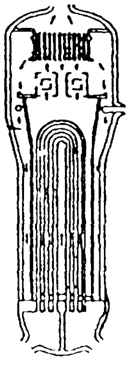
Economic Lives of Existing Nuclear Plants 3

All power plants, nuclear and non-nuclear, will eventually be retired. Each nuclear plant's economic performance (i.e., the cost of producing electricity while meeting Nuclear Regulatory Commission (NRC) and other safety requirements) plays a prominent role in plant life decisions. The cost and availability of alternative resources is also critical. Both the economic performance of nuclear plants and the cost of alternatives are debated, changing, and highly diverse. For this reason, economic life decisions are likely to be determined over time, as individual conditions change based on a host of separate decisions by utilities, State utility commissions, and Federal regulators. The cost of managing aging, while potentially large for some plants, is only one aspect of economic life decisions.

This chapter examines economic issues related to nuclear power plants. The discussion centers on the following:

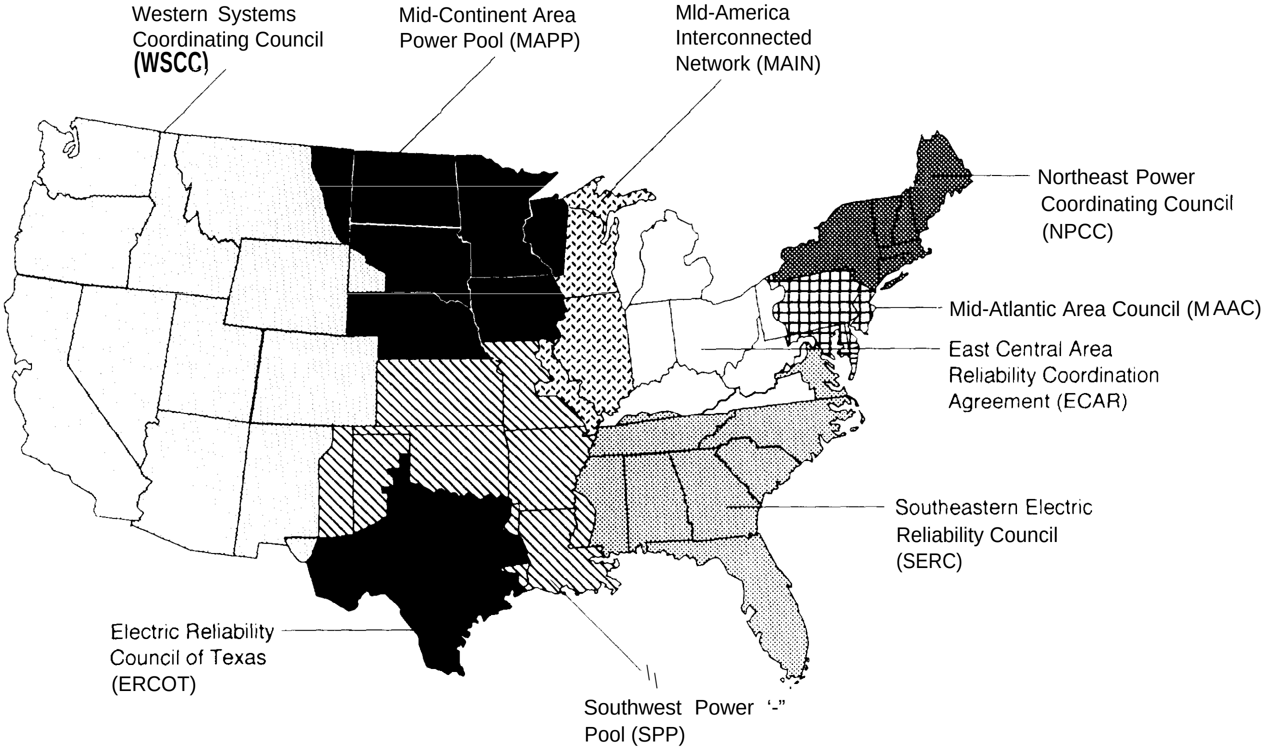
- the changing context of the electric utility industry as it relates to nuclear plant life decisions,
- institutions involved and their roles in evaluating the economic lives for existing nuclear plants,
- the economic performance of existing nuclear plants, and
- some factors affecting future nuclear plant cost and performance.



THE CHANGING ELECTRIC UTILITY CONTEXT

The electric utility industry is evolving rapidly. Pressures for change started two decades ago with widely fluctuating fuel prices, plummeting demand growth, hefty increases in the construction costs of large power plants, and increased attention to the environmental impacts of electricity generation. More recently, supply competition and utility energy efficiency efforts have increased markedly. These changes have reduced some of

Figure 3-l—Electric Regions in the Contiguous United States



SOURCE: U.S. Congress, Office of Technology Assessment, *Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition,* OTA-409 (Washington, DC: U.S. Government Printing Office, May 1989), p. 159.

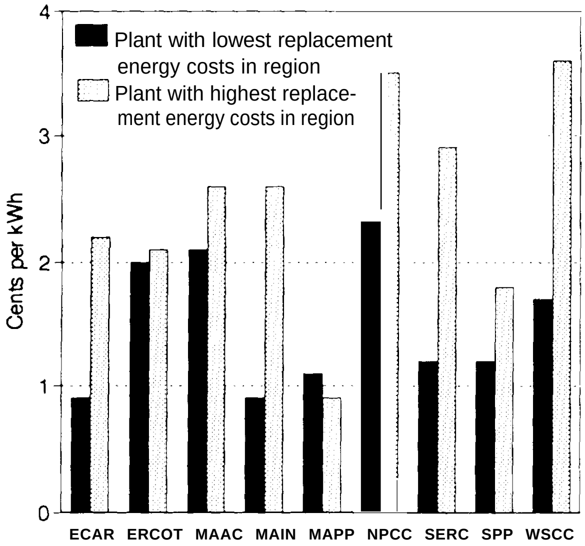
the costs of replacement power, placing additional economic pressures on existing nuclear and non-nuclear plants. Increasingly, utilities and their economic regulators are engaging in elaborate economic analyses and planning efforts known as integrated resource planning (IRP) or least-cost planning (LCP). The growing use of IRP both addresses and contributes to the changing utility context, as discussed later.

In addition to change, electric market conditions across the Nation are diverse. The electric power industry nationwide is subdivided by the nine regions of the North American Electric Reliability Council (NERC) (see figure 3-l), each comprised of many individual, but interconnected, utilities that often form separate power pools.[1] The U.S. electric power industry is a diverse and complex arrangement of investor-and consumer-owned utilities, government agencies, and independent power producers. Regional differences in generation reserve margins, fuel mix, and load growth reflect differing patterns of population, climate, economic activities, and the history of utility policy and regulation. One overall indicator of these differences is the range of regional values for replacement power, which vary widely across the country (see figure 3-2).[2]

[1] U.S. Congress, Office of Technology Assessment, *Electric Power Wheeling and Dealing: Technological Considerations for Increased Competition,* OTA-E409 (Washington DC: U.S. Government Printing Office, May 1989), ch. 6.

[2] J.C. Van Kuiken et al., *Replacement Energy Costs for Nuclear Electricity-Generating Units,* NUREG/CR-4012 (Washington DC: U.S. Nuclear Regulatory Commission October 1992).

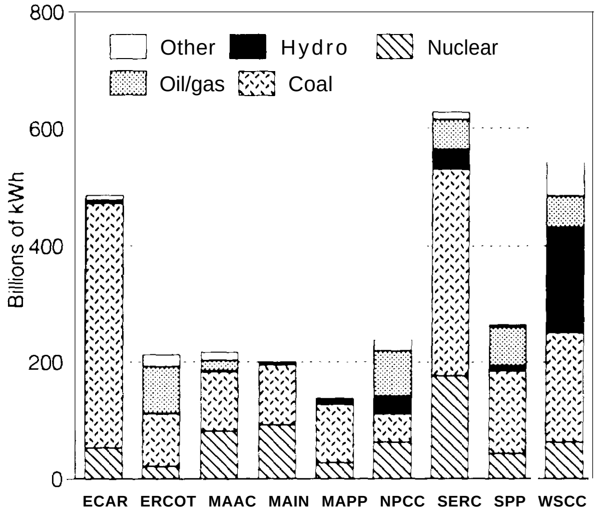
Figure 3-2—Diversity in Replacement Energy Costs **for Nuclear Power Within and Among Regions, 1992**



NOTE: These are estimated replacement energy costs for short-term nuclear plant outages for 1992.

SOURCE: J.C. Van Kuiken et al., *Replacement Energy Costs for Nuclear Electricity Generating Units*, NUREG CR-4012 (Washington, DC: U.S. Nuclear Regulatory Commission, October 1992), pp. 79-190.

Figure 3-3—U.S. Regional Electricity Supplies by Fuel, 1991



SOURCE: North American Electric Reliability Council, *Electricity Supply and Demand 1992-2001* (Princeton, NJ: NERC, June 1992), pp. 44-60.

These diverse factors can contribute to differing prospects for existing nuclear plants.

As shown in figure 3-3, the use of nuclear power differs greatly among U.S. regions. For example, in 1991, nuclear power supplied about 77 percent of the electricity in the Commonwealth Edison Co. (CECO) subregion of the NERC Mid-American Interconnected Network.[3] By contrast, there are no operating nuclear power plants in the Rocky Mountain Power Area subregion of the NERC Western System Coordinating Council.

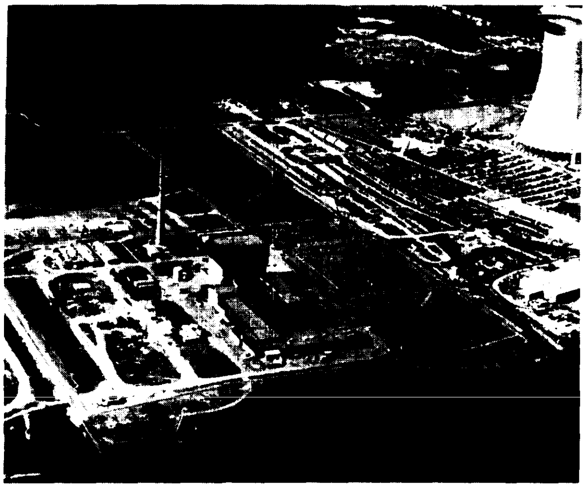
Electricity Demand and Capacity Margins

Slack electricity demand and surplus generating capacity have been among the factors noted in some nuclear power plant early retirement analyses. For example, owners of the retired Yankee Rowe plant noted that a regional recession turned a capacity constrained situation into one of excess capacity, reducing the need for the plant. Similarly, Niagara Mohawk's 1992 analysis of the Nine Mile Point Unit 1 plant indicated for the first time that early retirement might be economic, in large part due to a substantially higher forecast of the amount of non-utility generation available.[4] However, that forecast is uncertain and based on a now-repealed State law that provided a strong economic incentive to non-utility generators. In the case of the New York Power Authority's (NYPA) Fitzpatrick plant, NYPA's chairman noted that a planned non-utility generator was uneconomical and unnecessary, but if developed,

[3] North American Electric Reliability Council, *Electricity Supply & Demand 1992-2001* (Princeton, NJ: June 1992), pp. 44,46.

[4] Niagara Mohawk, ''Economic Analysis of Continued Operation of the Nine MiJe Point Unit 1 Nuclear Station,'' Nov. 20, 1992; and R.R. Zuercher, "Nine Mile Point-1 May Be Next to Fall to Unfavorable Nuclear Economics," *Nucleonics Week*, vol. 33, No. 49, Dec. 3, 1992, pp. 1, 14-15.

U.S. NUCLEAR REGULATORY COMMISSION



The Fitzpatrick Nuclear Power Plant in New York is among the plants that have reported facing increased economic pressures.

it would result in a surplus of capacity, making Fitzpatrick uneconomical.[5]

Nationwide, electricity consumption has continued to grow since the earliest nuclear power plants began operation (see figure 3-4). However, annual growth rates declined by nearly a factor of three between the 1960s and the 1980s. Capacity margins[6] remain high in many regions, because construction has been completed on plants begun years earlier under assumptions of more rapid growth (see figure 3-5). All but one of the nine NERC regions plan to reduce capacity margins over the decade.[7] Still, utilities and the Energy Information Administration (EIA) project that substantial amounts of new generating capacity (about equal to the total installed nuclear capacity) will be needed in most areas of the Nation during this decade.[8] However, much of this will be for meeting peak loads rather than for the baseload power supplied by nuclear plants. EIA projects that existing capacity will be fully used after 2000, and new baseload plants will then be required.

