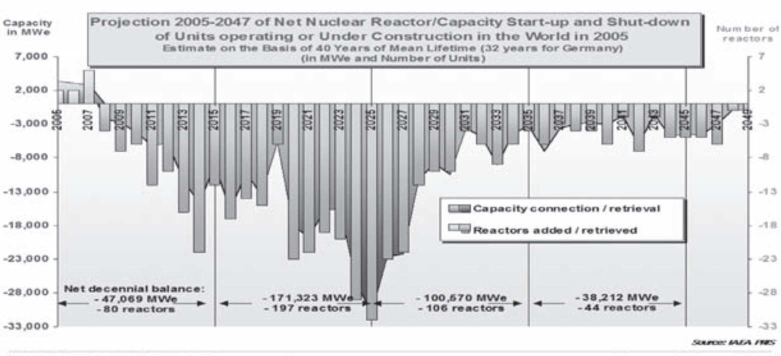

Figure 11. Required Nuclear Reactors to Support Full-Spectrum CO_2 Reduction.

A number of nuclear fuel cycle facilities would either be required, or need to be considered.[22]

• 23 new centrifuge enrichment plants the size of the proposed American Centrifuge Plant in Piketon, Ohio;

• 18 new fuel fabrication plants;

• 10 new repositories the size of the proposed Yucca Mountain facility in Nevada; and,

• 36 new spent fuel reprocessing plants, if all spent fuel were reprocessed.

In addition, if fuel is reprocessed and fabricated into a mixed oxide for use in reactors, a large number of mixed oxide fuel fabrication facilities would be required. The design capacity of the UK Sellafield mixed oxide fuel fabrication plant was 120 tons of heavy metal per year, but 40 tons/year appears to the achievable limit. Potentially, several hundred Sellafield-sized mixed oxide fabrication plants would be required to support extensive worldwide use of plutonium fuel.[23]

Pacala and Socolow did not directly examine the question of whether 1,070 GWe of nuclear capacity and associated fuel cycle facilities could be built over 50 years. National and international forecasts of future nuclear capacity typically do not go beyond existing utility planning horizons of 10-20 years.

A recent analysis by the IEA (*World Energy Outlook*, 2006) estimates that global nuclear capacity in their "Reference" scenario would grow from current levels (about 370 GWe) to 415 GWe by 2030. This implies a net rate of growth of about 2 GWe per year, and is based on optimistic capital ($2000-$2500/kW construction cost) availability and lifecycle costs (4.9-5.7 cents/kWh). It assumes that existing government policies remain largely unchanged. (See Figure 12.)

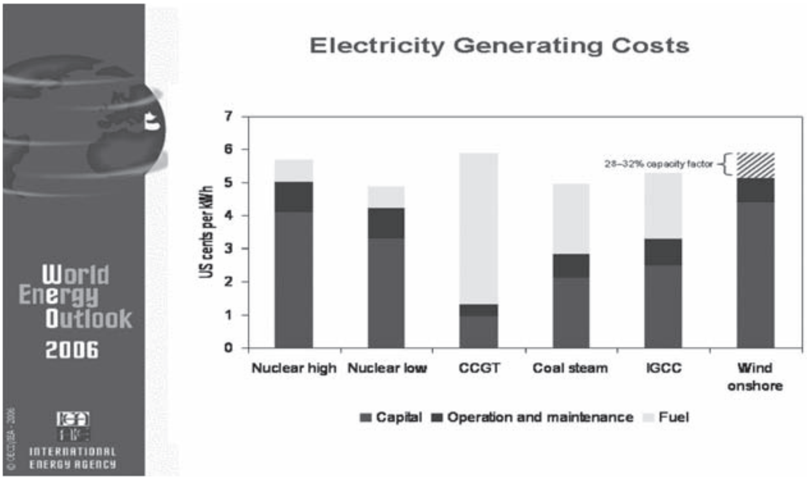

Figure 12. Projected Electrical Generating Costs by Source under Present Policies.

The *World Energy Outlook* also includes an "Alternative Policy" scenario, with widespread efforts to combat global warming and encourage new nuclear construction. This leads to a global capacity of 519 GWe in 2030, for a net growth rate of about 6.5 GWe per year. As Figure 13 shows, growth rates much higher than 2-6.5 GWe per year have been sustained in the past. The circumstances were different—higher estimated rates of growth in demand, substantial margin between estimated cost of nuclear power and alternatives (mainly limited to coal and oil at that time), and greater industrial capacity. It is also not clear that the rate of peak additions was sustainable at the time. Additions since 1996 have been at less than 0.5 GWe per year.

