CONQUERING DEREGULATION: HOW THE U.S. NUCLEAR INDUSTRY IS DOING IT

Robert D. MacDougall
Neil J. Numark
Numark Associates, Inc.

Published in the newsletter of the Japan Atomic Industrial Forum,
November 2000 (in Japanese)

Twenty-five U.S states have now adopted measures to reduce or eliminate the regulation of retail electricity prices. The move to open market competition among power generators has been painful for consumers and utilities alike this summer in some parts of the country, and the pain is probably not over yet. Like the airline, railroad, trucking, natural gas, and telecommunications industries before it, the electric power industry is likely to experience shocks in the transition to open markets. Eventually, the deregulation of these other industries did bring lower prices, expanded markets, and a smaller number of bigger, more competitive, more efficient producers and suppliers. Electricity deregulation in the U.S. is still in the first inning of play, and some worry of a darker future if deregulation does not offer sufficient incentives for new powerplant construction. But the benefits of competition in other formerly-regulated industries are too apparent for state policymakers to forfeit the game in the power industry now. It is instructive that even in California, where electricity prices have been highest and most volatile, the state utility commission in August rejected a petition to freeze rates. It appears that the deregulation of U.S. electricity markets is here to stay.

Seventy-six of the nation's 103 operating nuclear powerplants are in states moving toward open retail electricity markets. Many of them have substantial "stranded costs" -- mainly unpaid debt -- likely to be unrecoverable from power generation revenues at expected prices in competitive markets. But contrary to the fears of the industry and hopes of its critics, deregulation has not stifled nuclear power in the United States; it even appears to be stimulating the industry's competitiveness. One reason for this surprising turnaround is that many state regulators have permitted utilities to recover more stranded costs than originally expected, through higher regulated rates during longer transitions to open markets. But the regulatory good news is only part of the story. By almost any measure, nuclear plants in the U.S. are more productive, more efficient, cheaper to operate and maintain, and safer than they were even five years ago, at the threshold of the retail competition era.

Nuclear plants have also become more valuable, and more likely to keep operating. In many cases traditional utilities having integrated generation, transmission and distribution functions are breaking apart; the component parts are consolidating through mergers and buyouts into new and larger unregulated “genco’s” and still-regulated transmission/distribution utilities. As part of this restructuring, several nuclear units have already changed hands and more are currently on the auction block. Acquisition prices have increased almost tenfold in the past year and a half, and about 60% of all U.S. plants are now affected by current or planned acquisitions, mergers, joint operating companies, or some other form of consolidation. As the economics of existing nuclear plants have improved, and the U.S. Nuclear Regulatory Commission (NRC) has granted timely life extensions, many more plant owners are preparing to seek renewal of their operating licenses for up to 20 years beyond their original 40-year terms. The U.S. Department of Energy recently told Congress that "the overwhelming majority" of the country's 103 currently operating reactors will continue operation under extended licenses "well past 2030."

Meantime, utilities are taking advantage of NRC's more flexible "risk-informed, performance-based" regulatory posture to apply for relief from overly conservative requirements that can be shown through accepted probabilistic risk assessment (PRA) techniques to have minimal safety benefit. Based on these techniques, NRC has stepped up its approvals of licensees' applications to uprate their plants' maximum thermal capacity. Altogether, NRC-approved power uprates added 2,200 MW of capacity between 1988 and 1999, according to a recent Nuclear Energy Institute survey, and licensees currently plan to seek approval for another 842 MW of capacity upratings. NRC has also allowed many plants more time on-line to generate revenues. The agency now routinely approves higher-burnup fuel reloads that have extended refueling cycles from 12 months to 18 and 24 months.

Although U.S. electric power deregulation is still at an early stage and significant uncertainties remain, there is good and growing evidence that currently operating nuclear plants may not only survive open competition, but even thrive in it. A few years ago, this turn of events was almost inconceivable to all but the staunchest industry optimists. How did it happen? What have the owners, operators, and suppliers of U.S. commercial reactors done to help make it happen, and what are they planning to do to stay competitive? Even if they succeed, will they want to build new reactors here some day? If so, what kinds of reactors, and when? This article examines these questions, and offers provisional answers based on the evidence available so far.

