Nonproliferation Policy Education Center

# Economics of New Nuclear Power and Proliferation Risks in a Carbon-Constrained World

By Jim Harding
June 2007

### *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 competitive and proliferation-resistant resource inside the United States or internationally.

Estimating new US reactor costs is a daunting exercise. Recent construction cost experience with advanced reactors is confined to a small number of plants completed in Asia in the 1990s. Accounting practices, labor rates, exchange rates, licensing and regulatory procedures differ from country to country. There has been significant real escalation in worldwide materials costs since 2002, and a growing nuclear industry faces key supply chain challenges. While the Japanese supply chain capacity is intact, the US, Western European, and Russian industries have been largely moribund since the Three Mile Island and Chernobyl accidents.

Other factors are also important, including finance and capital cost recovery, both of which are affected by changes in the structure and regulation of electricity markets. Prices in the thinly traded uranium spot market have risen by a factor of ten in five years.

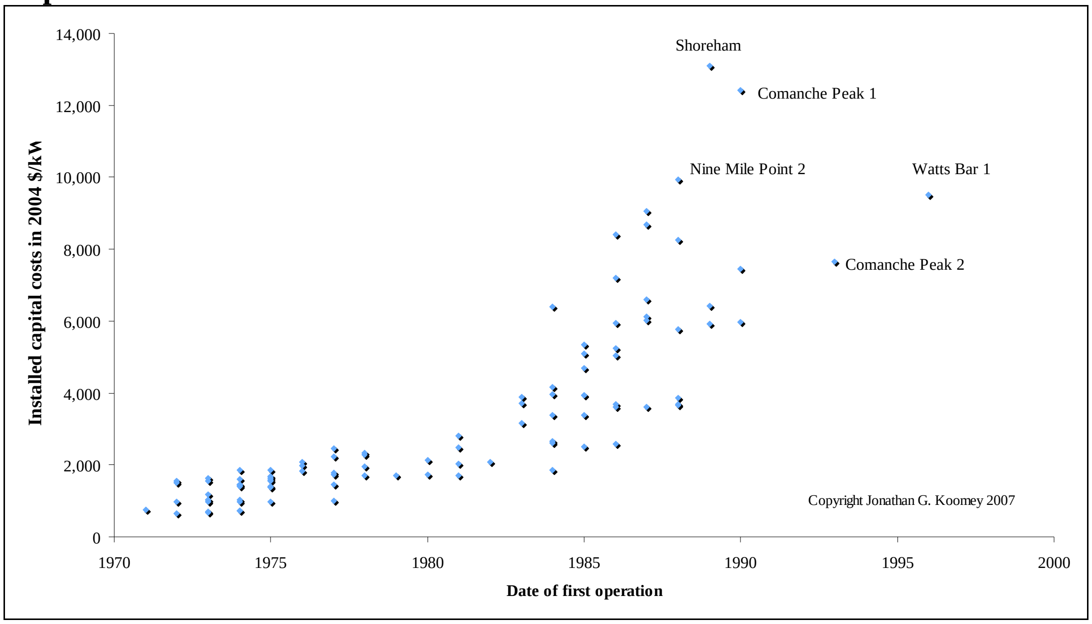
This report estimates costs of 9-12 cents per kilowatt-hour (in 2007 discounted levelized life cycle costs) for new reactors. Other traditional alternatives, including wind, coal, and gas combined cycles, have also risen in cost. Even with carbon taxes of $30/ton of CO2, or requirements for sequestration, nuclear power does not show an economic advantage that would lead to substantial near term worldwide growth – a “renaissance.”

Over the longer term, it will challenging and difficult to replace existing nuclear capacity in the US and Europe with low carbon resources, including new reactors. For new reactors to make a significant incremental contribution to the global warming problem, many new plants must be built in the developing world, and associated bulk fuel handling facilities (enrichment, reprocessing, and mixed oxide fuel fabrication) involve significant risk of weapons proliferation.

### *Capital Cost*

To estimate the cost of new reactors in the US, the best place to turn might be US 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.

**Capital costs of U.S. reactors built between 1970 and 2000**




Today, the industry predicts a better future. There are government and vendor estimates for nuclear construction in the $1,500-2,100/kW range, expressed in various year dollars.[2] The Nuclear Regulatory Commission can issue a combined license for construction and operation; utilities will want most design work completed before construction starts; and advanced designs are more standardized. Recent experience in Asia suggests that construction times can be shortened with the use of more large cranes, batch concrete plants, and maintaining an open containment during construction.