As the sharp, unexpected declines in demand growth between the 1960s and the 1980s demonstrated, predicting future demand can be highly uncertain. The EIA projects that annual electricity demand growth between 1990 and 2010 may range from 1.3 to 1.9 percent.[9] For context, even the small divergence between these estimates represents about 400 billion kilowatthours (kWh) in the year 2010, roughly two-thirds the electric output of all currently operating U.S. nuclear power plants. Moreover, such broad national averages may mask greater diversity and uncertainty at the regional level.

Competitive Resources

The emergence of a variety of low-cost electricity resources has already altered the economic outlook for nuclear power at several utilities. Two particularly prominent developments have affected competition for existing nuclear plants: 1) the increasing use of natural gas as a low cost and convenient fuel for new electricity generation; and 2) the recent surge in utility demand-side management (DSM) efforts,[10] a trend likely to continue given the large, untapped potential for

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[5] D. Airozo and R.R. Zuercher, "Gas Plant Competition Could Kill Fitzpatrick, NYPA Chief Claims," *Nucleonics Week*, vol. 33, No. 39, Sept. 24, 1992, p. 8.

[6] Capacity margins are the fraction of generating capacity in excess of peak demand available to provide for emergency outages, maintenance, system operating requirements, and unforeseen electricity demand.

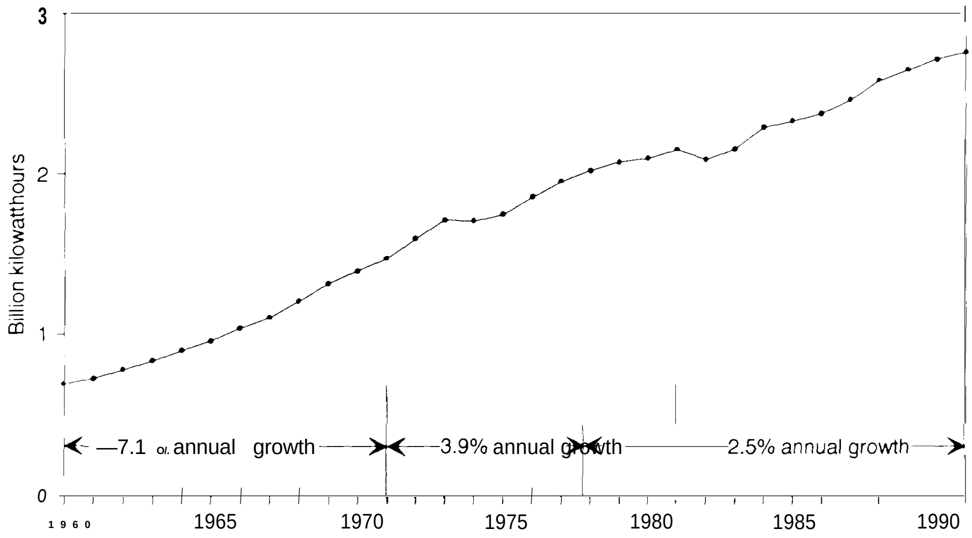
[7] North American Electric Reliability Council *Electricity Supply and Demand 1992-2001* (Princeton, NJ: June 1992).

[8] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1993, DOE/EIA-0383(93)* (Washington, DC: January 1993), p. 51.

[9] ibid., p. 49,

[10] For an indepth discussion of utility demand-side management, see U.S. Congress, Office of Technology Assessment *Energy Efficiency: Challenges and Opportunities for Electric Utilities*, forthcoming.

Figure 3-4—Electricity Sales, 1960-1991



SOURCE: U.S. Department of Energy, *Annual Energy Review 1991*, DOE/EIA-0384(91), June 1992, p. 219.

highly economic energy efficiency improvements.[11]

In the decision to retire the Trojan plant, Portland General Electric (PGE) assumed that new low-cost resources, primarily DSM, would be developed to replace the plant's output.[12] Notably, PGE's analysis projected that DSM could reasonably meet more than 10 percent of the utility's total energy requirements by the year 2012. Low-cost replacement power and prospective efficiency gains also played roles in the economic analyses of the San Onofre Nuclear Generating Station Unit 1 (SONGS-1).[13] The cost-benefits of needed capital additions at both of these plants were diminished, in part, because of determinations that gas-fired capacity and energy efficiency would be more economic over the long term. Similarly, in commenting on the outcome of the 1989 early retirement of the Rancho Seco plant, officials of the Sacramento Municipal Utility District have noted that reliance on natural gas and DSM have turned out to be economic choices.

Competition from natural gas generation or DSM has also been cited as challenging the economic prospects of other operating nuclear plants. For example, the operators of the Kewaunee plant determined that early retirement and replacement with a new gas-freed plant may be more economical than pursuing steam generator replacement in 1998, 15 years prior to license expiration.[14] For both the Fitzpatrick and Nine

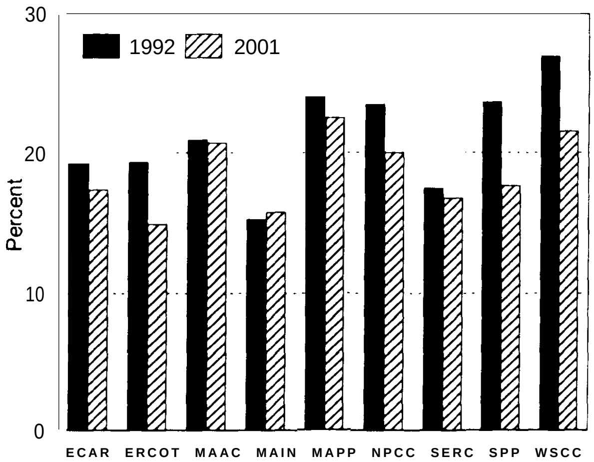
11 See U.S. Congress, Office of Technology Assessment, *Building Energy Efficiency*, OTA-E-518 (Washington, DC: U.S. Government Printing Office, May 1992); and U.S. Congress, Office of Technology Assessment, *Energy Efficiency in the Federal Government: Government by Good Example?*, OTA-E-492 (Washington, DC: U.S. Government Printing Office, May 1991).

12 Portland General Electric, *1992 Integrated Resource Plan*, Nov. 13, 1992, p. 4A.3.

13 E. Hiruo, "San Onofre-1 Shutdown Minks Era of Least-Cost Plans," *Nucleonics Week*, vol. 33, No. 47, Nov. 19, 1992, p. 7; J.J. Wambold, Manager of projects, Nuclear Engineering, Safety and Licensing, Southern California Edison Co., personal communication with OTA, Oct. 14, 1992; Portland General Electric, 1992 *Integrated Resource Plan, Nov. 13, 1992*, ch. 4a (Trojan Analysis).

14 D. Stellfox, "Risk of Premature Shutdown Grows; Kewaunee, Ft. Calhoun on Guard, " *Nucleonics Week, vol. 33, No. 36,* Sept. 3, 1992, pp. 1, I 1-12,

Figure 3-5-Current and Forecast Regional Capacity Margins, Summer 1992,2001



SOURCE: North American Electric Reliability Council, *Electricity Supply & Demand 1992-2&21* (Princeton, NJ: June 1992).

Mile Point plants discussed above, the planned or assumed nonutility generation capacity is expected to be fueled primarily by natural gas.[15] Noting the option of new gas-fired combustion turbines, Bonneville Power Administration has indicated that if performance at the Washington Public Power Supply System's nuclear plant does not improve within 2 or 3 years, it will consider alternatives to its 300-megawatt (MW) stake in the plant.[16]

Some analysts have raised questions about the future availability and cost of natural gas supplies.[17] U.S. electric utilities plan to add more natural gas-fired capacity than any other generating source in the next decade; the gas share is expected to total 54 percent of the nearly 60,000 MW utilities plan to add between 1992 and 2001.[18] By 2010, according to EIA projections, natural gas will generate more electricity in the United States than nuclear power.[19] Overall, projections of future natural gas prices will remain a subject of debate, and whether fixed-prices available in long-term gas contracts will remain low long enough to spur the early retirement of more nuclear units remains speculative.

Increasing competition in the electric power industry from independent power producers and wider transmission access are among the forces affecting the cost of replacement power and, thus, future plant economics.[20] Independent power producers, frost encouraged under the Public Utility Regulatory Policies Act of 1978 (PURPA)[21] and further encouraged by the Energy Policy Act of 1992 (EPACT),[22] have become a major force in the electric industry and account for a rapidly

15 D. Airozo and R.R. Zuercher, "Gas plant Competition Could Kill Fitzpatrick NYPA Chief Claims,' *Nucleonics Week*, vol. 33, No. 39, Sept. 24, 1992, p. 8; R.R. Zuercher, "Nine Mile Point-1 May Be Next to Fall to Unfavorable Nuclear Economics," *Nucleonics Week*, vol. 33, No. 49, Dec. 3, 1992, pp. 1, 14-15.

16 "Improve Nuclear Unit Performance O, Shut it Down, BPA Tells WPPSS," *Electric Utility Week*, May 31, 1993, p. 4.

17 North American Electric Reliability Council, *Reliability Assessment 1992-2001: The Future of Bulk Electric Supply in North America* (Princeton, NJ: September 1992), pp. 26-28; T. Moore, "Natural Gas for Utility Generation" *EPRI Journal*, vol. 17, No. 1, January/February 1992, pp. 5-1o.

18 North American Electric Reliability Council, *Electricity Supply & Demand 1992-2001: Summary of Electric Utility Supply & Demand Projections* (Princeton: June 1992), pp. 94, 101-107.

19 EIA Projects that natural gas will generate about 18 percent (or 735 billion kilowatthours), and nuclear power about 15.5 percent (or 636 billion kilowatthours), of U.S. electricity in 2010. These figures reflect the EIA reference (business-as-usual) case. U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 199-?: With Projections to 2010*, DOE/EIA-0383(93) (Washington, DC: January 1993), p. 49.

20 U.S. Congress, Office of Technology Assessment, *Electric Power Wheeling and Dealing: Technological Considerations for Increased Competition*, OTA-E-409 (Washington, DC: U.S. Government Printing Office, May 1989).

21 Public Utility Regulatory Policies Act of 1978, Public Law 95-617, Nov. 9,1978.

22 The Energy Policy Act of 1992, Public Law 102-486, Oct. 24, 1992.

growing share of new generation. Many States, utilities, and the Federal Energy Regulatory Commission (FERC) have sought to promote competitive bidding and independent power production.

Addressing Environmental Concerns

As with many industrial activities, electricity generation can cause major environmental impacts. Increasing attention to the environmental impacts of both fossil fuel combustion and nuclear generation creates a source of substantial uncertainty in future electricity markets. With respect to nuclear plant economics, two different types of environmental impacts are relevant:

1. the environmental benefits of reducing fossil fuel use, and
2. the environmental costs imposed by nuclear power plants.[23]

Utility IRP often includes scenarios investigating the impacts of such prospective environmental costs. In general, estimating and applying the economic costs associated with different types of environmental impacts is highly complex, remains a subject of substantial debate, but is a rapidly evolving field.[24]

Two major environmental concerns related to fossil fuel combustion may improve the relative economic attractiveness of existing nuclear plants: global climate change and acid deposition.[25] All fossil fuel power plants produce carbon dioxide (CO_2), a gas that many experts believe may contribute to severe global climate change if not controlled in coming decades.[26] U.S. CO_2 emissions represent about 20 percent of total annual global emissions, with electric utilities responsible for about one-third of this amount. In a recent report, OTA estimated that under present conditions the annual carbon emissions from U.S. electrical utilities to the Nation's total could increase to as much as 45 percent by 2015.[27]

Predicting what future efforts will be taken to address CO_2 emissions remains speculative. However, efforts to control these emissions could have profound impacts. For example, consider a hypothetical $100 per ton carbon tax, which one Congressional Budget Office study estimated could potentially reduce CO_2 emissions between zero and 25 percent from current levels over a 10-year period .28 Such a tax alone would translate into approximately $0.03/kWh for coal-fired electric generation, more than the average operational costs at existing nuclear power plants. The prospective cost of controlling CO_2 emissions is increasingly being considered in IRP. The resulting impacts can determine the economic attractiveness of a plant. For example, in its analyses of early retirement for the Trojan nuclear plant, PGE examined CO_2 tax scenarios of $0, $10, and $40 per ton.[29] While the analyses showed that a high CO_2 tax would make continued operation the

23 The NRC's environmental assessment of the license renewal rule discussed the costs of continued nuclear plant operation. U.S. Nuclear Regulatory Commission, *Environmental Assessment for Final Rule on Nuclear Power Plant License Renewal,* NUREG-1398, October 1991.