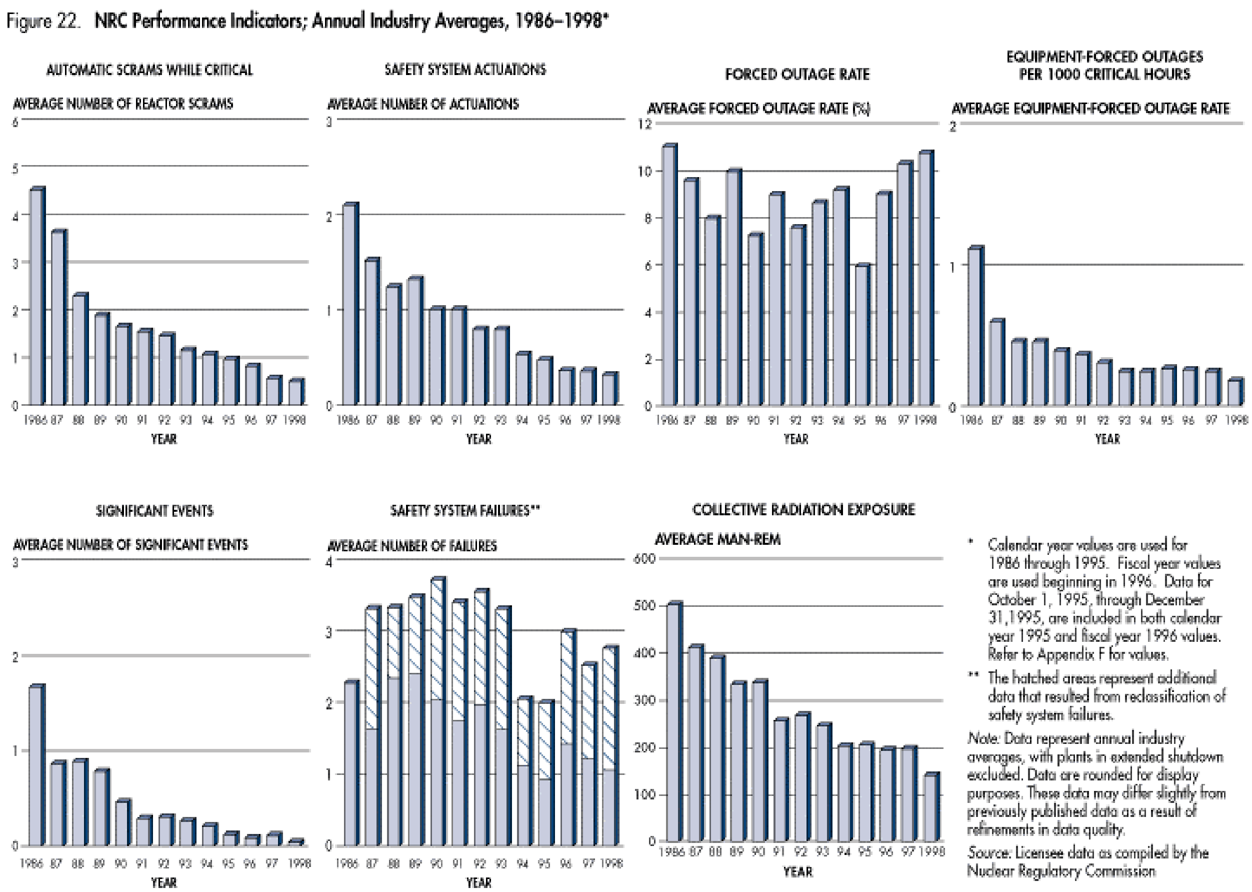
More Production, More Safety:

Capping more than a decade of steady improvements, the overall performance of U.S. nuclear powerplants reached record levels in 1999. Last year, U.S. plants generated 728 billion kWh, 54 billion more than 1998, and an all-time record in nuclear generation. "That year-to-year boost equaled the output of six more 1,000 MW plants," noted Donald Hintz, the CEO of Entergy Corporation, at a recent industry conference. "At a conservative market-clearing price of 3 cents/kWh, that amounts to an additional $1.5 billion of cash flow in the nuclear industry—and a $1.5 billion boost to the nation’s economy with only minimal capital investment."

According to the World Association of Nuclear Operators (WANO), which keeps a variety of operating statistics on reactors worldwide, the trend toward higher economic performance has also gone hand-in-hand with improvements in safety and even waste management. Unplanned shutdowns due to the automatic operation of reactor safety systems, for example, remained at a mean value of zero per reactor year for the second year in a row, down from a median 1.2 scrams per reactor year in 1990.