In its assessment of future nuclear costs, the 2003 MIT study, rejected these lower cost estimates as based on software, rather than real construction experience, and for failing to include key owner's costs, including land, construction oversight, and project contingencies. The report instead relied on estimates for recently complete (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 below at date of commercial operation in real 2002 dollars.[3] We have not included the

---

[1] Koomey, Jonathan, and Nate Hultman. 2007. "A Reactor-Level Analysis of Busbar Costs for U.S nuclear plants, 1970-2005." *Energy Policy* (accepted, conditional on revisions).

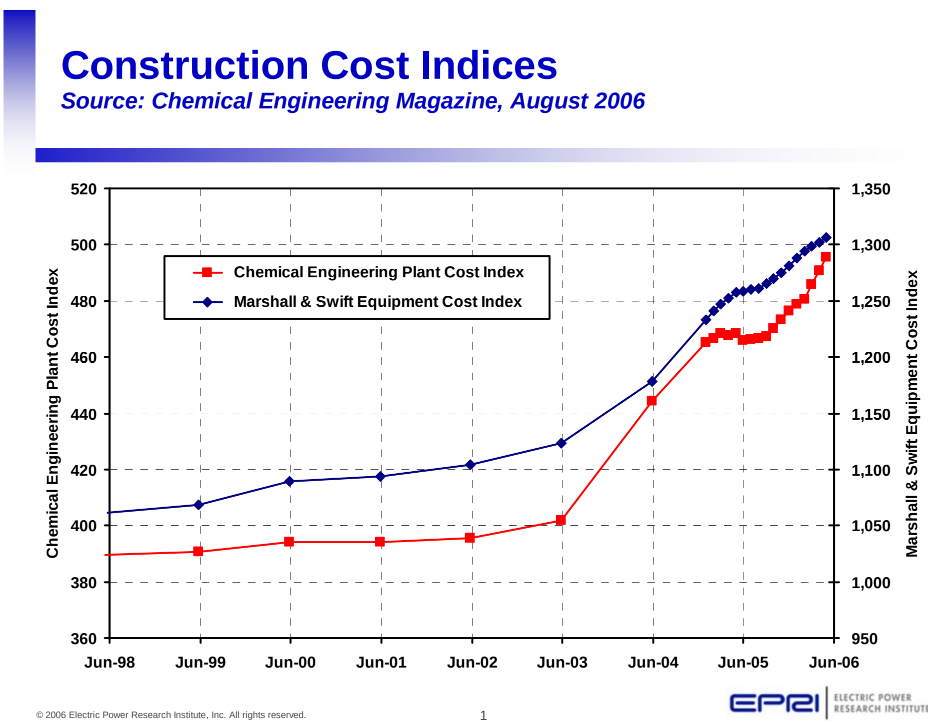
[2] This covers the range estimated in studies by the University of Chicago and MIT, as well the US Energy Information Administration estimate for advanced US light water reactors.

[3] John Deutch and Ernest Moniz, et al, The Future of Nuclear Power – An Interdisciplinary MIT Study, 2003.

South Korean units in computing the average, based on lower South Korean labor rates, though the average inclusive of these units is provided below.

| Plant | Megawatts | 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 |

The chart below, provided by the Electric Power Research Institute, shows recent cost trends for large 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. If we take the average of the recently completed Japanese reactors and escalate at from 2002-2007 at four percent real per year, overnight costs for 2007 would be approximately $3250/kW, not including either interest during construction or further real escalation.



It is very difficult to determine whether real cost escalation will continue into the future, and it clearly affects all generating options, though 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 U.S. had about 400 suppliers and 900 nuclear or N-stamp certificate holders (sub-suppliers) licensed by the American Society of Mechanical Engineers. The numbers today are 80 and 200.[4]

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% in 6 months, with a new 30% down payment requirement.[5]

Other long lead-time components, including reactor cooling pumps, diesel generators, and control and instrumentation equipment have six year manufacturing and procurement requirements. In the near term, reliance on foreign manufacturing capacity could complicate construction and licensing. 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.[6]

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.[7] Other sources have pointed to the potential for skilled labor shortages if nuclear construction expands.[8]

Several of these problems have clearly surfaced at the Olkiluoto 3 site, where the French vendor Areva is building a 1600 megawatt advanced European pressurized reactor (EPR). Areva originally estimated a four 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 be between $700-900 million. 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 NP President Luc Oursel indicated that the company had underestimated what it would take to reactivate the global supply chain for

---

[4]"Supply Chain Could Slow the Path to Construction, Officials Say," *Nucleonics Week*, February 15, 2007. Comments of Ray Ganthner, Areva.
[5]*Ibid*.
[6]*Ibid*.
[7]"GE/ Toshiba, Advanced Boiling Water Reactor Cost and Schedule at TVA's Bellefonte Site," Aug. 2005, pp. 4.1-2 and 4.1-23.
[8]"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. http://marketplace.publicradio.org/shows/2007/04/26/PM200704265.html.