24 See, e.g., Pace University Center for Environmental Legal Studies, *Environmental Costs of Electricity* (New York, NY: Oceana Publications, 1990).

25 Other resources, such as renewable energy and energy efficiency measures, do not produce CO_2 emissions and would also have relatively improved economics. Natural gas and petroleum-fired generation produce about half the CO_2 per unit of electricity as does coal and could be affected as well. The dominant role of coal, which supplies 55 percent of the Nation's electricity, makes it likely that aggressive action to control CO_2 emissions would affect all aspects of the electricity market.

26 See, generally, J.B. Smith and D. Tirpak (eds.), Office of Policy, Pl arming and Evaluation, U.S. Environmental Protection Agency, *The Potential Effects Of Global Climate Change On The United States, EPA-230-05-89-050* (Washington DC: December 1989).

27 U.S. Congress, offic e of Technology Assessment, *Changing by Degrees: Steps to Reduce Greenhouse Gases,* OTA-O-482 (Washington, DC: U.S. Government Printing Office, February 1991), pp. 3, 25.

28 U.S. Congress, Congressional Budget Office, *Carbon Charges as a Response to Global Warming: The Effects of Taxing Fossil Fuels* (Washington, DC: U.S. Government Printing Office, August 1990).

29 A tax of $40 per ton of CO_2 1S equivalent to a &LX of $147 per ton "C.

most economic option, PGE viewed that future as having a low probability of occurrence.[30]

Fossil-fired power plants are also responsible for sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions leading to acid deposition. SO_2 emissions and acid rain have serious, but generally local or regional, effects: surface water acidification, fish losses, forest damage and decline, materials and cultural impacts, reduced visibility, and both direct and indirect human health effects.[31] Of the estimated 23 million tons of SO_2 emitted in the United States in 1987, over two-thirds stemmed from electric utilities.[32] Electric utilities are also responsible for about one-third of the 18.6 million tons of NO_x emitted annually in the United States.[33] The NO_x controls and SO_2 emission ceilings and emission trading provisions of the Clean Air Act Amendments of 1990 (CAAA)[34] may have large but still unclear economic impacts on some existing coal plants.[35]

In contrast to the environmental challenges of fossil fuel combustion involving large volumes of SO_2, CO_2, NO_x, and coal ash, unique environmental challenges of nuclear plants involve relatively small volumes of materials with sometimes high levels of radioactivity. Although most of the volume of radioactive waste from nuclear plants contains very low levels of radioactivity, handling, managing, and disposing all radioactive waste from nuclear plants can be difficult and costly. One potential environmental cost of nuclear plants that has been raised in IRP, in addition to waste disposal, is the low probability, but high consequence, risk of a nuclear plant accident. For example, as part of its IRP, PGE estimated the expected environmental costs associated with nuclear plant accidents to be between zero and about one-half cent per kWh.[36] This estimate assumed that the maximum amount of potential damage is no more than $35 billion, several times more than the approximately $7 billion liability limit set by the Price Anderson Act.[37] For conservatism, PGE assumed the risk to be 1/1000 per reactor year of operation. Others have estimated both higher and lower expected environmental costs. For example, a Pace University Center for Environmental Legal Studies report estimated a cost of about 2.3 cents/kWh[38], while one study for Yankee Atomic Electric Co. estimated a cost nearly three orders of magnitude less.[39]

There are other environmental impacts with less sweeping national implications that may have important impacts on plant economics. All nuclear and fossil steam power plants can raise the temperature of the local cooling water used, producing thermal plumes and altering oxygen demands, both of which can affect aquatic life near power facilities. For example, one analysis

30 Portland General Electric, *1992 Integrated Resource Plan, Nov.* 13, 1992, p. 4A.3.

31 *National* Acid Precipitation Assessment Program, 1990 *Integrated Assessment Report* (Washington, DC: November 1991).

32 Ibid., p. 198.

33 Based on an estimate for 1985. National Acid Precipitation Assessment Program, 1989 *Annual Report of the National Acid Precipitation Assessment Program* (Washington, DC: June 1990), p. F-43,

34 Clean Air Act Amendments of 1990, Public Law 101-549, Nov. 15, 1990, Tide IV.

35 U.S. Department of Energy, Energy Information Administration, *Annual* Outlook *for U.S. Electric Power 1991: Projections Through 2010*, DOE/EIA-0474(91) (Washington, DC: July 1991), p. 25.

36 In addition, other external nuclear environmental costs associated with waste disposal, routine operations, and fuel mining and processing were estimated to total about 0.15 cents/kWh. Portland General Electric, *1992 Integrated Resource Plan, Nov. 13, 1992,* app. 7.

37 42 USC 2208 *et. seq.*

38 *pace* University Center for Environmental Legal *Studies, Environmental Costs of Electricity*, 1990.

39 Energy Research Group, Inc., "*Environmental* Externalities and Yankee Nuclear Power Station," November 1991, as reported in Portland General Electric, 1992 *Integrated Resource Plan Nov. 13, 1992,* app. 7.

of the impact on the marine environment from operation of SONGS-1 estimated an economic loss of about $6 million annually.[40] Coal plants produce vast volumes of ash, which is often laced with heavy metals and radionuclides. Hydropower, the major renewable source of electrical energy currently used in the United States, can also have major impacts, mainly by flooding large areas and causing perturbations in stream flows, fish migrations, water temperatures, and oxygen levels.

INSTITUTIONAL ISSUES IN NUCLEAR PLANT ECONOMIC LIFE DECISIONS

The objectives in nuclear plant life decisions stem from broader electric power system objectives, including the following:

- assuring adequate supplies to meet demand;
- minimizing the costs of electricity (including, increasingly, environmental costs);
- equitably treating both electricity consumers and plant owners in the recovery of costs; and
- increasingly, responding to intensifying market forces in the electric power industry.

Responsibility for the economic performance of existing nuclear power plants lies with the utilities owning and operating them.[41] So, too, does the ultimate responsibility for economic decisions regarding nuclear power plant lives.

Industrywide groups such as the Nuclear Management and Resources Council (NUMARC), the Institute of Nuclear Power Operations (INPO), the Electric Power Research Institute (EPRI), and the Edison Electric Institute (EEI) address issues related to plant economies as well. For example, INPO, NUMARC, EEI, and EPRI are participating in an "Industrywide Initiative' to improve nuclear plant economic performance.[42] NUMARC's principal role is to identify and eliminate unnecessary or inefficient NRC regulatory activities leading to unnecessary costs .[43] EEI is helping utilities address economic regulatory issues, including application of IRP. EPRI's principal role is to assist utilities with the application of proven technology to reduce costs and achieve benefits in plant reliability, productivity and thermal efficiency. In addition, EPRI is continuing its two decade research effort to develop more economic technologies for safe operation and maintenance (O&M) of existing nuclear power plants.[44]

All but about 8 of the 107 operating nuclear plants in the United States are primarily owned by investor-owned utilities and fall under FERC or State economic regulation.[45] For these plants, economic decisions are typically made by the plant owners in conjunction with the respective

40 California Public Utilities Commission, Division of Ratepayer Advocates (CPUC DRA), ' 'Report on the Cost-Effectiveness of Continued Operation of the San Onofre Nuclear Generating Station Unit No. l," Investigation 89-07-004, Sept. 25, 1991. According to CPUC DRA staff, revised cost estimates of marine damage indicate that the cost is higher, on the order of $15 million annually. Robert Kinosian, CPUC Division of Ratepayer Advocates, letter to the Office of Technology Assessment, Feb. 8, 1993.

41 Nearly half of the 108 operating nuclear power plants are jointly owned by hvo or more utilities. The remainder are solely owned. In total, over 130 utilities have some share of existing plants. R.S. Wood, U.S. Nuclear Regulatory Commission, *Owners of Nuclear Power Plants, NUREG-0327, Rev. 5 (Washington, DC: July 1991). For those, economic decisions are shared by the owners.*

42 ''EEI TO Help Nuclear Move Ahead in Changing power Marketplace, ' *Nucleonics Week,* vol. 34, No. 25, June 24, 1993, pp. 1,12-13.

43 Nuclear Management and Resources Council, *Review of Operations and Maintenance Costs in the Nuclear Industry,* NUMARC 92-03 (Washington DC: December 1992), pp 54-56.

44 See, e.g., Grove Engineering, Inc., *Long-Term Capital Planning Considering* Nuclear *Plant Life-Cycle* Management, EPRI TR- 101162 (Palo Alto, CA: Electric Power Research Institute, September 1992).

45 Five of the Nation's 108 operating nuclear power plants are publicly owned (e.g., by a public power authority or rural Cooperative). Three others are owned by the Tennessee Wiley Authority (TVA), and are not subject to FERC or State economic regulation. TVA also has two previously operating units with full power licenses under review (Browns Ferry 1 and 3), Many public power utilities also share joint ownership of existing nuclear plants operated by investor-owned utilities.

economic regulatory bodies.[46] While economic regulatory activities vary greatly by State, many States play a strong role in promoting and applying economic analyses to utility investment and retirement decisions. For example, many States require their respective utilities to perform IRP.

The public also has a role in the regulatory activities related to plant economics. For example, the definition of IRP in the Energy Policy Act of 1992 (EPACT) specifically requires including public participation and comment in development of the plan.[47] The public may also raise economic issues in NRC licensing actions. For example, following the request of Pacific Gas and Electric Co. (PG&E) to extend the license expiration dates for the Diablo Canyon nuclear plants by recapturing the plants' construction periods (see ch. 2), one public interest group and the State of California received NRC approval to intervene in the case.[48] The opposition was not related to plant safety, but rather to a concern that extended operation would increase electricity rates and harm the State's economy.

Integrated Resource Planning and Nuclear Plant Economic Analyses

Nearly all States that regulate nuclear utilities require IRP already and all will eventually consider its use, as required by EPACT.[49] EPACT also requires the Tennessee Valley Authority to perform LCP in making resource decisions. While IRP is not necessarily directed at examining nuclear plant life decisions, it can and has been. For example, PGE's decision to retire the Trojan nuclear power plant was examined and supported in PGE's 1992 Integrated Resource Plan, a planning exercise required by the Oregon Public Utilities Commission.[50] Also, the New York Public Service Commission has required regulated utilities in the State to examine the economics of continued nuclear plant operation.[51]

Change and uncertainty are hallmarks of the electric utility industry's planning challenge. For this reason, planning methods generally consider a range of possible scenarios rather than attempt to forecast accurately inherently uncertain future conditions. For example, in its analysis of the economics of continued operation or early retirement for the Trojan plant, PGE examined a range of natural gas prices, electrical demands, and plant costs and performance. Depending on the assumptions used, PGE's probabilistic analysis indicated a range of net present value of continued operation between -$1.8 billion to +$ 1 billion (see figure 3-6).[52] This wide range of possible outcomes suggests that plant life decisions may depend on highly uncertain factors.

Because many factors in economic analyses are inherently uncertain, disagreements about appropriate decisions should not be surprising. Rather than finding one clearly optimal choice, plant economic decisions involve professional judgments that attempt to balance alternative choices and their uncertain outcomes. Some have sug-

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46 In some cases (e.g., utility holding companies), economic regulation of utility performance rests with both the State utility commission and the Federal Energy Regulatory Commission. For a discussion of Federal and State jurisdiction% see U.S. Congress, Office of Technology Assessment *Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition,* OTA-E-409 (Washington, DC: U.S. Government Printing Office, May 1989), ch. 2.