WANO’s figures are consistent with NRC's records of significant safety events at U.S. reactors. As of October 1999, the industry-wide average of significant events among operating U.S. plants had declined to .03 per unit, down more than an order of magnitude from the 1990 average, and two orders of magnitude from the high of 2.38 significant events per unit in 1985. Collective radiation doses to workers at U.S. nuclear plants have declined to levels at or near the lowest WANO has so far recorded. As NRC itself recently said, "All the evidence suggests that the safety and reliability of the nuclear industry has improved markedly since the late 1980's and early 1990s." NRC data independently confirming these trends appear in the graphs below.

Figure 1: NRC Performance Indicators; Annual Industry Averages, 1986-1998



One concern the NRC staff has raised about deregulation is that it could "decrease the reliability of the grid and increase the time to restore electric power following a loss of offsite power (LOOP)," NRC staff wrote to the Commission last year. Deregulation therefore "could be an important concern in the evaluation of potential [Station Black-Out] accidents" and there could be "a potential decrease in the reliability of the offsite power system during the transition period."

Although NRC feels there is likely to be low added risk resulting from grid-related LOOP events due to deregulation, they expect licensees to properly maintain and monitor plant features for coping with LOOP and SBO. "In addition to the appropriate command, control and communication infrastructure with the grid controlling entity," the staff said, "existing regulatory controls should ensure the reliability of emergency power generators and the adequacy of protective relays and alarms for the switchyard and emergency buses.”

More Consolidations:

Nuclear plants have also become more valuable. Stable or declining operating and maintenance (O&M) costs make possible, for example, long-term supply contracts with larger industrial customers interested in hedging against the volatility of prices for gas-generated power. In California’s competitive market, for example, some large users recently contracted with nuclear generators at a premium above the market clearing price in order to lock in an assured supply at a firm price, as protection against volatility in the wholesale power market.

Furthermore, the nuclear industry's large baseload units have yet to be recognized for the value they provide in voltage support and maintaining the reliability and stability of the transmission grid. Under deregulation, traditionally integrated utilities in most states are required to "unbundle" their generation functions from power transmission and distribution services, either by selling their generating operations or separating them into subsidiaries to sell exclusively into markets outside their home states. In this coming market, Entergy’s Hintz predicts that "we will all see the stabilizing value of 25% of the nation’s power generation. And I think some are going to be very willing to pay for that extra value."

As the plants’ competitive value has become more apparent, so has the value of consolidating their ownership and operation into larger corporate units. Consolidation gives owners and operators more buying power for fuel, parts, and new equipment, and more economies of scale in staffing and spreading fixed costs. As the table below indicates, when current merger plans are completed, the five largest of the 27 emerging reactor operating entities -- Exelon, FPL/Entergy, Duke, Nuclear Management Co. and Southern Nuclear Operating Co. -- will account for almost half of all U.S. nuclear plants. If the 8-plant STARS (Strategic Teaming and Resource Sharing) alliance of six Midwestern and Southwestern utilities becomes a licensed operating company for these units, just ten U.S. operating companies will control three-quarters of the nation’s U.S. reactors. In any case, a majority of the biggest U.S. operators of nuclear plants will no longer be traditional integrated utilities. Their plants will use other companies' transmission and distribution grids to deliver power to far-flung markets with customers that may be several states away.

Figure 2

THE NEW U.S. NUCLEAR POWERS

Companies/Alliances That Will be Running the Nation's Nuclear Fleet After All Consolidations Announced To Date Take Effect

ENTITY	NUMBER OF NUCLEAR UNITS
Exelon Generation Company[1]	20[2]
Florida Power & Light/Entergy	12
STARS Alliance[3]	8
Duke Power	7
Nuclear Management Company[4]	7
Southern Nuclear Operating Company	6
Tennessee Valley Authority	6[5]
Carolina Power & Light/Florida Power Corp.	5

1 Planned merger of Unicom and PECO Nuclear

2 Includes two shutdown units at Zion; also includes four units owned or soon expected to be owned by AmerGen, a joint venture of PECO Nuclear and British Energy.

3 Strategic Teaming and Resource Sharing Alliance. STARS is not an operating company, but an alliance among several operators for improved staffing efficiencies and procurement economies. Member companies' executive managements may decide to form an operating company in the future, however. Member companies are Ameren/UE Corp.; TXU Electric; Pacific Gas & Electric; South Texas Project Operating Co.; and Wolf Creek Nuclear Operating Co.)