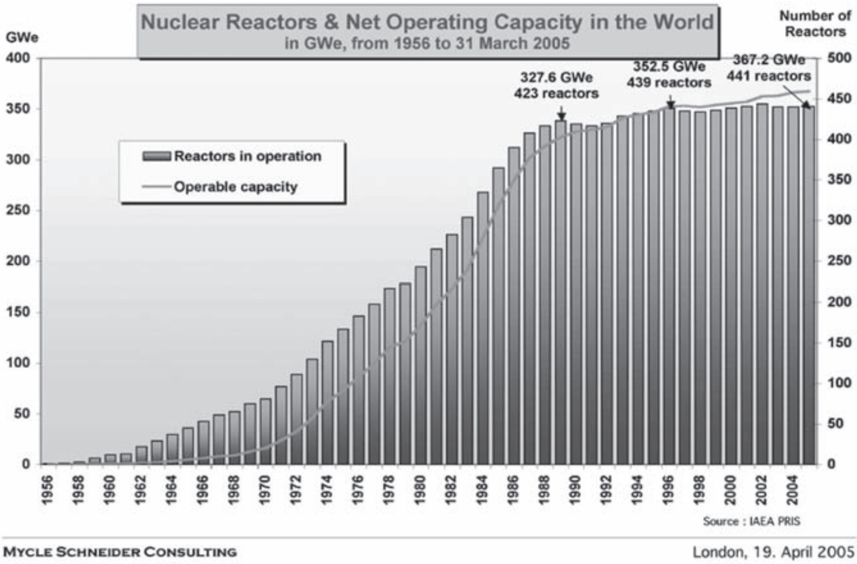

Figure 13. Growth of World Nuclear Energy Capacity, 1956-2005.

IEA's *World Energy Outlook* 2006 acknowledges several important challenges facing any nuclear scale-up: "The expansion of nuclear capacity may, however, face several constraints, such as limits to global capacity to build major components of nuclear power plants, for example pressure vessels and valves, especially for very large reactors. Similar to other industries, short-term constraints that may limit new construction include the cost of raw materials, the difficulty of finding engineering, procurement, and construction contractors and the shortage of key personnel."

In the IEA Reference scenario, nuclear capacity increases at 0.7 percent per year, compared with estimated worldwide electricity demand growth of 2.6 percent per year, so nuclear power's share of generation drops from about 15 to 10 percent. The largest drop occurs in the Organization for Economic Cooperation and Development (OECD) Europe—from 28 to 12 percent in 2030. This does not necessarily mean that OECD Europe CO_2 emissions increase; seven of the 10 largest markets for wind generation are in Europe—the 27 member European Union (EU) accounted for 65 percent of global wind capacity at the end of 2006. Most of the decline is driven by reactor phase-outs (rather than retirements) planned in Germany, Sweden, and Belgium. Increases are projected for China, Japan, India, the United States, Russia, and Korea. Most strikingly, of the net global increase of 48 GWe, 47 GWe occurs outside the OECD (including Japan and Korea) and Russia, that is, in China, India, other Asian nations, the Middle East, and Latin America.

In the Alternative Policy case, OECD Europe reactor phase-outs remain in place, but are deferred 10 years. Nuclear power share of total electricity demand in the OECD stays constant, with Pacific and North American increases offset by European declines. Developing country additions are significant—74 GWe of net additions, 90 percent of which occur in China and India. These additions result in nuclear's share of total generation rising from 2 to 6 percent in China and 2 to 9 percent in India, relative to 2005. The report adds that China has set a target to build 40 GWe of nuclear capacity by 2020, though an earlier target of 20 GWe by 2010 will not be met. In addition, while India announced in May 2006 a new target of 40 GWe nuclear by 2030, India's record of meeting targets is poor. The 10 GWe by 2000 target, set in 1984, was missed by a factor of four.

Similarly, while Russia has announced ambitious plans to complete 10 GWe of new nuclear capacity by

2015, there are many infrastructure challenges associated with this target. Russia has increased nuclear generation by 3 GWe since 1991. In addition to supply-chain challenges like those in the United States, nuclear power rates are much lower than for fossil-fired generation, leaving the industry without sufficient funds to complete new reactors on schedule.

The U.S. Energy Information Administration (EIA) also forecasts global electricity demand, and projected nuclear capacity by nation and region. Estimates for 2030 generally fall between IEA's Reference and Alternative Policy scenarios, with a total of 481 GWe projected for that year. Europe falls off less steeply; OECD Asia expands less quickly, primarily because of lower estimated growth in demand; U.S. capacity rises from 100 GWe in 2004 to 113 GWe in 2030 (see Figure 14).