47 Energy Policy Act of 1992, Public Law 102-486, Sec. 111.

48 Federal Register Feb. 2, 1993, pp. 6827-8.

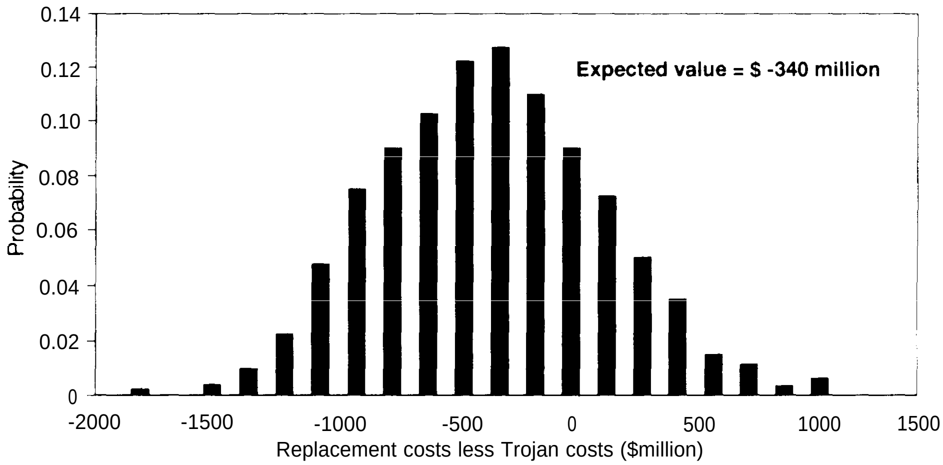
49 Energy policy Act of 1992, Public Law 102-486, Sec. 111. See also, U.S. Congress, Office of Technology Assessment, *Energy Efficiency: Challenges and Opportunities for Electric Utilities,* forthcoming.

50 Portland General Electric, *1992* Integrated *Resource Plan,* Nov. 13 1992.

51 See, for example, Niagara Mohawk, "Economic Analysis of Continued Operation of the Nine Mile Point Unit 1 Nuclear Station," Nov. 20, 1992.

52 The expected value of continued operation was a loss of $340 million in 1992 dollars, based on the estimated probabilities of different scenarios. Portland General Electric, 1992 *Integrated Resource Plan Nov. 13,* 1992, p. 4A.5.

Figure 3-6-Trojan Plant Economic Analysis Results



SOURCE: Portland General Electric, 1992 *Integrated Resource Plan, Nov.* 13, 1992.

gested that certain past State regulatory activities leading to plant retirement reflected an antinuclear bias rather than solid economic analysis. For example, commenting on IRP, one industry leader argued that "the process is subject to abuse, and extremely sensitive to bias, and that the economic analyses for SONGS-1 and Trojan plants were manipulated to retire these plants.[53] Though any planning process involving the complex and uncertain factors found in the utility industry is subject to manipulation, past economic decisions provide no compelling evidence of regulatory bias. In the Trojan case, for example, the utility itself determined that early retirement was the best option. In the SONGS-1 case, the owning utility argued that continued operation would be economic, but declined to pursue a proposal to place the risks and rewards of plant costs and performance on the utility.

▮ Treatment of Unrecovered Capital in Early Retirement

There is limited precedence in the economic regulation of the electric industry to guide the financial treatment of capital invested, but not yet recovered in rates, following the early retirement of a plant. Similarly, there is little precedent for the treatment of shortfalls in decommissioning funds resulting from early retirement. This is true for FERC as well as State regulation. For example, the only precedence for treatment of costs for the retired Yankee Rowe plant were two 1988 decisions for plant abandonment. However, those were plants canceled during construction, not abandoned operating plants .54 Of the six recent early retirement decisions, unrecovered capital and decommissioning costs ranged from a few hundred million dollars for most to over $4 billion for one. Allowing a utility to recover its capital costs in an early retirement is consistent with the traditional regulatory approach in which the prudence of the plant investment is determined when the plant becomes operational. However, in those retirement cases where plant performance was poorer and costs were substantially higher than originally anticipated, State PUCs may consider whether the utility performed adequately

53 Phillip Bayne, "Nuclear Power in 1992: A Year-End Review, " remarks to *The Energy Daily's* Annual Utility Conference, Dec. 10, 1992.

54 "FERC Okays Yankee Rate Hike But Eyes 'Prudence' of Shutdown," *Nucleonics Week, vol. 33, No. 37,* Aug. 6, 1992, pp. 4-5.

during the operating life of the plant and whether some cost disallowances are warranted.

Anticipated regulatory treatment of decommissioning and historical plant costs can weigh in the economic attractiveness to a utility of early retirement. As with the application of IRP, some have argued that State regulators' treatment of capital recovery in early retirement decisions for the SONGS-1 and Trojan plants were intended to "encourage their acquiescence."[55] SONGS-1 was retired in 1993 after 26 years of operation under an agreement between the California Public Utilities Commission (CPUC) Division of Ratepayer Advocates (DRA) and the owners of the unit (Southern California Edison (SCE) and San Diego Gas and Electric Co.). The agreement provided the utilities full recovery of the remaining $460 million in capital costs over an accelerated 4-year period rather than the remaining 15 years in the licensed life. In addition, about $29 million that had been excluded from the utilities' rate bases pending further review was returned to the utilities.[56] The utilities' rates of return on the $460 million during the 4-year recovery, however, was reduced from 12 percent to 8 percent.

Not all commissions have allowed recovery of historical capital costs in early retirement decisions. Public Service of Colorado's (PSCO) Fort St. Vrain (FSV) plant is a case in point. The unit was built with about $1 billion in joint funding from PSCO, the Atomic Energy Commission, and General Atomics Technologies. After beginning commercial operation in 1979, the unique high-temperature gas reactor experienced major operational difficulties, including problems with the control rod drive assemblies and the steam generator ring headers, low plant availability (about 15 percent), and prohibitive fuel costs.[57] In 1986, PSCO, the Colorado Public Utilities Commission, the Colorado Office of the Consumer Counsel, and other parties agreed to remove FSV's $600 million remaining capital costs from the utility's rate base.[58] However, the plant continued to operate under a performance incentive rate, giving PSCO both the risks of poor performance and the rewards of good performance. With FSV's economic problems continuing, PSC retired the plant in 1989.[59]

Other Economic Regulatory Incentives

Many States have established direct economic incentives for plant performance. As of 1989, about 70 nuclear plants operated under some type of explicit economic incentive program.[60] These incentives typically use specific formulas to measure management efficiency and plant performance and relate those to financial rewards or penalties. Most incentive programs use capacity factors (CFs)[61] as the primary measure of performance, although other measures are also found,

55 P. Bayne, "Nuclear Power in 1992: A Year-End Review," remarks to *The Energy Daily's Annual* Utility Conference, Dec. 10, 1992.

56 California PUC, Decision 92-08-036, Aug. 11, 1992, p. 3.

57 Public Service Company of Colorado, Proposed *Decommissioning Plan for the Fort St. Vrain Nuclear Generating Station,* Nov. 5, 1990, pp. 1.1-1 to 1.1-2.

58 Unrecovered capital costs included original construction costs of $200 million and later capital additions of $400 million. OTA staff conversations with Colorado Public Utility Commission staff, Aug. 25, and Sept. 24, 1992.

59 In particular, due to FSV's unique nature (i.e., the only commercial gas reactor), the fuel costs were substantial. The cost of fuel in 1989 would have been approximately 2.8 cents per kWh. At the same time, PSC could generate coal-fired power for 2.7 cents per kWh and could purchase power for only 2.2 cents per kWh. Donald Warembourg, Site Manager, Fort St. Vrain Nuclear Station, Public Service Company of Colorado, personal communication, Sept. 23, 1992.

60 R.L. Martin, P. Hendrickson and J. Olson, *Incentive Regulation of Nuclear power Plants by State Public Utility Commissions,* NUREG/CR-5509 (Washington, DC: U.S. Nuclear Regulatory Commission, December 1989). NRC tracks State economic incentive programs to evaluate their potential impact on safety.

61 Capacity factor is a measure of a plant's actual production of electricity as a percentage of maximum possible production and is defined as the ratio of the electricity produced to the rated capacity of the facility.

such as the heat rate (the plant's thermal efficiency), NRC's Systematic Assessment of Licensee Performance (SALP) scores, and NRC performance indicators. Incentives for improving plant operating cost are not limited to nuclear power plants. For example, incentive based ratemaking has been included in decisions for non-nuclear activities Columbus Southern Power in Ohio.[62]

Incentive programs have generally involved relatively small dollar values relative to total plant costs. Many of the incentive programs had awarded no penalties or rewards during the several-year period reviewed in one NRC report.[63] The largest penalty reported was a 2-year cumulative $32-million penalty for Public Service Electric and Gas (PSE&G) resulting from an extended forced outage at the two Peach Bottom units, of which PSE&G owns 42 percent.[64] In comparison, during that 2-year period, PSE&G's share of O&M costs for the two plants was far larger, over $200 million.[65]

In contrast, PG&E's Diablo Canyon Units 1 and 2 have a performance-based rate designed to place the risks and rewards for plant performance on the utility rather than on the ratepayers.[66] The unconventional rate established by the CPUC in 1988 allows PG&E to receive payments based on actual plant output rather than on plant construction and operational costs. Since the rate was established, the plants have performed far more reliably than had been assumed in the CPUC's and PG&E's analyses. Average CFs, at about 83 percent, have surpassed the assumed 58 percent, and payments to PG&E between 1989 and 1991 were about $4.1 billion, or about 40-percent higher than the $2.9 billion originally anticipated.[67] The performance-based rate approach results in plant economic life decisions being made more independently by PG&E and less in conjunction with the CPUC.

The performance-based approach has been suggested for other nuclear plants but not adopted to date. For example, as an alternative to SONGS-1 early retirement, the DRA proposed establishing a performance-based ratemaking treatment of future costs.[68] Noting that SCE did not pursue the proposal, the CPUC found that it "would be novel and complex, might create perverse incentives, and would require much time to work out.' '[69] Similarly, in 1989 Consumers Power Co. proposed selling its Palisades plant to a new entity, the Palisades Generating Co. (PGC), to be owned by Consumers Power, the Bechtel Power Corp., and a Westinghouse Electric Corp. subsidiary.[70] Prior to 1989, the Palisades plant performance had been well below the industry average, with problematic steam generators (SGs) leading to a lifetime CF of 48 percent. PGC would have sold its power to Consumers Power under a long-term purchase contract and accepted the risks and rewards of plant cost and performance. However, FERC and the State of Michigan

62 "Ohio PUC to Consider Incentive Ratemaking for O&M Activities, " *Electric Utility Week,* Sept. 21, 1992, pp. 16-17.

63 R. L Martin, P. Hendrickson and J. Olson, *Incentive Regulation of Nuclear Power Plants by State Public Utility Commissions,* NUREG/CR-5509 (Washington DC: U.S. Nuclear Regulatory Commission, December 1989).

64 U.S. Nuclear Regulatory Commission, *Owners of Nuclear power Plants,* NUREG-0327; *Rev.* 5. (Washington, DC: July 1991), p. 6.

65 U.S. Department of Energy, Energy Information Administration, *An Analysis of Nuclear Plant Operating Costs: A 1991 Update, DOE/EIA-0547* (Washington, DC: May 1991), p. 59.

66 California Public Utilities Commission, Decision 88-12-083, at 282.

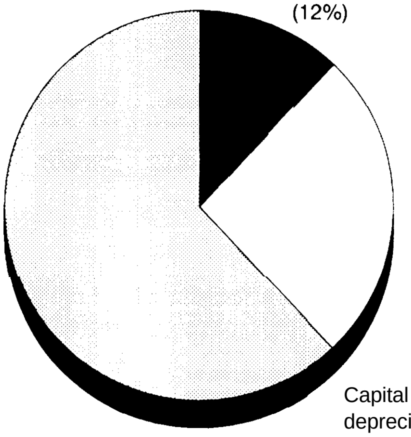
67 Toward Utility Rate Normalization, "Petition of Toward Utility Rate Normalization for Modification of Decision 88-12 -083,' Sept. 17, 1992, pp. 7-11.

68 California Public Utilities Commission Division of Ratepayer Advocates, "*Report* on the Cost-Effectiveness of Continued Operation of the SONGS Unit No. l," Investigation 89-074X)4, Sept. 25, 1991, pp. 45-52.

69 California Public Utilities Commission Decision 92-08-036, Aug. 11, 1992, p. 23.

70 Federal Energy Regulatory Commission "Initial Decision on Applications for Approval of a power purchase Agreement and the Sale of Certain Transmission Facilities, " 59 FERC 63,023, June 17, 1992.