4 Non-owning operator. Now holds licenses of nuclear units of participating utilities.

5 Includes shutdown unit at Browns Ferry. Does not include 3 partially-completed units at Bellefonte and Watts Bar.

Dominion Generation	4
FirstEnergy Nuclear Operating Co.	4
Arizona Public Service Co.	3
Public Service Electric & Gas	3
American Electric Power	2
Baltimore Gas & Electric	2
PPL Corporation	2
Southern California Edison/San Diego Gas & Electric	2
Niagara Mohawk	2[6]
Northeast Utilities	2[6]
Consumers Energy	1
Detroit Edison	1
Energy Northwest	1
Nebraska Public Power District	1
North Atlantic Energy Service Corp.	1
Omaha Public Power District	1
Rochester Gas & Electric	1
South Carolina Gas & Electric	1
Consolidated Edison	1[6]

More License Renewals:

As O&M costs, already comparable to coal-fired baseload capacity, have stabilized at a much lower level over the past several years, more nuclear operators have concluded that it is far cheaper to keep their amortized older nuclear units running than to build new generating capacity. Thus, many plant owners are preparing to seek NRC renewal of their licenses for extended operation up to 20 years beyond the 40-year term of their original licenses. As one utility engineering manager told us, “It’s almost a foregone conclusion that we’re going to

[6] Units currently up for sale

relicense all our plants. We think it'll be from $10 to $15 million a plant to do it. This is way cheaper than building any new capacity."

NRC has already approved life extensions for 5 units, at Calvert Cliffs and Oconee, and released firm dates for renewal applications for 29 more over the next three years. It has also reported receiving confidential tentative dates for 16 more units, and utility expressions of interest in preparing applications for yet another 43 units. This makes a total of 95 of the 103 U.S. units now under consideration for license renewal – a proportion that would have been considered almost delusional only three years ago.

It is too early to make confident predictions about the ultimate number of U.S. reactors that will be allowed to extend their operating lives. NRC has not received an application for any boiling water plant, for example, and it is conceivable that a generic age-related safety issue could still arise that would impede renewal efforts. But by and large, the regulatory uncertainties after successful NRC reviews at Calvert Cliffs and Oconee do not appear to be unmanageable to these operators. The economics of continued reactor operation are too compelling for them to abandon lightly their current pursuit of reactor life extensions.

More "Risk-Informed" Regulation:

Nuclear operators are also taking advantage of NRC's more flexible "risk-informed, performance-based" regulatory posture to apply for relief from overly conservative requirements that can be shown through accepted PRA techniques to have minimal safety benefit. The Commission's commitment to the implementation of risk-informed regulation has been an important development in U.S. reactor regulation that has enhanced the competitiveness of existing plants.

Until the past few years, NRC established safety requirements based largely on a deterministic approach, under which a safety problem is assumed to occur if it can be shown that the problem can occur. This deterministic approach to regulatory decision-making took little account of the consequences of any particular equipment failure or human error, and even less of the probability of these events. Thus, significant resources have been spent on safety risks that may not be significant.

In contrast, risk-informed regulation considers insights about the probability and consequence of a potential safety problem, together with other factors, in establishing agency requirements. According to a recent NRC White Paper on risk-informed regulation, its purpose is to focus licensee and regulatory attention on design and operational issues "commensurate with their importance to health and safety." It is also to provide, among other things, a logical way of setting regulatory priorities "based on risk significance, operating experience, and/or engineering judgment." Thus, as the Commission itself acknowledged in a 1999 White Paper on the subject, risk-informed regulation can be used "where appropriate … to reduce unnecessary conservatism in deterministic approaches."

Plant maintenance is a major area where the industry sees opportunities to reduce operating costs by reducing this "unnecessary conservatism." Utilities are cooperating to improve the quality and widen the application of PRA to other areas of plant operation, and have already received relief from costly NRC requirements for in-service inspection and testing that have marginal payoffs in risk reduction.

More Capacity Upratings:

One recently issued NRC regulation is a good example of the agency's new alertness to opportunities to improve nuclear plants' competitiveness with minimal safety impacts. The rule allows reactor licensees to reduce the assumed power level used in evaluating emergency core cooling system (ECCS) performance. By permitting licensees to assume that less power needs to be held in reserve for the operation of the ECCS, this rule effectively permits plant operators to sell more power than the maximum rating approved in the original license. The new rule can now be used by all 103 operating U.S. plants for a 1% power uprate at minimal cost. NEI estimates that this represents an additional 970 MW of capacity fleetwide.

As the NRC put it in its announcement, the final rule "allows interested licensees to pursue small, but cost-beneficial power uprates and reduce regulatory burden without compromising the safety margin of a facility." Arguably, the agency's willingness to devote its resources to reducing regulatory burdens would probably not have been possible before the prospect of electricity price deregulation put the industry's economic future at stake.