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."[9]

The industry believes that standardization and "learning curves," coupled with clearing 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 US 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, sub-suppliers, and construction crews operating near capacity and able to move smoothly from one project to the next.[10] 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 require 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 non-utility owned generation. The utility might then be required to run a competitive procurement process that might 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 pro-active position, for example by permitting utilities to recover construction work in rate base despite near-term rate impacts.[11] In other states, charging costs to customers before the plant came into service would not be acceptable or consistent with current law.[12]

---

[9] 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.
[10] Jim Harding, *Caro Nucleare*, published by Amici della Terra, 1984.
[11] Florida and South Carolina have adopted legislation that permits recovery of annual construction costs in current rates following an annual prudence review.
[12] Many public utility commissions cannot by statute include investment expenses in rates until the underlying resource is "used and useful."

The MIT study assumed a financial structure of 50% debt (at 8 percent) and 50% 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.

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, DOE released a second draft of its loan guarantee rules. The draft rule provides for the federal government to guarantee 90% of the debt, so long as the amount does not exceed 80% 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 non-guaranteed fraction of debt is subordinated to the covered piece; 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."[13] Four billion dollars in loan guarantees also might cover 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 US Energy Information Administration assumes a six year construction period for a new reactor. Some vendors believe it can be done in four years. The MIT base case was five years.

Further real escalation for nuclear reactors, or other supply options, should not be ruled out. In fact, some real escalation should be assumed, based on tight supply-demand imbalances in metals, component costs and lead times, and skilled construction crew availability. If we assume a continuation of this trend, real discounted overnight costs, not including interest during construction are roughly $4200/kW in 2007 dollars. If the rate falls to 2.5 percent real, this value drops to $3850/kW. Interest during construction adds between $500-900 million in real 2007 dollars. Final construction costs in real 2007 dollars range from $4300-4550/kW. This is not far from a May 2007 estimate of

[13] "DOE's Loan Guarantee Proposal Raises Questions About Viability," *Nucleonics Week*, May 17, 2007. Production tax credits of 1.8 cents/kWh, for eight years, are also available for low emissions technologies, though these benefits do not start until commercial operation.

$4000/kW from Standard & Poor's, but it is also probably too narrow, given construction time and real escalation uncertainties.[14]

### *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% during most of the 1980s to nearly 90% in the post-2000 period.[15] Some of the increase is attributable to changes in technical specifications that 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"). Seventy five to eighty five percent is a reasonable lifetime range for future units.

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 US average is about $100-$120/kW-year, inclusive of A&G (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 kilowatt hour cost for all these steps, based on then-current uranium prices of $13.60/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.

Uranium prices have been volatile over the past three 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 two decades has been met by inexpensive "secondary supplies," including surplus inventories from cancelled or shut-down units (1980s-1990s) in the US, Western Europe, and Russia, purchase of surplus Russian and US government stockpiles (mid-1990s), and diluting highly enriched uranium from surplus Russian nuclear weapons (1998-2013) with natural uranium.