Figure 3-7—Average Nuclear Power Plant Costs, 1990



Total 5.97 **cents per kWh**

SOURCE: U.S. Department of Energy, Energy Information Administration, *Electric Plant Cost and Power Production Expenses 1990,* DOE/EIA-0455(90) (Washington, DC: June 1992), p. 14.

decided the details of the proposed transfer and purchase power arrangements were not in the public interest.[71] Among the concerns, the proposed purchase power rates were found to be excessive, having been based on an assumed 55-percent CF, far lower than the average 74 percent produced in 1991 and 1992 following the replacement of the plant's SGs.

ECONOMIC PERFORMANCE OF NUCLEAR PLANTS

Each nuclear power plant has its own unique history of cost and performance that differs from industry averages. Large year-to-year fluctuations in costs are common for most nuclear plants as capital additions are undertaken and completed. Plant availability also varies from year to year as the plants undergo refueling and planned maintenance during 12- to 24-month refueling cycles. Also, unplanned repair outages contribute to cost and performance fluctuations.

Economic life decisions are plant specific. In evaluating the future economic prospects of any plant, the owners focus on the unique circumstances of that plant-its cost and performance, and the demand for, and value of, electricity in the region. While broad industry trends may be helpful in projecting future cost and performance of any particular plant, they do not determine the cost-effectiveness of a plant.

Three types of nuclear power plant costs can have important and distinct roles in determining the economic life of individual units:

1. historical capital costs,
2. future capital additions, and
3. annual O&M and fuel costs.

Capital-related costs in the United States on average are the largest component of total nuclear power plant costs, about 60 percent higher than O&M and fuel costs combined (see figure 3-7).[72] Together with the plant's CF, these costs characterize a plant's economic performance.

Plant Capacity Factors

Reliability and availability are important factors in nuclear plant life decisions. A plant's CF has a large impact on plant economy, since as more electricity is produced (i.e., as the CF rises) fried costs are spread over more kilowatt-hours, reducing the average cost. In the case of SONGS-1, Trojan, Rancho Seco, and FSV, CFs well below the industry average contributed to early retirement decisions. For example, SONGS-1 had a lifetime CF of about 56 percent, and the 5-year average prior to the retirement decision was only 44 percent. The lifetime CFs for Trojan and FSV were about 55 and 15 percent, respectively.

71 Ibid.; and Michigan Public Service Commission, Opinion and Order, Case Nos. U-9507 and U-9794, June 12, 1992.

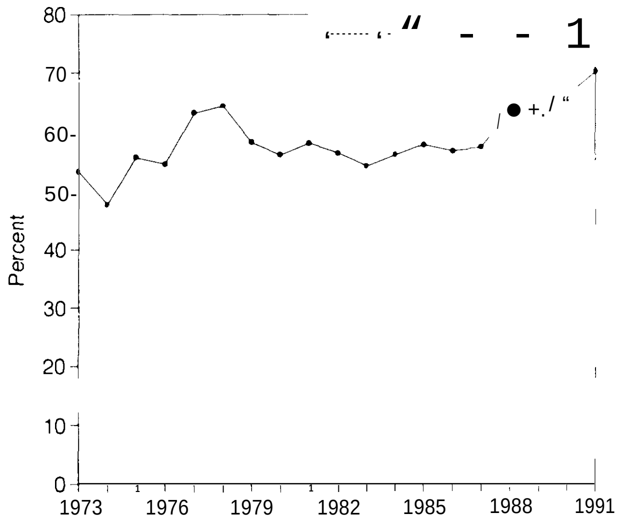
72 U.S. Department of Energy, Energy Information Administration, *Electric Plant Cost and Power Production Expenses 1990,* EIA-0455(90) (Washington DC: June 1992), p. 14.

Future CFs at any plant are uncertain and thus subject to disagreement in economic analyses. For example, based on its analyses of other plants and effects of planned and completed maintenance activities, SCE suggested that reasonable CF scenarios for SONGS-1 ranged from 60 to 80 percent. In contrast, the DRA considered a range of 44 to 70 percent more likely based on its assessment of other plants and prospects.[73] Similarly PGE considered CFs ranging from O percent to over 80 percent in its analyses of Trojan, with an expected value of about 60 to 64 percent, depending on the replacement of SGs.

Average CFs at U.S. nuclear facilities have increased substantially in the past few years from an historical average of under 60 percent to over 70 percent in 1991 (see figure 3-8).[74] INPO has set an industry-wide median CF goal of 80 percent by 1995, which it views as a challenging but achievable target.[75] Nuclear plants do not operate continuously for several reasons:

- to allow for refueling outages, which typically require several weeks at least once every 2 years;
- for planned plant maintenance and capital additions (discussed below), which are performed concurrently with refueling to the extent possible, but often involve additional time;
- for equipment failures causing unscheduled maintenance; and
- for other operational problems (e.g., if plant operators fail to pass annual NRC qualification tests).

Figure 3-8-Average U.S. Nuclear Power Plant Capacity Factors, 1973-1991



SOURCE: U. S. Department of Energy, Energy Information Administration, *Annual Energy Review 1991* DOE/EIA-0384(91) (Washington, DC: June 1992), p. 237.

The need to refuel and conduct maintenance every 1 to 2 years creates a practical limit to overall CFs of about 80 to 90 percent over a cycle.

One EIA analysis identified three factors that contributed to the lower CFs of the 1980s, including increased safety and regulatory requirements, degradation of major equipment, and management problems.[76] Many of the safety-related outages resulted from NRC's Three Mile Island (TMI) action plan,[77] involving shutdowns for plant modifications and safety audits. EIA noted one series of EPRI reports that estimated that NRC regulatory actions accounted for about

73 California Public Utilities Commission, Division of Ratepayer Advocates, "Report on the Cost-Effectiveness of Continued Operation of the SONGS Unit No. l," Investigation 89-07-004, Sept. 25, 1991, pp. 6-10.

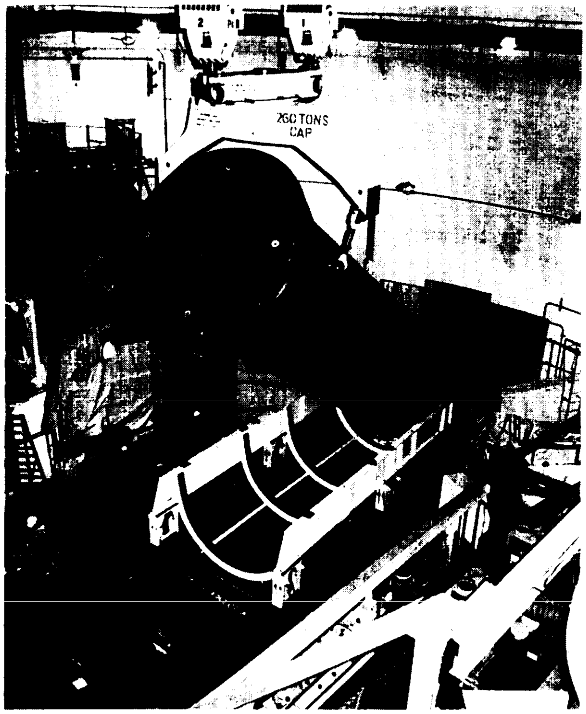
74 U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 1991*, DOE/EIA-0384(91) (Washington, DC: June 1992), p. 237.

75 Institute of Nuclear power Operations, *1992 Performance Indicators for the U.S. Nuclear Utility Industry* (Atlanta, GA: March 1993).

76 W. Liggett and K.C. Wade, "Improvements in Nuclear Power Plant Capacity Factors,' *Electric Power Monthly, DOE/EIA-0226(93/02)* (Washington DC: U.S. Department of Energy, Energy Information Administration February 1993).

77 U.S. Nuclear Regulatory Commission, *Clarification of the TMI Action Plan Requirments*, NUREG-0737, November 1980.

VIRGINIA ELECTRIC POWER CO.



Virginia Power completed its steam generator replacement project at the North Anna plant well under budget, with lower occupational exposures, and in less time than had been anticipated.

10 percent reduction in CFs between 1980 and 1988.[78] Aging degradation of some major plant components such as recirculation pipes in boiling water reactors (BWRs) and SGs in pressurized water reactors (PWRs) have required a variety of maintenance activities including major equipment replacements that also reduced CFs. For example, steam generator replacement outages have generally required several months, although one recent experience at Virginia Power's North Anna plant has reduced that time greatly.[79] In addition, improved water chemistry and better materials used for major component replacements have reduced equipment degradation rates and the resulting outage times.

Finally, EIA noted that management problems in some plants led to poor CFs in the 1980s, a problem mitigated by INPO and EPRI industry-wide efforts to promote the best practices in use. Still, while industry averages have clearly improved, a wide diversity in the range of plant CFs remains (see figure 3-9). For the 96 plants operating during the 3-year period 1989-1991,[80] 27 plants had a CF above 80 percent, while 13 had below 50 percent, with an average of 67 percent.[81] In comparison, one-third of the 61 plants between 1980 and 1982 had CFs below 50 percent, and 13 percent had CFs above 80 percent. Internationally, several countries with large numbers of nuclear plants have had higher average CFs than U.S. plants, while others have had lower CFs. For example, for the year ending June 1992, the average annual CF for Japan's 42 plants was 73 percent compared to 69 percent for the United States, and 63 percent for France's 55 units.[82]

Historical Capital Costs

Over half of the total generation expenses for U.S. nuclear plants is related to recovery of historical capital costs.[83] These historical capital costs include the initial construction costs and later capital additions (i.e., major nonrecurring repairs or retrofits performed to improve plant performance or meet safety requirements). As of 1990, the capital invested in operating nuclear

78 Electric Power Research Institute, *Nuclear Unit Operating Experiment: 1980 through 1988*, 1991.

79 "Virginia Power's North Anna-1 Unit Returned to Service in Record Time," *Electric Utility Week*, Apr. 19, 1993, pp. 6-7.

80 Because year to year fluctuations are routine, a plant's cost and performance in any given year may differ greatly from its long-term record. For this reason, meaningful comparisons between the performance of different plants should consider multiple years.

81 W. Liggett and K.C. Wade, "Improvements in Nuclear Power Plant Capacity Factors," *Electric Power Monthly* (Washington DC: U.S. Department of Energy, Energy Information Administration, February 1993).

82 Nuclear Engineering International, *World Nuclear Industry Handbook 1993*, p. 18.

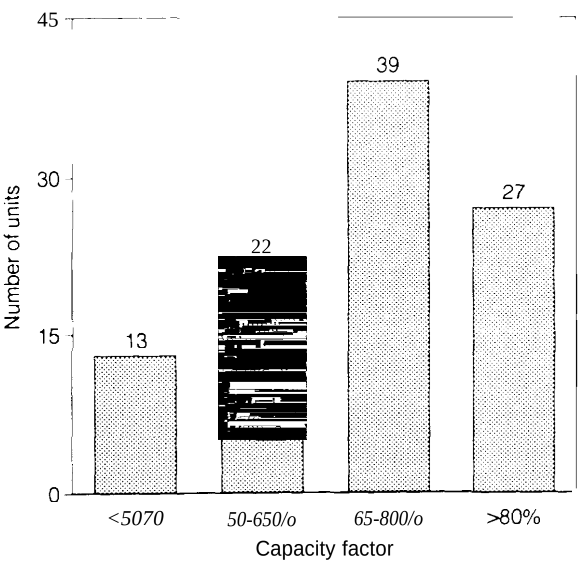
83 U.S. Department of Energy, Energy Information Administration, *Electric Plant Cost and Power Production Expenses 1990*, EIA-0455(90), June 1992, p. 14.

power plants totaled over $150 billion.[84] Utility investments in these historical capital costs are gradually recovered in utility rates over the life of the plant through depreciation and return on investment.

As utility costs increased in the 1980s, many State regulatory commissions scrutinized utility expenditures more closely, especially the often large construction cost escalations for nuclear plants. In some cases, regulators found that plants were unnecessarily expensive or that the generating capacity was not needed and did not allow the utility to recover the full costs from customers. These disallowances may have been justified, but may make utilities reluctant or unable to continue investing in existing plants, especially if high capital costs are involved. For example, a 1992 decision of the Illinois Commerce Commission (ICC) raised the prospect that much of CECO $7.1 billion investment in the Byron 2 and Braidwood-1 and -2 plants were not "used and useful, and thus may not be recovered. As a result, CECO announced substantial cutbacks in capital investment and operating costs and was considering closing nuclear or fossil plants.[85]

Increasing competitive pressures in the electric power industry can also affect a utility's ability to recover capital costs. For example, Public Service of New Mexico (PNM) took a $127 million write-down for its 130-MW (10 percent) share of the Palo Verde unit 3 nuclear power plant in 1992.[86] According to PNM's chairman, the write-down was a move towards "positioning the company for the inevitable open and competitive electric marketplace. '

Figure 3-9-Range of Capacity Factors Over 3-Year Interval, 1989-1991



SOURCE: W. Liggett and K.C. Wade, "Improvements in Nuclear Power Plant Capacity Factors," *Electric Power Monthly* (Washington, DC: U.S. Department of Energy, Energy Information Administration, February 1 993).