"The constraint [on further power uprates] isn't NRC," says Vincent Gilbert, NEI's project manager for benchmarking the best nuclear plant practices for industry-wide adoption. "Everybody knows [plant managers have] got to go after their [capacity] margins to compete," he added, and the one-percent ECCS-related uprate is just "the minimum." The industry's problem now is that it doesn't know where the maximum safe margin reduction is. One company has asked the NRC for a 16% power uprate "just to see where the real margin is," Gilbert said.

How far can these margins be reduced and still maintain an adequate safety margin? Only more analysis will tell. When U.S. plants were first licensed to operate, "we were pretty conservative," says NRC reactor regulator Timothy Collins. "We didn't have the operating experience and analytical capabilities we have now, and plants were licensed at lower power levels than they needed to be. [Reactor] equipment was designed and warranted for higher power levels, and now [utilities] are just taking advantages of those conservative margins in the original licenses." Most licensees are now trying to do things to "flatten" the distribution of thermal power within the reactor core, he said, to demonstrate that the plant can produce more power without nearing design limits for fuel and reactivity. But typically, at some point, further power uprates will be limited by the size of the plant's turbine. "That's the biggest cost driver," says Collins.

The following table summarizes past and pending NRC approvals of uprated thermal power limits:

Figure 3

Past and Pending U.S. NRC Approvals
of Thermal Power Uprates
at Operating U.S. Reactors
(number of units)

Uprate Percentage (of originally-licensed thermal power limit)	Already Approved	Currently Pending
> 10%	4	0
5-10%	42	5
1-5%	4	1

Source: U.S. Nuclear Regulatory Commission staff, September 18, 2000.

Longer Fuel Cycles:

Numerous utilities are also making better headway in the reduction of outages for refueling and maintenance. To reduce the frequency of refueling outages, more plants are loading fuel designed for extended burnup to permit 18-month and even 24-month cycles. And more 24-month cores are under consideration, especially by BWR owners, according to NEI staff.

Under free market conditions, however, the key consideration for fuel cycle management is more likely to be the timing of the cycle rather than its duration. In many areas of the country with major seasonal variations in demand and available supply, the opportunity cost of a refueling outage during the highest price season has a bigger effect on the company's bottom line than the cost of any unused energy in the fuel. Thus, in California, for example, it makes most sense to refuel in spring, even if this means a shorter fuel cycle than originally planned, because significant sources of hydropower in spring make the replacement power cheaper and the lost revenue less than in the summer, when the plant can sell power at the highest prices of the year. "The cost of power is much more important than the cost of fuel," explained Suzanne Phelps, a nuclear fuel specialist at NEI.

Phelps cautioned, however, that consolidation of nuclear plant operations may dictate other considerations in fuel cycle management, this NEI specialist pointed out. As fewer companies acquire control of larger fleets of reactors, the availability of trained manpower becomes a more important factor for management decisions on the timing and length of fuel cycles and the management of multiple outages. “When you’re an Exelon and you’ve got maybe fifteen plants, you can’t have them all going down [for refueling] at once,” she said. “It would overwhelm your outage management staff.” Phelps predicts that organizations with larger fleets of reactors will want to buy fuel reloads for differing cycle lengths to stagger outages between spring and fall periods of relatively slack demand.

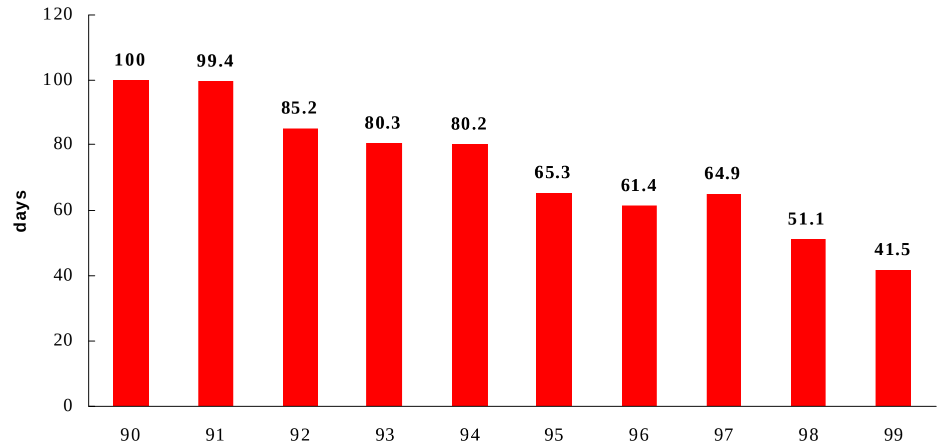
Clearly, NRC does not feel that safety considerations prohibit refueling cycles longer than 12 months. In the past, when the interval between refueling typically was 12 months, the principal limit on longer refueling cycles was not the fuel, but the maintenance and testing of the plant's safety-related equipment, according to NRC's Collins. Licensees had to demonstrate that either they could do the maintenance and perform the testing while the plant was on-line, or that the equipment was reliable enough that they did not need to do this work every 12 months. As licensees gathered more operating experience and successfully shouldered these burdens of regulatory proof, they eventually eliminated maintenance concerns as the principal limitation on extending the 12-month refueling cycle.