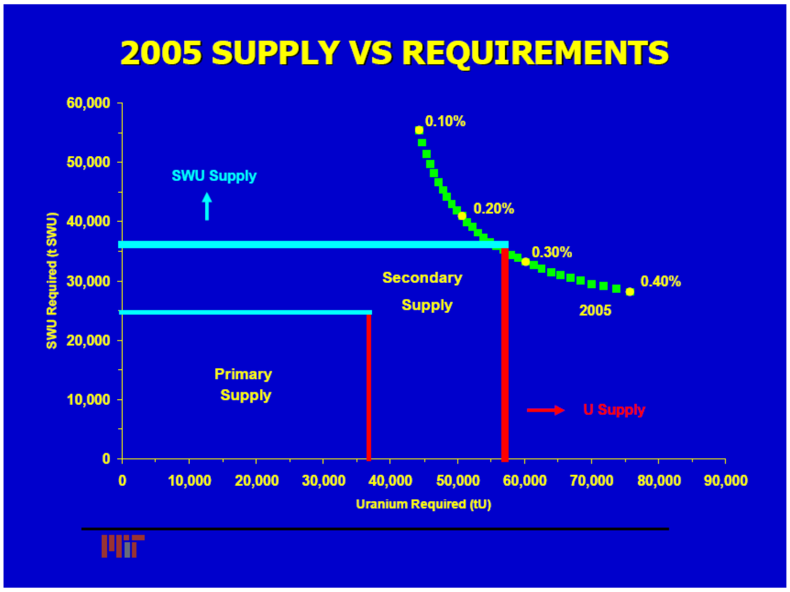
---

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

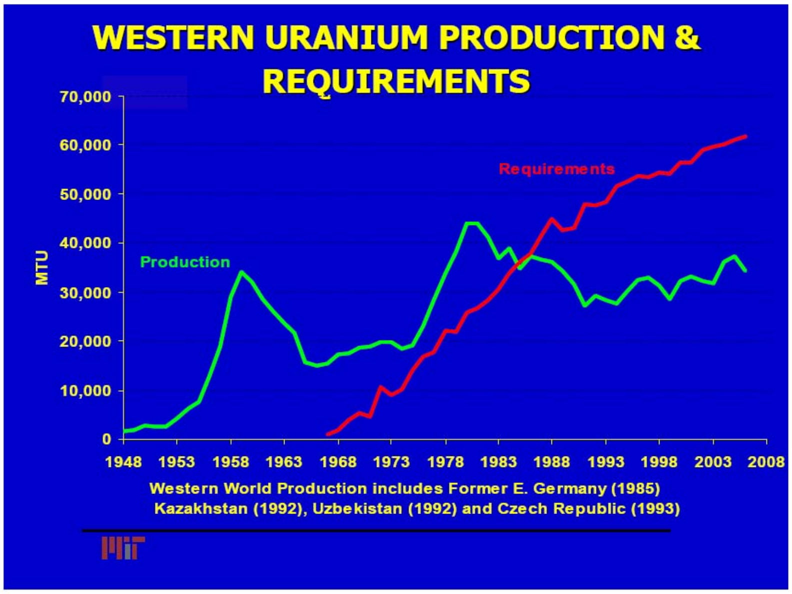
[15] MIT, "The Future of Nuclear Power," 2003; and Joskow, "Future Prospects for Nuclear-A US Perspective," Presentation at University of Paris, Dauphine, May 2006.

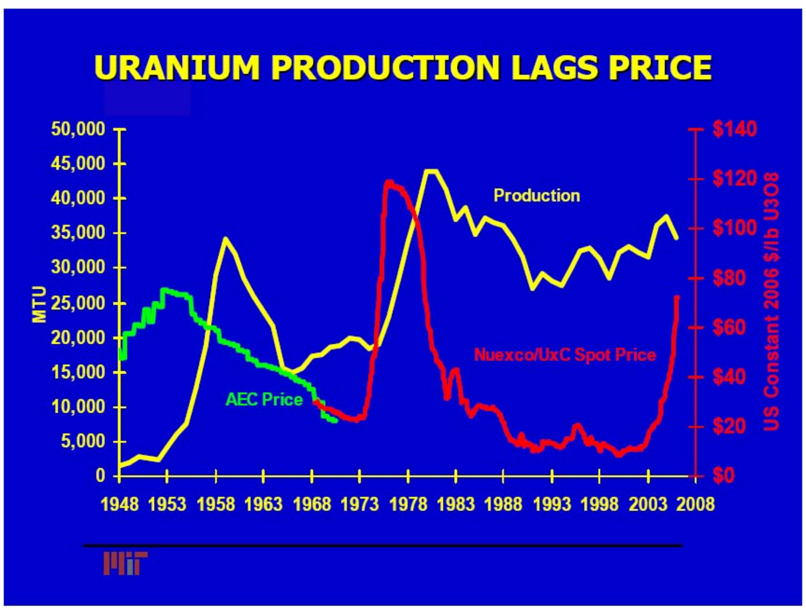
Worldwide uranium production is about 60 % of current uranium demand.[16] Existing spot uranium prices clearly support enhanced production, both in the US and abroad, but lead times for new mines are long. The same situation applies to enrichment. Uranium mining expansion will need to be better than 1980s rates of expansion to meet 2015 demands, particularly with limited enrichment capacity worldwide.

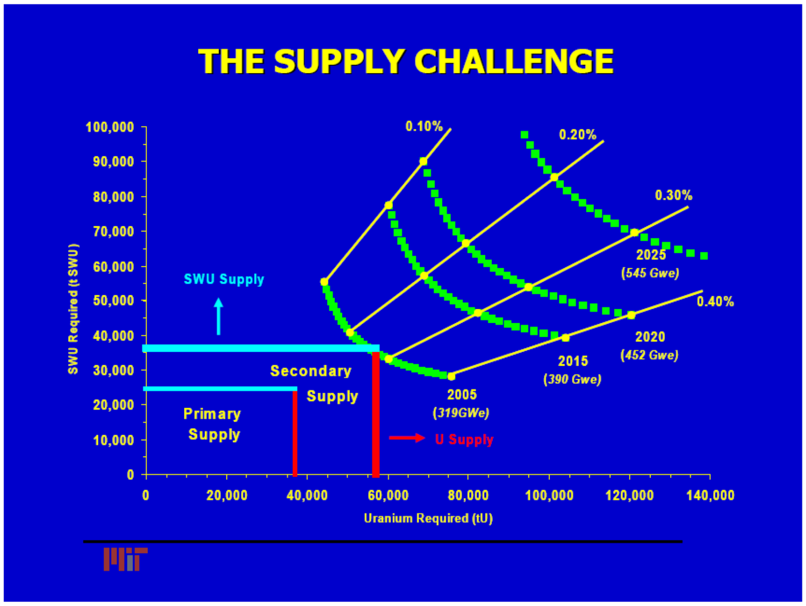
The following four charts from Tom Neff at MIT illustrate the history and the challenge.[17] The first chart shows demand for uranium and enrichment services (SWUs or separative work units) in 2005. Regardless of how enrichment facilities are operated (the green curve, and associated "tails assay"), current demand could not be met without secondary supplies. The second and third charts show growth in uranium demand and the lag between price and increased production. The final chart shows how much mining and enrichment capacity must be added to make up for lost secondary supply and meet the needs of a growing industry.