New Capital Additions

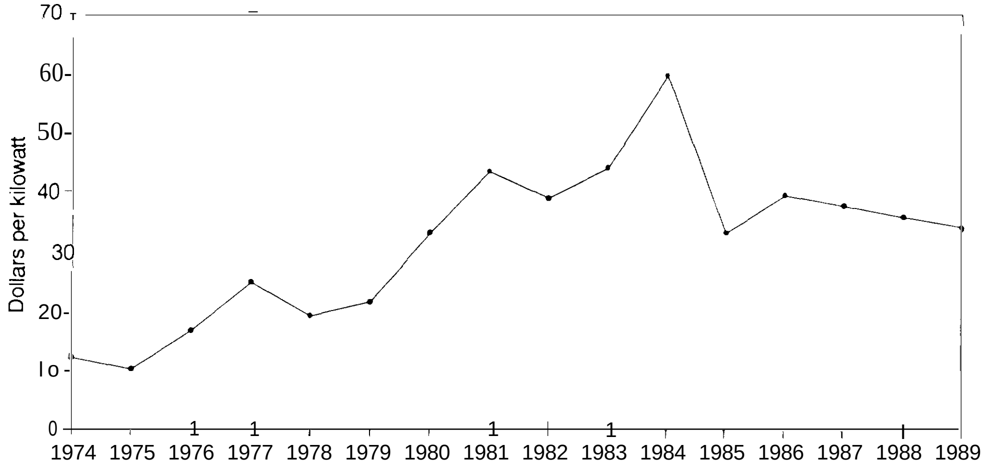
Capital additions are the plant upgrades that include repairs or replacement of major equipment (e.g., replacing SGs) and major plant modifications. Capital additions are generally distinguished from other maintenance costs in that they involve large expenditures on equipment expected to last many years. Capital additions may be needed to meet NRC safety requirements (e.g., seismic and fire control backfits), or utilities may perform them to maintain or improve plant economy, safety, or both. One study of four nuclear plants found that the portion of capital

84 Nominal dollars in year invested. U.S. Department of Energy, Energy Information Administration, *Financial Statistics of Selected Investor Owned Electric Utilities 1990,* DOE/EIA-0437(90)/1, January 1992, p. 40; U.S. Energy Information Administration, *Financial Statistics of Selected Publicly Owned Electric Utilities 1990,* DOE/EIA-0437(90)/2, February 1992, p. 15; and U.S. Department of Agriculture, Rural Electrification Administration, *1988 Statistical Report, Rural Electric Borrowers,* REA Bulletin Number 1-1, 1989.

85 "Commonwealth Announces Cutbacks, Keeps Plant Closings Option Open," *Nucleonics Week,* vol. 33, No. 31, July 30, 1992, pp. 1-2.

86 "PNM Sets $142.5-Million Write-Down Tied to Excess Generating Capacity, " *Electric Utility Week,* Feb. 8, 1993, pp. 9-10.

Figure 3-10—Average Annual Nuclear Power Plant Capital Additions Costs 1974-1989 (1991 dollars per kilowatt of capacity)



SOURCE: Office of Technology Assessment, adapted from U.S. DOE, Energy Information Administration, *An Analysis of Nuclear Power Plant Operating Costs.' A 1991 Update,* DOE/EIA-0547 (Washington, DC: May 1991).

additions costs attributable to NRC safety regulations varied between 34 percent and 65 percent.[87]

The large, one-time costs involved and the potential for long outages may make capital addition decisions de facto plant life decision points. For example, the economic analysis leading to the SONGS-1 early retirement decision was initiated because of the large capital additions request filed by the plant's owner.[88] Similarly, the need to replace the SGs at a cost of up to $200 million weighed heavily in PGE's decision to retire the Trojan nuclear plant, along with the availability of lower cost electricity options.[89]

Historical average capital additions costs have varied greatly, hitting a peak in the mid-1980s (see figure 3-10).[90] Some capital additions have been required to mitigate aging degradation, for example, replacements of recirculation system piping in BWRs and SGs in PWRs. Other capital additions have been unrelated to aging, but resulted instead from deficiencies identified in plant design, such as the TMI and Browns Ferry fire protection backfits.[91] The variety and number of capital additions has been great. For example, table 3-1 shows the variety of major capital additions reported as construction work in progress in 1988. Although any particular capital addition is nonrecurringg, most plants have experienced a series of different capital additions.

Because capital additions typically involve long-lived equipment changes, the costs are not recovered entirely in utility rates in the year they are expended but rather are recovered gradually over several years, as are construction costs. As a result, the expected remaining operating life of a plant can be an important factor in determining

87 SC&A, Inc., "Analysis of the Role of Regulation in the Escalation of Capital Additions Costs for Nuclear Power Plants," ORNL/Sub/88-SC557/1 (Oak Ridge, TN: Oak Ridge National Laboratory, July 1989).

88 California Public Utilities Commission Order 1.89-07-004

89 Portland General Electric Co., *1992 Integrated Resource Plan, Nov. 13,* 1992.

90 Capital additions costs are *not* explicitly reported to the Federal Government as plant-specific costs by utilities in their annual "FERC Form 1" filings, making it difficult to estimate them accurately. U.S. Department of Energy, Energy Information Administration+ An *Analysis of Nuclear Plant Operating Costs: A 1991 Update,* DOE/EIA-0547 *(Washington* DC: May 1991).

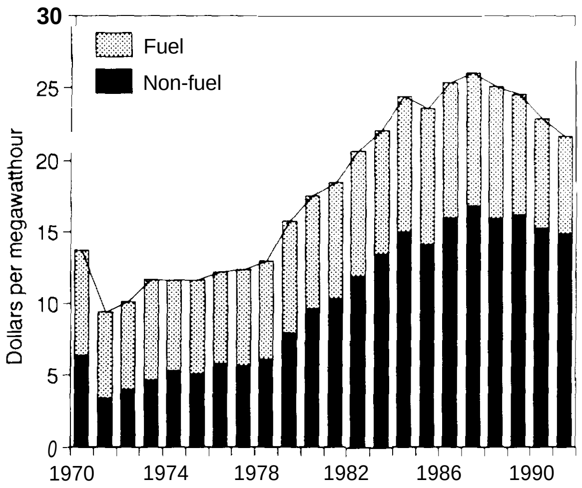
91 10 CFR 50, app. R.

Table 3-I—Capital Additions in Progress in 1988

Category	Number of utilities	Total construction work in progress expenditures ($millions)
Steam generators.	9	109
Low-level waste.	13	92
Fire protection.	14	90
Turbine, generators.	13	79
Water chemistry.	18	51
Control room.	16	43
Core cooling.	14	39
Simulators.	19	38
Spent fuel storage.	14	36
Piping, tubing. ... , ..., .	13	35
Emergency systems.	13	26
Reg Guide 1.97.	4	26
Control rod drive.	8	21
20 other categories.		197

SOURCE: American Nuclear Society, *Supplement to the "Dollar Facts About the U.S. Operating Nuclear Power Plant Market"*, Study No. 9, Section 1, 1990.

Figure 3-11—Nuclear Power Plant Production costs 1970-1991 ($1991)



SOURCE: *Nuclear Engineering International,* September 1992, p. 45; nominal dollars adjusted using Consumer Price Index.

the economic attractiveness of a capital addition. For plants requiring major capital additions but approaching the end of their operating license, resolution of license renewal requirements can therefore play an important role in capital planning.

Fuel, Operation, and Maintenance Costs

Average real fuel and O&M costs per unit of output for nuclear power plants increased markedly between 1974 and 1987 but have since declined by about 20 percent (see figure 3-11).92 Overall, real O&M and fuel costs per unit of production in 1991 were about 2.2 cents/kWh, more than double what they were at their low in 1971. There is general agreement that a return to rapid O&M cost escalation could make existing nuclear plants economically unattractive.[93] Diversity in O&M costs among existing plants is great. For example, the 3-year (1990 to 1992) average O&M cost for the 10 most economic plants was 55 percent below the average industry cost (see figure 3-12).[94]

Much of the historical rise in production costs is attributable to increased plant staffing. Staff-related costs have been estimated at approximately two-thirds of total reported O&M costs.[95] Between 1977 and 1990, staff levels at single unit nuclear plants increased from an average of about 150 employees to over 1,000.[96] Several factors help explain plant staff increases. Part of the increase in average plant staffing resulted from the completion of larger plants. However, staff size at the same plants has increased substantially

92 *Nuclear* Engineering *International,* September 1992, p. 45; nominal dollars adjusted using Consumer Price Index.

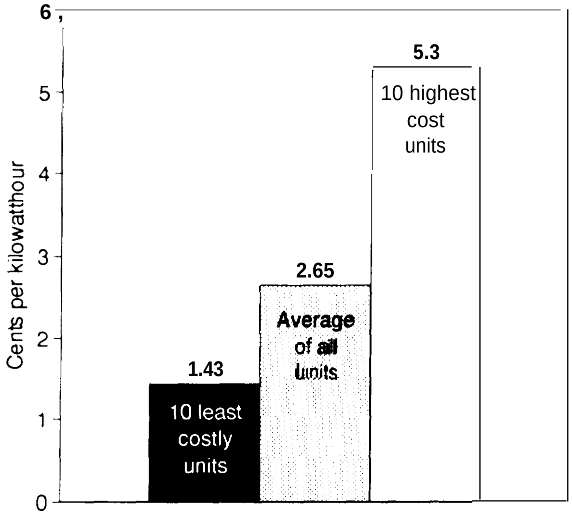
93 See, e.g., Nuclear Management and Resources Council, "Review of Operations and Maintenance Costs in the Nuclear Industry," NUMARC 92-03 (Washington DC: December 1992), pp. 2, 54; and J. G. Hewlett, "The Operating Costs and Longevity of Nuclear Power Plants," *Energy Policy,* July 1992, pp. 608-622.

94 "Wolf Creek Leads As U.S. Utilities Hone Nuclear Economic Performance, " *Nucleonics Week,* vol. *34, No. 25,* June *24, 1993,* pp. 7-10.

95 H.I. Bowers, L.C. Fuller, and M.L.Myers, *Cost Estimating Relationships for Nuclear power Plant Operation and Maintenance, ORIWJI'M-10563 (Oak* Ridge, TN: Oak Ridge National Laboratory, November 1987).

96 "How Many People Does It Take To Run a Nuclear Powerplant?" *Electrical World,* July 1992, pp. 9-13.

Figure 3-12—Diversity in Nuclear Plant Fuel and Operating and Maintenance Costs (3-year average cost, 1990-1992)



SOURCE: "Wolf Creek Leads As U.S.Utilities Hone Nuclear Economic Performance," *Nucleonics Week*, vol. 34, no. 25, June 24, 1993, pp. 7-1o.

over time. For example, the staffing level at the Ginna nuclear plant grew from 59 people in 1970 to approximately 600 in 1990.[97] Other factors include increasing safety and NRC regulatory requirements, economic incentives, and regional conditions, although much of the variation remains unexplained. In contrast to O&M, fuel costs have remained relatively stable in real terms over the past two decades.

Federal reporting requirements do not specifically address several important overhead costs, potentially leading to inaccurate assessments of nuclear plant costs. Overhead costs include annual NRC operating license fees of about $3 million per plant,[98] nuclear liability insurance, plant staff benefits, and other factors, many of which are uniquely or predominantly associated with nuclear plants.[99] These costs are typically reported by utilities in their annual ''FERC Form 1" filings as company-wide costs rather than plant-specific costs and can be difficult to estimate accurately. In total, overhead costs represent a substantial portion of total operating costs, estimated in one analysis at about 30 percent of the reported O&M costs.[100] Although many published reports do not include these costs,[101] they are important to consider in economic decisions about plant life.