Shorter Outages:

As the time between refueling outages has lengthened, the duration of these outages has also declined significantly. In a recent *Nuclear News* survey of about a dozen U.S. plants that refueled this past spring, their time off-line fell from a recent average of 60 days to less than 40 this spring. Some plants have achieved 18-day outages, and most outage reductions are proving to be at least sustainable if not improving from year to year.Also, far fewer plants are shutting down for planned maintenance between refuelings. Of the dozen plants surveyed for the *Nuclear News* article on refueling practices, only one has plans for a mid-cycle maintenance outage.

The figure below from the Institute of Nuclear Power Operations shows that the past spring’s outages are consistent with an improving trend of several years’ duration.

Average Duration of Nuclear Refueling Outages in the US (1990-1999)



Source: Institute of Nuclear Power Operators (INPO)
Note: Average Values do not include data from shutdown units

Figure 4

Of course, outage managers are not planning to rest on their accomplishments to date. One such manager interviewed in the recent *Nuclear News* survey expects that the industry standard for refueling outages will soon be 30 days or less. Another went so far as to predict an average of less than 20 days industry-wide.

Plant managers may not be trying to win a race for the shortest refueling outage, however. For example, in an interview with Numark Associates, the Vice President of one of Duke Power's nuclear stations said he has found that the best results are achieved when the team focuses on the work that needs to be accomplished, rather than the budget available to carry it out or the outage length necessary to perform it. The bottom line is reliability, according to the Duke executive; a more reliable and safer plant is one that has shorter outages and lower costs in the long run.

The costs of improved outage planning are driving a growing trend toward more sharing of good practices and lessons learned across utilities. "Utilities will have to learn from each other in order to survive," said one manager. Some even credited the restructuring of power markets for the wider industry recognition that, while some nuclear plants may be competing with each other, the industry as a whole also has to compete with coal- and gas-fired generation. "[Restructuring] has increased the need to share information, and from what I've seen, all plants have been more than willing to share," said one outage manager. There are, of course, limits to cooperation among competitors; some plants are keeping outage start dates and durations confidential to protect their utility's financial standing.

Interestingly, the rising resource costs of outage management may also be contributing to the industry's consolidation by increasing the pressure on utilities with only one nuclear unit. One utility manager surveyed in the *Nuclear News* article said that "single unit stations cannot economically justify a large dedicated outage planning staff and must rely on matrixed resources."

Other outage managers surveyed by *Nuclear News* anticipate that as outage durations continue to decline, management focus will increasingly shift from saving time to saving costs. One obvious way to do that is to reduce worker doses. One outage manager predicted that the industry is heading toward a collective dose expectation ranging around 100 person-rem per outage. Another opportunity for cost-cutting could be preventive maintenance, said one respondent.

Finally, unplanned outages are focusing attention on improvements in maintenance practices, including early detection, monitoring, and corrective action on system degradation. Because these can best be addressed by sharing information among plant management and staff, equipment reliability is one of the projects in the NEI and INPO program to benchmark the best practices of leading plants for adoption by others.

"There's been a shift toward predictive maintenance, as opposed to preventive maintenance," said NEI benchmarking program manager Gilbert. "People are looking to cut back on planned [equipment] rebuilds and looking at using PRA's to try to detect when a system is about to fail, and catching it a few weeks before it actually does." More plants are using tomography and vibration analysis technology to provide data for improving these PRA's. These smarter maintenance techniques have yet to obtain NRC approval, however. "NRC hasn't told us what kind of detailed PRA they want [for these systems,] but they've told us, 'We'll know it when we see it."