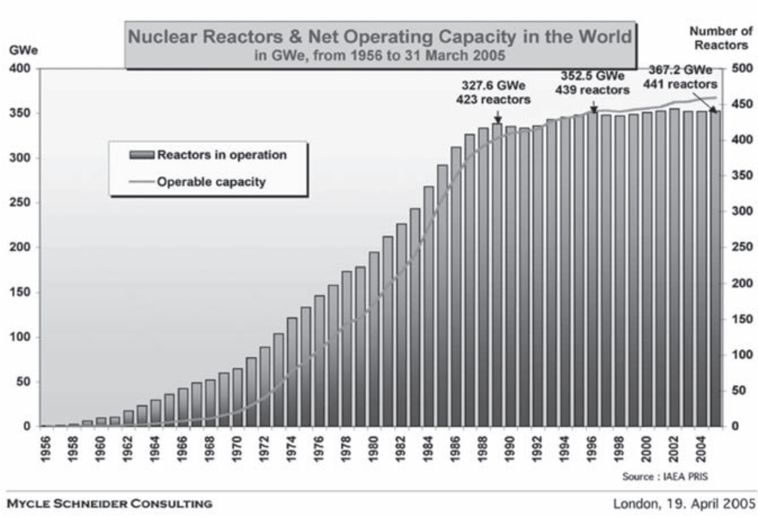

Figure 14. Three Projections of World Nuclear Energy Capacity to Year 2030.

The short story is that between 2007 and 2030, forecasts for OECD plus Russia show almost no net growth in nuclear capacity. Retirements are roughly offset by additions. In base cases, 72-100 percent of net growth occurs elsewhere, mainly in India and China. Even so, by 2030, nuclear represents only 3-6 percent (from 2 percent today) of electric generation in those two nations. By 2030, net additions are at best about 1/7th of the nuclear wedge.[24] In IEA's Alternative case, with delayed retirements in Europe, about 20 percent of the wedge is completed by 2030. The pace of scheduled retirements quickens rapidly in the ensuing years, however, requiring more than a quadrupling of annual additions to achieve a full wedge by the late 2050s.

Stated differently, it is extremely difficult to achieve a full nuclear wedge by the late 2050s, and may be impossible without expanding nuclear power to a very large number of nations that are short on internal capacity (e.g., Vietnam, Indonesia, Egypt, Saudi Arabia, Iran, Nigeria, Turkey, Mexico, Venezuela, Yemen), which includes a problematic safety culture. Many may want bulk fuel handling facilities (enrichment and perhaps reprocessing and mixed oxide fuel fabrication), which would pose enormous risks of weapons proliferation. Neither the Non Proliferation Treaty, as currently interpreted, nor the International Atomic Energy Agency (IAEA) safeguards regime, as currently implemented, are capable of meeting this challenge.

CONCLUSION

In light of these analyses, what is likely? In the near term, utilities, vendors, subsuppliers, uranium miners, and enrichment plant operators, among others, are caught in a classic chicken and egg problem. Do utilities dare order now if capacity does not exist; do vendors expand now if orders are not in existence? Between now and 2030, some increase in the U.S. nuclear industry appears probable, given life extensions of existing capacity, high fossil fuel prices, uncertain costs for carbon capture and sequestration technologies, and the incentives or subsidies in the National Environmental Policy (NEP)Act of 2005. That increase in capacity, however, is likely to be quite modest, even in the face of significant, and politically difficult, controls on carbon. Other resources—including coal with purchase of carbon credits, wind, efficiency improvements, gas, and, perhaps, other emerging renewables are broadly competitive.

Internationally, the situation is perhaps more complicated. Clearly we will have new net capacity additions in Asia, particularly in India and China. Many other nations (e.g., Vietnam) have expressed interest in new nuclear capacity. But expressions of interest do not necessarily imply sufficient domestic capacity to pursue this option, or vendor willingness to invest the time and money to pursue it.

Infrastructure in the major nuclear nations—France, the United States, Russia, Germany, and the UK—has fallen off steeply since Three Mile Island and Chernobyl. French confidence and expertise led to a relatively inexpensive turnkey contract with Finland, but it is certainly not a money-maker and could be a major loss leader. Vendors, in general, have less capacity for absorbing losses than utilities.