FACTORS AFFECTING FUTURE COST AND PERFORMANCE

Several factors affecting nuclear plant cost and performance will likely play important roles in the future. These include:

- plant aging;
- competitive pressures;
- nuclear industry evolution, including new experience, technology, and NRC regulatory changes; and
- radioactive waste disposal.

In an analysis of nuclear production costs, EIA attempted to examine the key factors but found no analytical measure to differentiate the effects of NRC regulatory requirements from the effects of

97 Nuclear Management and Resources Council, "Review of Operations and Maintenance Costs in the Nuclear Industry,' NUMARC 92-03 (Washington DC: December 1992), p. 19.

98 10 CFR 171.15.

99 H.I. Bowers, L.C. Fuller, and M.L.Myers, *Cost Estimating Relationships for Nuclear Power Plant Operation and Maintenance, ORNIJI?M-10563 (Oak* Ridge, TN: Oak Ridge Nationat Laboratory, November 1987).

100 Ibid.

101 See for example, U.S. DOE, Energy Information Administration, *Electric Plant Cost and Power Production Expenses 1990,* DOE/EIA-0455(90), June 1992, table 14, "Average Production Expenses for Nuclear Steam-Electric Plants Owned by Major Investor-Owned Electric Utilities, 1985-1990;'' U.S. DOE, Energy Information Administration, *An Analysis of Nuclear Plant Operating Costs: A 1991 Update,* DOE/EIA-0547, May 1991, p. 5.; and Jim Clarke, "Nuclear O&M Costs Sliding Downward, UDI Says," *The Energy Daily,* vol. *20, No. 127,* July 2, 1992, p. 1.

new technology and information.[102] Further, the analysis lacked information to distinguish between safety-related activities that a utility would have and have not undertaken on its own absent NRC requirements. Similarly, no method was found to distinguish between plant aging (which should increase costs) and utility experience (which could either increase or decrease costs). Some general attributes of the factors affecting cost and performance are noted below.

Effects of Age on Cost and Performance

Plant maintenance to address aging degradation involves a variety of monitoring, evaluation, repair, and replacement activities. Some of these activities involve major capital additions, which may be very costly and could prove to be plant life decision points. Utilities are increasingly developing life-cycle management approaches to coordinate long-term capital planning and mitigate aging degradation for major systems, structures, and components (SSCs).[103] Although expensive, some aging management activities may actually lead to improved economic performance. For example, addressing aging involves improving maintenance programs generally, allowing for preventive or reliability centered maintenance rather than corrective maintenance. The result of applying a preventive maintenance program can be both lower costs and improved availability.[104] Plant experience may improve performance with age as well. This factor, however, is difficult to distinguish from other age-related effects on operational and capital additions costs.

Given the lack of experience with large nuclear plants beyond the middle of their 40 year licensed lives, available evidence to predict accurately the long term effects of aging on economic performance is limited but continues to evolve.[105] As of 1992, only 21 plants were 20 years or older. Those plants are smaller than the younger units, with an average capacity of 616 MW compared to 974 MW.[106] The evolving experience and research is particularly important for those relatively few, but often major, SSCs intended to last the life of a plant (e.g., the reactor pressure vessel, the containment structure).

EIA's analysis of operational costs for existing plants (which, for the study period, had attained an average age of only 13 years) suggests that over the frost third of a plant's assumed design life, the beneficial effects of increasing experience outweighed aging degradation effects, and costs decline with increasing age.[107] However, capital additions costs appeared to increase with age for BWR plants.

The costs of addressing aging degradation have played a role in each of the three early retirement decisions announced in 1992. For the SONGS-1 and Trojan plants, steam generator deterioration were primary aging issues, while the costs to resolve a pressure vessel embrittlement issue contributed to Yankee Rowe's closure.

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102 U.S. Department of Energy, Energy Information Administration, *An Analysis of Nuclear Plant Operating Costs: A 1991 Update*, DOE/EIA-0547 (Washington, DC: May 1991).

103 See, e.g., Grove Engineering, Inc., *Long-Term Capital Planning Considering Nuclear Plant Life-Cycle Management*, EPRI TR-101162 (Palo Alto, CA: Electric Power Research Institute, September 1992); and Stone and Webster Engineering Corp. and Baltimore Gas and Electric Co., *Service (Salt) Water System Life-Cycle Management Evaluation*, EPRI TR-102204 (Palo Alto, CA: Electric Power Research Institute, April 1993).

104 Northern States Power Company, *BWR Pilot Plant Life Extension Study at the Monticello Plant: Interim Phase 2*, EPRI NP-5836M (Palo Alto, CA: Electric Power Research Institute, October 1988).

105 J.G. Hewlett, ''ne operating Costs and Longevity of Nuclear Power Plants,'' *Energy Policy*, July 1992, pp. 608-622.

106 U.S. Department of Energy, *Nuclear Reactors Built, Being Built, or planned: 1991*, DOE/OSTI-8200-R55 (Washington, DC: July 1992), pp. ix-xiv.

107 U.S. Department of Energy, Energy Information Administration, *An Analysis of Nuclear Plant Operating Costs: A 1991 Update*, DOE/EIA-0547 (Washington, DC: May 1991), p. 9.

Competitive and Regulatory Pressures for Improved Cost and Performance

The past years' early retirements and increased attention to the prospect of retirements at other plants have heightened the awareness that poor plant economic performance may have serious consequences. Increasing State regulatory attention to plant life issues as part of IRP efforts and intensifying competition in the electric power market may be powerful motivators for improving nuclear plant costs and performance. One indication of growing industry attention is the development of the Industrywide Initiative noted earlier to improve plant economic performance. The resulting rate of adoption of new cost- and performance-improving measures, and the overall effect on nuclear plant competitiveness, remains to be seen.

Recent efforts by several utilities to reduce nuclear plant staffing, a primary component of plant O&M, provide an example of a growing effort to control costs.[108] Since 1992, several utilities have announced efforts to reduce nuclear-related personnel. For example, Philadelphia Electric Co., operator of four nuclear plants (Peach Bottom units 2 and 3 and Limerick units 1 and 2) announced plans to reduce 635 of 3,400 nuclear operations positions by 1995 for an expected savings of about $35 million to $38 million annually.[109] Similarly, Niagara Mohawk has announced its consideration of cost cutting moves to reduce its 2,000-person nuclear division staff by 20 percent as part of an effort to reduce O&M costs in order to keep operating.[110] The Washington Public Power Supply System also announced plans to reduce its nuclear plant work force of 1,400 by 300.[111]

The industry continues to develop new technologies with the prospect of improving nuclear plant economic performance. Among them are a variety of maintenance approaches including advanced decontamination techniques, reducing worker exposures and thus labor costs (see box 3-A); remote surveillance and robotics that allow monitoring and repair of equipment in previously inaccessible or expensive to work in areas; predictive maintenance practices that allow for better planning of maintenance activities (see ch. 2).

The experience of Virginia Power in replacing the SGs at its North Anna-1 plant is one example of how increased experience may aid in controlling costs. That effort took a far shorter time than planned and typically found in previous SG replacement projects (51 days rather than the planned 150 days); cost substantially less ($130 million rather than the $185 million planned); and resulted in far lower occupational exposures (240 person-rem rather than the 480 predicted).[112] Virginia Power noted that the much better than expected effort resulted from previous experience with Surry 1 and 2, careful advance planning, attention to detail, and support from the project engineer, Bechtel Corp. Not all major projects may be so fortunate, however. For example, steam generator replacement for Millstone unit 2, completed in January 1993 and projected to cost $190 million, took 228 days, 93 more than planned.

108 Utility cost control efforts are not restricted to nuclear plants. Many utilities are reducing non-nuclear staffing, as well, as part of their efforts to meet growing electric industry competition. See, e.g., "Redeployment to Cut PSE&G Jobs by 500—4% of Total-by Early '94," *Electric Utility Week*, Apr. 19, 1993, p. 3; and "PG&E to Freeze Rates Through 1994, Cut Industrial Rates $100-Million," *Electric Utility Week*, Apr. 19, 1993, p. 17.

109 *Electric Utility Week*, Nov. 30, 1992, p. 6; and *Nucleonics Week*, Apr. 22, 1993, p. 4-5.

110 "NiMo's Cost-Cutting Results in 1,400 Lost Jobs," *Electric Utility Week*, Feb. 8, 1993.

111 Harriet King, "Northwest Nuclear Plant's New Strategy," *New York Times*, June 9, 1993, p. D-3.

112 "Virginia Power Sets World Record for Steam Generator Replacement" *Nucleonics Week*, Apr. 15, 1993, pp. 1,11-12.

Box 3-A—Chemical Decontamination

In performing analyses to determine cost-effective occupational radiation exposure reductions, the industry typically uses a value of $10,000 per man-rem.[1] Chemical decontamination techniques represent an increasingly common method to reduce occupational radiation exposures and, thereby, operational costs at existing commercial nuclear power plants.[2] Decontamination-such as manual scrubbing or washing with chemical agents-removes radiologically contaminated materials created in the pressure vessel that have dispersed and settled throughout a steam supply system by the circulation of cooling water.

Experience with chemical decontamination at operating reactors has increased substantially in the last decade, particularly with the development of softer (i.e., less extreme pH ranges), more dilute solutions that cause less wear (e.g., corrosion, pitting, intergranular attack) on plant materials and systems.[3] Early experience with concentrated chemical decontaminants produced high levels of decontamination. However, because of the attendant problems of corrosion damage and waste disposal, concentrated processes will probably not be applied to operating reactors again. A variety of dilute chemical decontaminants can achieve comparable decontamination, but application times vary, which is a more important consideration for operating reactors than retired ones, because of the relatively higher costs for extended down times.

Most applications have been on boiling water reactors (BWRs), particularly as part of pipe maintenance efforts. For BWR applications, 66 to 75 percent of the contaminant radioactivity and corrosion products have been removed in the first chelating step.[4] Although greater levels of decontamination are possible with multiple washings, waste volumes increase with each washing step and, with some recirculating processes, the potential for recontamination increases.

Opportunities exist to make chemical decontamination potentially more effective. Although at least 60 commercial nuclear plant systems at more than 20 reactors have been chemically decontaminated using dilute solutions, no plant has attempted decontamination of the entire reactor coolant system. Consolidated Edison (Con Ed) has proposed demonstrating a full system decontamination (FSD) at its Indian Point unit 2 plant.[5] Con Ed estimates that FSD can reduce radiation fields by a factor of at least five, saving 3,500 man-rems (with an estimated value of $35 million) over the nearly 20 years remaining in the life of the plant.[6]

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1 Consolidated Edison, "Abstract: National Demonstration of Full RCS Chemical Deoontamination," 1992.

2 J.F. Remark, Applied Radiological Control, Inc., *A Review of Plant Decontamination Methods: 1988 Update*, EPRI NP-6169 (Palo Alto, CA: Electric Power Research institute, January 1989), p. 2-9.

3 C.J. Wood and C.N. Spalaris, *Sourcebook for Chemical Decontamination of Nuclear Power Plants*, EPRI *NP-6433* (Palo Alto, CA: Electric Power Research Institute, August 1989), pp. 1-1,1-4,2-1.

4 J.F. Remark, Applied Radiological Control, Inc., *A Review of Plant Decontamination Methods: 1988 Update*, EPRI NP-6169 (Palo Alto, CA: Electric Power Research Institute, January 1989), pp. 2-1 to2-3, 2-8 to 2-9; C.J. Wood and C.N. Spalaris, *Sourcebook for Chemical Decontamination of Nuclear Power Plants*, EPRI NP-6433 (Palo Alto, CA: Electric Power Research Institute, August 1989), p. 2-8.

5 J.B. Mason et al., *Full Reactor Coolant System Chemical Decontamination at Consolidated Edison Indian Point-2 Plant*, Pacific Nuclear Services, November 1991.