Undaunted Demand for Capital Improvements:

Multi-million dollar capital equipment investments are evidence that nuclar operators believe the plants will remain competitive under deregulation. New steam generators for PWRs, for example, can reach an estimated $150 million per unit in total replacement costs. So far, deregulation has not had any notable chilling effect on utilities' willingness to make these "big-ticket" investments. We are aware of no reports that a utility is planning a premature shutdown of a PWR because the cost of replacement would make it uneconomic in competitive power markets.

To the contrary, deregulation may be more likely to increase utility SG investments in order to keep their plants running longer and more efficiently under extended operating licenses. Although such information is generally closely guarded for competitive reasons, we are aware of at least five utilities that have already applied both for license renewal and new steam generator units. At least 22 reactors are currently planning steam generator replacements.

Industry spending on digital instrumentation and controls (I&C) is also expected to increase as NRC approves generic approaches to the certification of software and hardware for use in different reactor designs. Because of their greater ability to process information and initiate protection functions compared to analog systems, digital systems can provide potential improvements in safety and reliability. The industry argued successfully for NRC to recognize this potential in its regulation for the licensing of new reactor designs.

Spending on software upgrades for new and existing equipment is one of the largest areas of current capital spending at nuclear plants. The U.S. nuclear industry spends about $1 billion annually on software, and about 18% of this -- $180 million -- is for application-specific "embedded" process software in I&C systems.

Outlook for Existing Plants:

As good as the U.S. nuclear power industry's performance has been so far, few industry leaders or analysts are ready to say it is good enough for competitive survival. Although U.S. operators this spring lopped 20 hours off average outage times of a year ago, a Commonwealth Edison executive says the industry will have to cut 20 more and that future outages should not exceed 20 days. The utility's current record is 18 days. Similarly, power generation costs will have to be cut in half, from 2 cents/kWh to 1, one leading fuel supplier analyst told colleagues at a recent World Nuclear Fuel Market annual conference. Utilities may not agree that such an ambitious goal is achievable. One engineering manager told us that “with the operating improvements we’ve already got in place, the delta of improvement from future [operating and capital equipment initiatives] is going to be a lot harder to get.”

Some utilities worry that with reactor life extensions, “the business will outlive our current workforce,” and plant managers will not be able to find enough nuclear engineers to replace the turnover from retiring ones. Other utilities, however, note that U.S. plants typically operate with more workers per megawatt than their European counterparts, and that, as one told us, “staffing will still have to be looked at carefully for cost savings.” These utilities also split on the question of managing plant obsolescence: one company engineer worried that so many of his plant’s former suppliers of original equipment have long since withdrawn from the nuclear business, while another anticipated that consolidation would give bigger genco's more buying power against the competing vendors still in the business. The uncertain added costs of long-term spent fuel storage also remain a concern for many plants.

Nevertheless, nuclear plant managers will continue to seek cost reductions to remain competitive with coal- and gas-fired units. In general, as long as domestic electricity prices continue to be set at the margin by coal- and gas-fired generation, and as long as significant nuclear safety incidents remain a thing of the past, the economics look good for continuing to run nuclear units as maximally and as long as NRC will allow. And thanks to risk-informed NRC regulation, NRC is allowing more opportunities for licensees to press these limits. This means, in turn, that there should be continuing healthy demand for operating initiatives and capital improvements that can be shown to improve performance without a safety penalty.

Prospects for New Plants

Some industry observers -- if they are willing to hazard a prediction at all -- believe the day when a U.S. utility will order a new nuclear power plant is still at least a decade away. Others, including NEI President Joe Colvin, are convinced that a new order may be no more than five years away. Colvin recently disclosed that NEI and five U.S. utilities have begun identifying "the conditions necessary" for building a new plant, and have met with suppliers, vendors, "policy people," and NRC. The U.S. will need between 300,000 and 500,000 MW of additional generating capacity in the years ahead, he said, and "nuclear needs to be and will be part of that mix." He also noted that the industry has enjoyed strong bipartisan support from Congress for some time.

It is unclear, however, just what kind of reactor a utility might order, and how big it might be. The past two years have seen an unexpected upsurge of vendor activities on new designs, largely as a result of DOE's Nuclear Energy Research Initiative (NERI) on a fourth generation of reactor designs. These "Gen IV" designs are to be safer, cheaper, less waste-producing, and more proliferation-resistant than existing “Gen II” light water reactors and "Gen III" advanced light water reactor (ALWR) systems. They include both passively-safe improvements on current large-scale ALWR's as well as smaller, modularized gas-cooled and other reactors designed to be "inherently" unable to reach core-melt temperatures or other unsafe conditions.