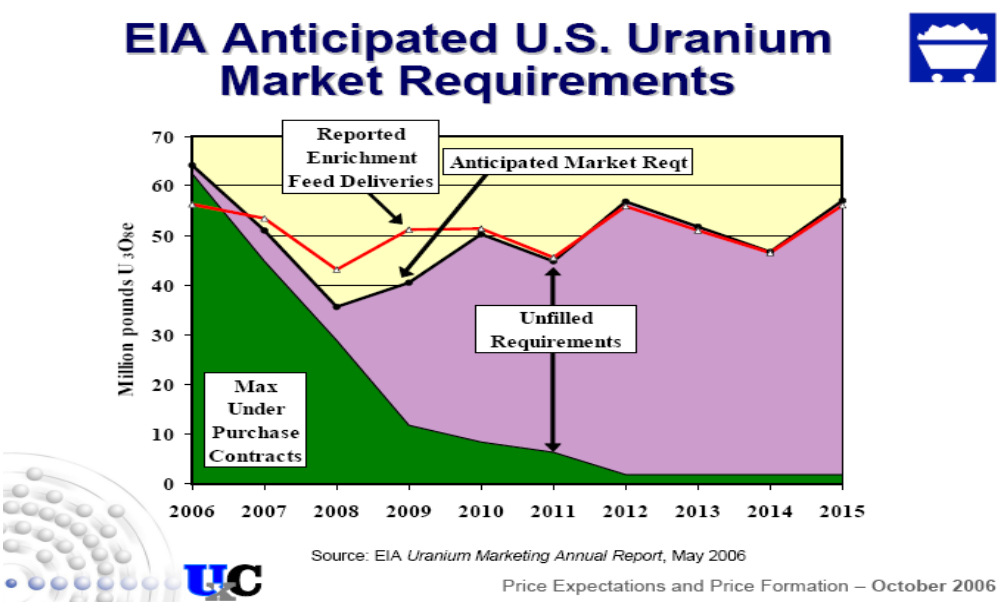

[16] Dr Thomas Neff, Center for International Studies, MIT, "Dynamic Relationships Between Uranium and SWU Prices: A New Equilibrium, Building the Nuclear Future: Challenges and Opportunities."
[17] Dr Thomas Neff, Center for International Studies, MIT, "Uranium and Enrichment – Supply, Demand, and Price Outlook," presentation to the Winter Energy Conference, Banff, January 2007.


WESTERN URANIUM PRODUCTION & REQUIREMENTS
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
MTU
Requirements
Production
1948 1953 1958 1963 1968 1973 1978 1983 1988 1993 1998 2003 2008
Western World Production includes Former E. Germany (1985)
Kazakhstan (1992), Uzbekistan (1992) and Czech Republic (1993)

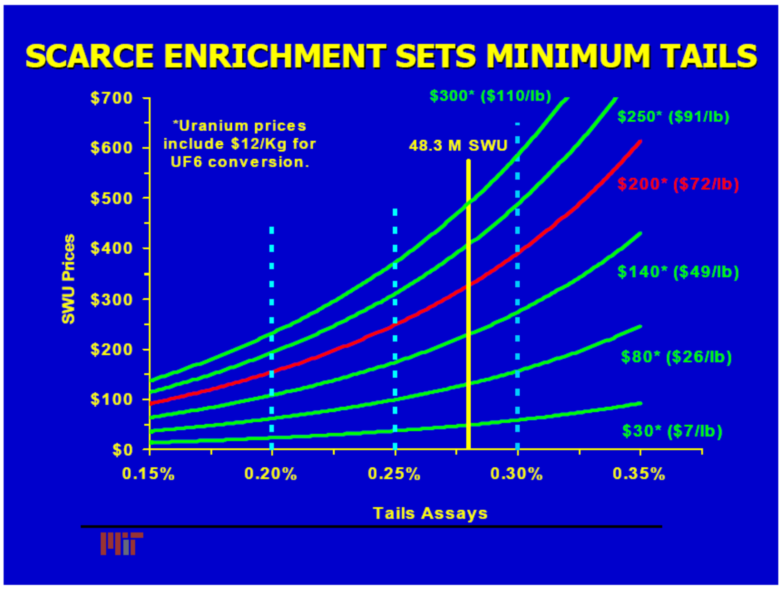

URANIUM PRODUCTION LAGS PRICE
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MTU
Production
Nuexco/UxC Spot Price
AEC Price
$140
$120
$100
$80
$60
$40
$20
$0
US Constant 2006 $/lb U3O8
1948 1953 1958 1963 1968 1973 1978 1983 1988 1993 1998 2003 2008