In essence, the most likely case is that U.S. net nuclear capacity will rise very slightly over the next 15 years. EU nuclear capacity will in all likelihood fall. Growth in China and India will be significant, but may also fall short of either EIA or IEA expectations, primarily because both use extremely optimistic cost estimates. After 2030, the problem becomes more complicated, because the pace of nuclear retirements accelerates. But it is also difficult to predict the future of other low carbon emitting technologies 20 years hence. All will benefit from carbon controls, and it is not at all clear that nuclear power will reemerge as an economically attractive resource worldwide.

One can only get to that conclusion by assuming that near-term orders will be driven by major orders in India and China that lead to infrastructure expansion worldwide; that this expansion alleviates supply-chain imbalances in key equipment, contractors, and crews; that the expansion can respond successfully to a huge ramp-up to replace existing capacity after 2020; and that the expansion is not eclipsed by improvements in energy efficiency and renewables in the interim.

ENDNOTES - CHAPTER 12

1. Jonathan Koomey and Hultman Nate, "A Reactor-Level Analysis of Busbar Costs for U.S. nuclear plants, 1970-2005," *Energy Policy*, 2007.

2. This covers the range estimated in studies by the University of Chicago and MIT, as well the U.S. Energy Information Administration estimate for advanced U.S. light water reactors.

3. John Deutch and Ernest Moniz *et al.*, T*he Future of Nuclear Power—An Interdisciplinary MIT Study*, Washington, DC: MIT, 2003.

4. American Electric Power, Nickel, Copper—London Metal Exchange; Cement, Iron, Steel & Heavy Construction, Washington, DC: U.S. Bureau of Labor Statistics.

5. Early year costs can be substantially higher in real dollars than life cycle levelized costs.

6. "Supply Chain Could Slow the Path to Construction, Officials Say," *Nucleonics Week*, February 15, 2007, Comments by Ray Ganthner of Areva.

7. *Ibid*.

8. *Ibid*.

9. "GE/Toshiba, Advanced Boiling Water Reactor Cost and Schedule at TVA's Bellefonte Site," August 2005, pp. 4.1-2, 4.1-23.

10. "A Missing Generation of Nuclear Energy Workers," *NPR Marketplace*, April 26, 2007; "Vendors Relative Risk Rising in New Nuclear Power Markets," *Nucleonics Week*, January 18, 2007, available from *marketplace.publicradio.org/shows/2007/04/26/PM200704265.html.*

11. "Lack of Complete Design Blamed for Problems at Olkiluoto 3," *Nucleonics Week*, May 17, 2007"; Areva Official Says Olkiluoto 3 Provides Lessons for Future Work," *Nucleonics Week*, May 3, 2007.

12. Jim Harding, *Caro Nucleare,* Toscany, Italy: Amici della Terra, 1984.

13. Florida and South Carolina have adopted legislation that permits recovery of annual construction costs in current rates following an annual prudence review.

14. Many public utility commissions cannot by statute include investment expenses in rates until the underlying resource is "used and useful."

15. Jim Hempstead, "New Nuclear Generation: Ratings Pressure Increasing," Moody's *New Nuclear Generation*, June 2009.

16. "DOE's Loan Guarantee Proposal Raises Questions About Viability," *Nucleonics Week*, May 17, 2007. Production tax credits of 1.8 cents/kWh, for 8 years are also available for low emissions

technologies, though these benefits do not start until commercial operation.

17. MIT, "The Future of Nuclear Power," 2003; and Joskow, "Future Prospects for Nuclear-A U.S. Perspective," Presentation at University of Paris, Dauphine, France, May 2006.

18. Dr. Thomas Neff, "Dynamic Relationships Between Uranium and SWU Prices: A New Equilibrium, Building the Nuclear Future: Challenges and Opportunities," Cambridge, MA: Center for International Studies, MIT, 2006.

19. "Which Power Generation Technologies Will Take the Lead in Response to Carbon Controls?" *Standard & Poor's Viewpoint*, May 11, 2007.

20. *Energy Technology Perspectives in Support of the G8 Plan of Action – Scenarios and Strategies to 2050*, Paris, France: International Energy Agency, 2006.

21. Stephen Pacala and Robert Socolow, "Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies," *Science*, August 13, 2004, Vol. 305., No. 5686, pp. 968-972.

22. These calculations were performed by Tom Cochran, senior scientist and nuclear program director, Natural Resources Defense Council, in connection with a Keystone Center joint fact-finding effort examining the future of nuclear power. See Keystone Center Nuclear Power Joint Fact-Finding, June 2007, available from *keystone.org/files/file/about/publications/Final…*

23. The French Melox mixed oxide fuel fabrication plant is licensed for 170 tons of fuel production per year.

24. Seven full wedges are needed over 50 years to stabilize atmospheric concentrations of CO_2 at twice pre-industrial levels.