What potential customers will want, if anything, is far from clear. The most visible statement from a utility executive thus far came last June from Corbin McNeill, Chairman and CEO of PECO Energy, a leading acquirer of existing nuclear plants and partner in Exelon, the largest planned merger of U.S. generating assets. This nuclear industry leader told Congress that large new plants of 1400 MW or greater will not have a place in the competitive U.S. market of the future. U.S. utilities are more likely to be interested in smaller (~120 MW) modularized plants such as the Pebble Bed Modular Reactor (PBMR) design of the South African utility Eskom, he said, but their economic and safety advantages have yet to be sufficiently demonstrated. Since then, PECO has joined British Nuclear Fuels, Ltd. (BNFL) as an investor in the demonstration of Eskom’s PBMR. Plans call for starting construction of this demonstration facility in South Africa by mid-2001, with commercial operation by 2005. PECO has indicated that any new reactor design should have load following capability. This would favor smaller modular designs such as the PBMR.

Other promising small modular designs include the General Atomics Gas Turbine-Modular Helium Reactor (GT-MHR) and the Westinghouse-led International Reactor, Innovative and Secure (IRIS). Unlike Gen III's, however, none of these modular designs has been certified by NRC for construction. NEI's Colvin has pointed out that the need for NRC approvals makes it unlikely that the PBMR will be built in the U.S. for a number of years.

In contrast with PECO/Exelon, three out of three major nuclear operators recently interviewed by Numark Associates on this point stated that they do not share McNeill’s “small is beautiful” worldview. Executives at Entergy, a leading acquirer and operator of existing reactors, are convinced that in the competitive interconnected national grid of the future, the more megawatts a unit can generate, the more profitable it can be. Such a customer requirement would favor an improved, more cost-effective variant of a large ALWR design that is already certified by NRC, such as the Westinghouse AP-1000. A Duke Power executive agreed that larger units like the AP-1000 will be advantageous and predicted that consortia of nuclear generating companies will someday build large nuclear energy parks in areas of the country with the best access to major transmission arteries. He also emphasized the importance of maximizing the manufacturing of future plants in factories and minimizing on-site construction costs.

Whatever the future commercial prospects of the various reactor concepts, several things are clear about the outlook for new U.S. plant orders. First, the key to their competitiveness will be significant reductions in capital costs and construction times compared to current designs. Second, there will be no lack of demand for additional generating capacity in the U.S. market. Nationally, average reserve margins have declined substantially in recent years, from 14% in 1997 to a mere 9% last year. There should be room in this market for a vendor with the right reactor design.

Third, regardless of the design ultimately selected for a new order, we believe the investment climate for the next generation of nuclear plants will have to meet several other political and economic prerequisites. In addition to significant reductions in capital and even operating costs, these preconditions include:

- An operating record unblemished by any major safety problems at nuclear power plants anywhere in the world for several years running;
- Tangible progress on the management of nuclear waste, including firm and credible dates for actual movement of spent fuel off U.S. reactor sites; and
- Continuing high or volatile prices for natural gas.

Given the uncertainties, it is difficult to predict when a next wave of U.S. reactor orders would begin. It is tempting to say that at least ten years will pass before such time, but it is also easy to imagine a forward-looking major U.S. nuclear operator such as Exelon, Entergy, Nuclear Management Co., Duke Power or Dominion Resources deciding to place an order within this decade if the economics are right.

Either way, if new reactor designs fail to find customers in the United States over the next decade or two, it will be hard to blame deregulation. A new reactor hasn't been ordered in the United States since before the Three Mile Island accident in 1979, long before deregulation began in the mid-1990s. If anything, the prospect of open market competition has been a tonic for existing nuclear plants. As for new plants, deregulation is accelerating efforts to lower capital costs. If these efforts succeed and if safe operations, progress in the waste program and high gas prices continue their recent trends, the time will be ripe for new orders.

Deregulation has also shortened the investment horizons of electric generating companies. This might be enhancing the attractiveness of smaller, modular reactors to some operators, while others—probably the majority today—continue to believe in larger ALWR's. In the end, each generating company will have to weigh the lower financial risk of incremental investment in designs that are small and modular but still unproven, vs. the economies of scale and lower licensing risk of designs that have evolved from well proven technologies but that require larger investment commitments. But increasingly, the focus of the debate about future nuclear powerplants in the U.S. is shifting from the question of "whether" to the questions of "when" and "what kind."