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 2012-2013 must enter the market this year or next to ensure adequate supplies going forward.



Neff and Jeff Combs from UX Consulting suggested that uranium prices may continue to increase beyond its historical peaks. It already has. This problem is complicated by the fact that uranium and enrichment are partial substitutes for each other. When utilities actually pay a high price for uranium, they will want a much lower "tails assay" at the enrichment facility, saving uranium, but also cutting the capacity of existing enrichment plants by 30 percent, whereupon demand cannot be met. With limited enrichment capacity, utilities are forced to settle for a higher than optimal tails assay. Prices equilibrate when the cost of substituting one product for the other is equal.




Assuming current prices for uranium and enrichment ($135/lb and $140/kgSWU), nuclear fuel cycle costs are about three times the value calculated in the MIT analysis (1.6 cents/kWh). If we assume the same value for uranium, but derive SWU price from Neff's analysis, nuclear fuel cycle costs reach 2.6 cents/kWh. A midpoint of $340/kgSWU yields about 2 cents/kWh. No real cost increases are considered for other fuel cycle steps, including conversion, fabrication, and waste management and disposition.

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.

***Summary of Nuclear Costs without Carbon Controls***

| **Main Assumptions (2007$)** | **Low Case** | **High Case** |
|---|---|---|
| Overnight Cost | $3,250/kW | $3,250/kW |
| Plant Life | 40 years | 30 years |
| Capital Cost, Including Real Interest | $4,300/kW | $4,550/kW |
| Capacity Factor | 90% | 75 % |
| Financial | 8% debt, 12% equity, 50/50 ratio | 8% debt, 15% equity, 50/50 ratio |
| Depreciation | 15-year accelerated | 15-year accelerated |
| Fixed O&M | $100/kW/year | $120/kW/year |
| Variable O&M | 0.5 cents/kWh | 1 cent/kWh |
| Fuel | 1.6 cents/kWh | 2.0 cent/kWh |
| Grid Integration | $20/kW/year | $20/kW/year |

**Lifecycle Costs**
(Cents/kWh)

| **Cost Category** | **Low Case** | **High Case** |
|---|---:|---:|
| Capital Costs | 6.0 | 7.9 |
| Fuel | 1.6 | 2.0 |
| Fixed O&M | 1.3 | 1.8 |
| Variable O&M | 0.5 | 0.5 |
| Total (Levelized Cents/kWh) | 9.4 | 12.2 |

***Carbon Constraints***

With carbon constraints (specified as taxes or a cap-and-trade approach), nuclear power's competitive position improves. Standard & Poor's recently released an economic analysis on the sensitivity of generation technologies to carbon controls.[18] Only plant – rather than full fuel cycle – emissions were considered, albeit insignificant. The base case capital cost estimate for nuclear power was $4000/kW, which is generally in line with the values calculated here. O&M costs were in line with the values calculated here, but 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 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. The first row of bold

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

numbers shows internal costs, without carbon capture or taxes. The second bold row shows costs with capture and sequestration, and the final bold row shows costs with carbon credits or taxes of $10-30/ton. As shown, nuclear power only has a modest advantage over coal (either pulverized or 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 CO2.

| | **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***[19] |
| 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*** |

The S&P estimates for carbon capture appear pessimistic, and for pulverized coal, unrealistic. A recent International Energy Agency 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 CO2 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.

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

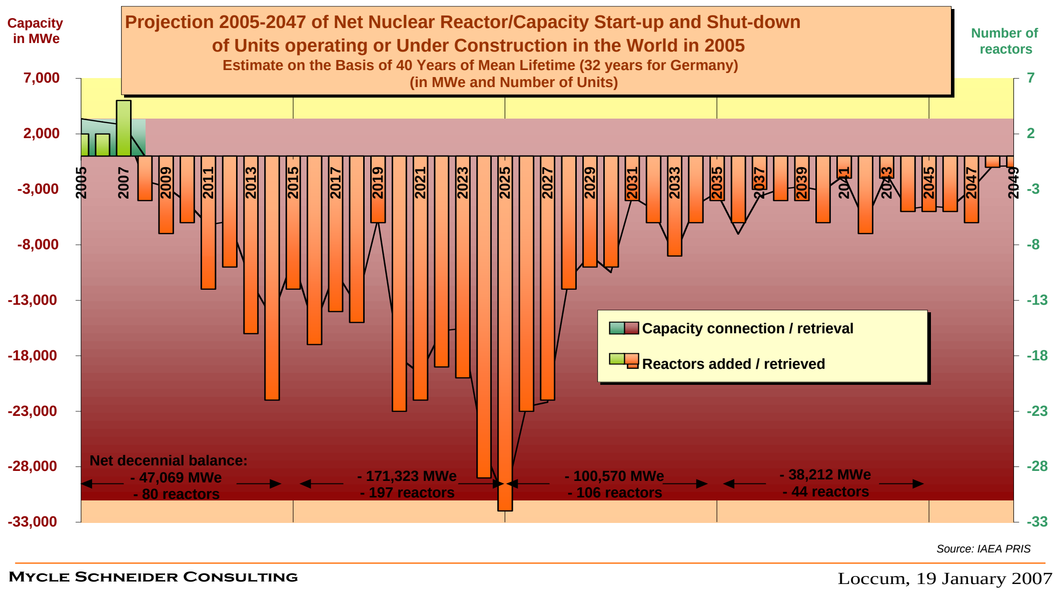
For example, at 0.1-0.5 metric tonnes of oil per tonne of CO2 injected, the credit would range from $30-160 per tonne of CO2, substantially diminishing, and perhaps offsetting entirely, costs for capture, transport, and storage.[20] Finally, if carbon is taxed or credits are available for $10-30/ton in national or international markets, coal and gas plant developers may pursue projects without 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 CO2), 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 fifty years with current technologies.[21] Pacala and Socolow proposed fifteen 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 CO2 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 GWe to 700 GWe over fifty years.

The authors assumed that this capacity would displace efficient coal generation. Over the same period of time, essentially all existing reactors are retired, so 1070 GWe must be built to achieve a wedge.

[20] International Energy Agency, Energy Technology Perspectives in Support of the G8 Plan of Action – Scenarios and Strategies to 2050, 2006. This credit can be geographically and temporally limited.
[21] Pacala and Socolow, "Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies," *Science*, 13 August 2004, Vol. 305. no. 5686, pp. 968 – 972.]




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
- 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 tonnes of heavy metal per year, but 40 tonnes/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]

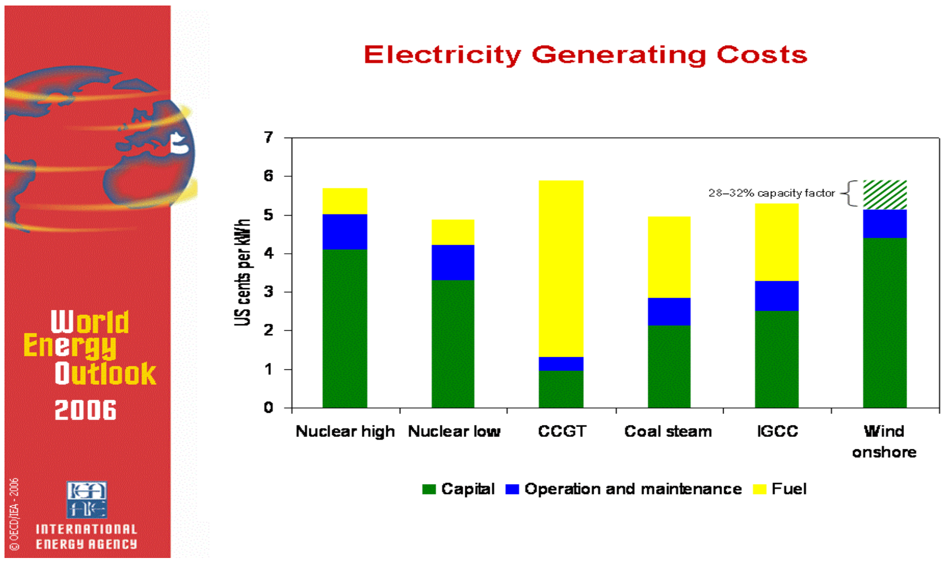
Pacala and Socolow did not directly examine the question of whether 1070 GWe of nuclear capacity and associated fuel cycle facilities could be built over fifty years. National and international forecasts of future nuclear capacity typically do not go beyond existing utility planning horizons of 10-20 years.

---

[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. The report will be released in early June 2007.

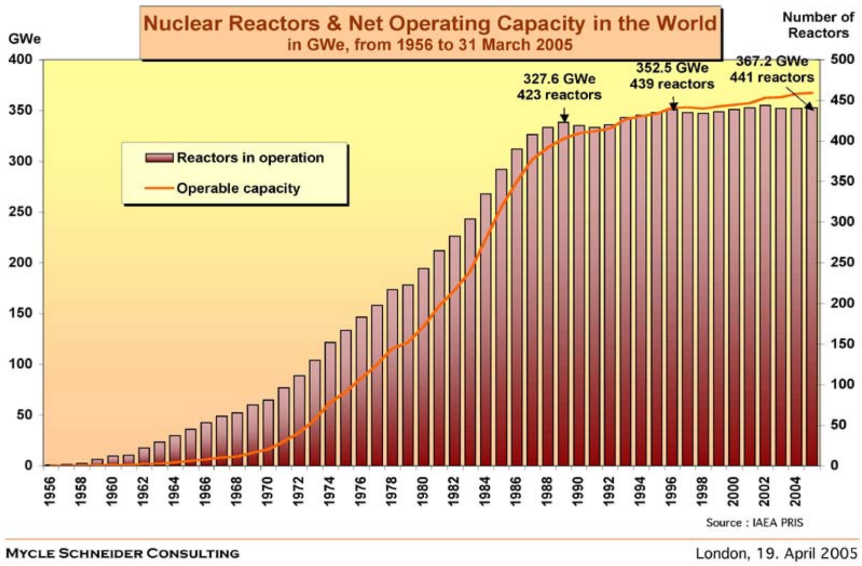
[23] The French Melox mixed oxide fuel fabrication plant is licensed for 170 tonnes of fuel production per year.

A recent analysis by the International Energy Agency (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) and lifecycle costs (4.9-5.7 cents/kWh). It assumes that existing government policies remain largely unchanged.




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 the chart below 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.




.

IEA's World Energy Outlook 2006 acknowledges several important challenges facing 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 Reference case, 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%. The largest drop occurs in OECD Europe – from 28 to 12 percent in 2030. This does not necessarily mean that OECD Europe CO2 emissions increase; seven of the ten largest markets for wind generation are in Europe – the 27 member European Union accounted for 65 percent of global wind capacity at the end of 2006. Most of the decline is driven by phase-outs (rather than retirements) planned in Germany, Sweden, and Belgium. Increases are calculated for China, Japan, India, the US, 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, in China, India, other Asian nations, the Middle East and Latin America.

In the Alternative Policy case, OECD Europe phase-outs remain in place, but are deferred ten 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, ninety percent of which occur in China and India. These additions result in nuclear's share of total generation rising from 2% to 6% in China and 2% to 9% percent in India, relative to 2005. The report adds that China has set a target to build 40 GW 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 US, nuclear power tariffs are much lower than for fossil-fired generation, leaving the industry without sufficient funds to complete new reactors on schedule.

The US Energy Information Administration 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; US capacity rises from 100 GWe in 2004 to 113 GWe in 2030.

| ***Source*** | ***GW 2030*** | ***GW/yr*** | ***% world electricity*** | ***Net additions*** | ***% Net Additions Outside OECD and Russia*** |
|---|---|---|---|---|---|
| ***IEA Reference (WEO)*** | ***415*** | ***2 GW*** | ***10%*** | ***45*** | ***~100*** |
| ***IEA Advanced*** | ***519*** | ***6.5 GW*** | ***15%*** | ***149*** | ***50*** |
| ***US EIA*** | ***481*** | ***4.7 GW*** | ***12%*** | ***110*** | ***72*** |

The short story is that between 2007-2030, forecasts for OECD + 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 India and China. Even so, by 2030, nuclear represents from 3-6 percent (from 2 percent today) of electric generation in those two nations. By 2030, net additions are at best about 1/7$^{th}$ of one wedge.[24] In IEA's advanced case, with delayed retirements in Europe, about 20% of a 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.

[24] Seven full wedges are needed over 50 years to stabilize atmospheric concentrations of CO2 at twice pre-industrial levels.

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), including safety culture. Many may want bulk fuel handling facilities (enrichment and perhaps reprocessing and mixed oxide fuel fabrication) that pose enormous risks of weapons proliferation. Neither the Non Proliferation Treaty, as currently interpreted, nor the 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, sub-suppliers, uranium miners, and enrichment plant operators, among others, are caught in a classic chicken and egg problem. Do utilities dare order if capacity does not exist; do vendors expand if orders are not forthcoming? Between now and 2030, some increase in the US 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 NEPAct 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.

Looking internationally 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 US, Russia, Germany, and the UK – has fallen off steeply since TMI 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 US 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 twenty years hence. All will benefit from carbon controls, and it is not at all clear that nuclear power will re-emerge 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; can respond successfully to a huge ramp-up to replace existing capacity after 2020; and is not eclipsed by improvements in energy efficiency and renewables in the interim.