6 Consolidated Edison, "Abstract: National Demonstration of Full RCS Chemical Decontamination," 1992.

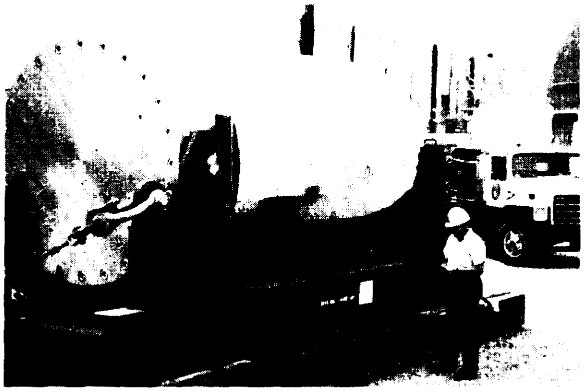
Evolving NRC Activities

Since its creation in 1974, the NRC has often revised regulatory requirements with the goal of assuring adequate safety. These requirements can result in increased operational and capital additions costs. However, to the extent that NRC requirements reflect new experience and information, at least some of these efforts could have been undertaken as part of industry safety efforts even absent NRC's mandates. In response to an NRC request, [113] NUMARC has identi.tied several regulatory requirements that it believes result in increased costs without commensurate benefits to safety. One aspect of the Industrywide Initiative developed by the nuclear industry is to reduce overall costs while maintaining current safety levels as well as to focus on how to change the responses of nuclear utilities to regulatory activities.[114]

Assessing the extent to which future safety regulatory changes, including those related to managing aging, will affect costs at existing nuclear plants is necessarily speculative. As discussed in chapter 2, major aging-related regulatory activities currently include: final implementation of the maintenance and license renewal rules; elevation of fatigue and environmental qualification of electrical equipment to generic safety issues; and resolving how to demonstrate compliance with reactor pressure vessel embrittlement.

Radioactive Waste Disposal

Disposal of spent fuel and low-level waste (LLW) may present increasing future costs. In


VIRGINIA ELECTRIC POWER CO.

One of Virginia Power's dry storage casks for spent fuel.

1991, spent fuel discharges from commercial nuclear power reactors totaled 1,915 metric tons. The total inventory of discharged commercial spent fuel (collected from 1968 to 1991) in the United States is 23,731 metric tons.[115] The total inventory is projected to increase to about 32,000 metric tons in 1995 and 42,000 metric tons by 2000.[116] Water-filled pools in the reactor building are used to cool and store spent fuel for at least 5 years. Under the Nuclear Waste Policy Act of 1982[117] (NWPA), the Federal Government is ultimately responsible for disposal of spent fuel, although progress to date has been limited (see box 3-B).

Inadequate spent fuel storage capacity, together with the lack of progress in DOE's programs, place both direct and indirect costs on existing nuclear power plants. According to data compiled from recent DOE surveys, 28 operating reactors, about 25 percent of all 107 U.S. plants, will have inadequate spent fuel storage capacity

113 "Virginia Power Sets World Record for Steam Generator Replacement" *Nucleonics Week,* Apr. 15, 1993, pp. 1, 11-12.

114 Nuclear Management and Resources Council, "Review of Operations and Maintenance Costs in the Nuclear Industry," NUMARC *92-03,* December 1992, p. 55.

115 U.S. Department of Energy, Energy Information Administration, *Spent Nuclear Fuel Discharges From U.S. Reactors 1991,* SR/CNEAF/93-01 (Washington, DC: February 1993), p. 21. Note: Tonnage figures reflect weight prior to irradiation a proxy measure of the final spent fuel weight,

116 U.S. Department of Energy, Energy Information Administration, *World Nuclear Capacity and Fuel Cycle Requirements 1992,* DOE/EIA-0436(92) (Washington, DC: November 1992), pp. 13-14.

117 Nuclear Waste Policy Act of 1982, Public Law 97-425, Jan. 7, 1983.

Box 3-B–Federal Nuclear Waste Disposal Efforts

The Nuclear Waste Policy Act of 1982[1] (NWPA) established the Office of Civilian Radioactive Waste Management within the U.S. Department of Energy (DOE) and directed the Secretary of Energy to open a repository for spent fuel by January 1998. To pay for this work, NWPA established the Nuclear Waste Fund and set a fee of 0.1 cents per kilowatthour of electricity generated by commercial nuclear plants. As of September 1991, the Fund had collected nearly $8 billion in fees and $2 billion in interest, about $3 billion of which had been spent.[2] However, the original 1998 target date for opening the repository will not be met. Under current plans, DOE expects to complete site characterization work at Yucca Mountain, the only location being investigated, by 2002.[3] DOE estimates that a geologic repository will be ready no sooner than 2010. In a report to Congress and the Secretary of Energy, however, the Nuclear Waste Technical Review Board concluded that even the 2010 schedule appears unrealistic.[4]

As an interim measure, DOE has claimed it would open a monitored retrievable storage (MRS) facility to accept spent fuel by 1998. As with a geologic repository, there are serious doubts about whether this will be available on schedule. In particular, the queue for the first 10 years of spent fuel transfers to an MRS has already been established through a DOE application process. The licensees that will deliver spent fuel, including the quantities and years of disposal, have already been selected.

Undercurrent plans, DOE expects to accept 8,200 metric tons of spent fuel from 60 licensees (including itself) in the first 10 years after an MRS opens.[5] That represents less than 40 percent of the current commercial spent fuel inventory and only about 15 percent of the expected inventory by 2008, the soonest the transfers could be completed under the current schedule, assuming a 1998 start date.[6] Even with a 1998 start date, however, most of the vulnerable 28 units will have to have made other plans or face closure.

In 1992, DOE suggested building the MRS on Federal sites[7] together with development of integrated casks for shipping, storage, and disposal, but the ultimate public, congressional, State, and utility response to the proposal are not yet known. In fact, the recent legal challenges by the State of Idaho to halt shipments of spent fuel from the Fort St. Vrain reactor in Colorado to the Idaho National Engineering Laboratory (INEL) suggest that there can be serious resistance to the use of existing Federal sites for waste storage or disposal.

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1 Nuclear Waste Policy Act of 1982, Public Law 97-425.

2 U.S. Department of Energy, Office of Civilian Radioactive Waste Management, *Annual Report to Congress: Office of Civilian Radioactive Waste Management,* DOE/RW-0335P (Washington, DC: March 1992), pp. 54,65. In simple terms, a 1,000 MWe reactor operating at 80 percent capacity in a given year would be subject to roughly $7 million in Nuclear Waste Fund fees.

3 U.S. Department of Energy, Office of Civilian Radioactive Waste Management, *Progress Report on the Scientific Investigation Program for the Nevada Yucca Mountain Site, No. 6,* DOE/RW-0307P-6 (Washington, DC: September 1992), p. 1-2.

4 Nuclear Waste Technical Review Board, *NWTRB Special Report,* (Arlington, VA: March 1993), p. v.

5 U.S. Department of Energy, Office of Civilian Radioactive Waste Management, *Annual Capacity Rep@* DOE/RW-0331 P (Washington, DC: December 1991), pp. v-vi, 9. A metric ton equals 2,204.6 pounds. Nuclear fuei weights are generally given in metric tons of initial heavy metal (MTIHM), which refers to the original mass of the actinide fuel elements (mostly uranium).

6 U.S. DOE projections of the total inventory of commercial spent fuel by 2008, assuming no new reactors are ordered, is 56,500 metric tons. U.S. Department of Energy, Energy Information Administration, *World Nuclear Capacity and Fuel Cycle Requirements 1992,* DOE/EIA-0436(92) (Washington, DC: November 1992), pp. 13-14.

7 J-SD. Watkins, Secretary, U.S. Department of Energy, letter to J. Bennett Johnston, Chairman, Senate Committee on Energy and Natural Resources, Dec. 17, 1992, attachment, pp. 1-2.

Table 3-2—Plants Projected to Require Additional Spent Fuel Storage Capacity by the Year 2000

Facility (State)	Design capability (MW)	Loss of operability (Year)
Palisades (MI).	755	1993
Prairie Island 1 (MN), ...	507	1995"
Prairie island 2 (MN).	503	1995"
Calvert Cliffs 2 (MD).	825	1996*
Limerick 2 (PA). ... , ...	1,055	1996
Nine Mile Point 1 (NY). . . .	605	1996
Point Beach 1 (WI).	495	1996
Point Beach 2 (WI).	495	1996
Calvert Cliffs 1 (MD).	825	1997"
Peach Bottom 2 (PA).	1,051	1998
Waterford 3 (LA).	1,075	1998
Arkansas Nuclear 1 (AR). .	836	1999
Big Rock Point (MI).	67	1999
Dresden 2 (IL).	772	1999
Duane Arnold (1A).	515	1999
Ginna (NY).	470	1999
North Anna 1 (VA)...	911	1999
North Anna 2 (VA)...	908	1999
Peach Bottom 3 (PA).	1,035	1999
Robinson 2 (SC)..	683	1 999'
Washington Nuclear 2(WA).	1,100	1999
Arkansas Nuclear 2 (AR). .	858	2000
Brunswick 1 (NC).	767	2000
Brunswick 2 (NC)..	754	2000
Dresden 3 (IL).	773	2000
Maine Yankee (ME).	870	2000
Millstone 2 (CT)..	863	2000
Oyster Creek (NJ).	610	2000

NOTE: Units marked with an asterisk (*) have constructed or announced plans to construct ISFSIs to increase their onsite spent fuel storage capacity. The projected closure years shown above, therefore, may no longer apply to some or all of these units.

SOURCE: U.S. Department of Energy, Energy Information Administration, *Spent Nuclear Fuel Discharges from U.S. Reactors 1991,* SR/CNEAF/93-01 (Washington, DC: February 1993), pp. 14-19.

under current plans by the end of the year 2000 (table 3-2).[118] Although measures such as reracking of spent fuel assemblies can extend the capacity of fuel pools somewhat, the number of utilities that will have to construct independent spent fuel storage installations (ISFSIs) in order to continue operating is virtually certain to increase. Dry storage facilities have been or are planned to be constructed at several plants-both those still operating and those undergoing or planning decommissioning.

The direct costs of adding spent fuel storage capacity represent a small but not negligible percentage of other plant operational costs. For example, the Baltimore Gas and Electric Co., operator of the two Calvert Cliffs plants, has constructed an ISFSI for $24 million, with annual operational costs of about $1.5 million. The annualized cost represents less than 2 percent of Calvert Cliffs operating costs.

Some States have been reluctant to allow ISFSI siting, effectively representing a large indirect cost. In the extreme, lack of spent fuel storage threatens several operating plants with premature closure in the next several years. For example, Minnesota's Northern States Power operates the twin Prairie Island plants, which have operating licenses expiring in 2011 and 2013, but current storage capacity is sufficient only through 1995. Out of concern that a requested dry storage facility would become a de facto permanent repository, however, the Minnesota Public Service Commission limited the utility to constructing a facility that added only 7 more years of storage capacity.[119] A state court decision further restricted ISFSI use, ruling that the State legislature must approve any plans to store the fuel more than 8 years.[120] In Wisconsin, similar concerns are at

118 U.S. Department of Energy, Energy Information Administration *Spent Nuclear Fuel Discharges from* U.S. *Reactors 1991,* SR/CNEAF/93-01 (Washington, DC: February 1993), table 4, pp. 14-19.

119 "NSP Gets Reprieve From Minnesota PSC," The Energy Daily, vol. 20, No. 124, June 29, 1992, p. 1. See also *57 Federal Register* 34319 (Aug. 4, 1992).

120 Minnesota law prohibits permanent fuel storage within the State. "Court Decision on Prarie Island Fuels Argument for Moving Waste," *Nucleonics Week,* vol. *34, No. 25,* June *24, 1993,* p. *17.*

issue in the decision to continue operation or retire the Point Beach unit 2 nuclear plant.[121]

At present, the DOE is planning to construct a single national monitored retrievable storage (MRS) facility to store commercial spent fuel until a repository is available. Until that happens, however, an increasing number of de facto MRSs—in the form of dry cask storage installations built at reactor sites—will be necessary, both for many plants to continue operating after 2000 and for decommissioning to occur.

Beyond development of a repository, some treatment methods such as transmutation and reprocessing for spent fuel are under development here and abroad but face major technical, economic, or political obstacles.[122]

LLW disposal costs have increased rapidly in the past and may continue to do so. However, LLW disposal costs during plant operation currently represent a fraction of 1 percent of the operational costs of nuclear plants. Even with the much higher disposal costs anticipated under the interstate compacts, LLW costs would average about 1 percent of operational costs. However, as discussed in chapter 4, there remain unmet challenges in developing LLW disposal facilities.

121 The Point Beach unit 2 decision also involves consideration of a major capital expense, replacement of the plant's steam generators. *Nucleonics Week, vol.* 34, No. 25, June 24, 1993, p. 17.

122 For more information on these and other spent fuel treatment options, see M. Holt and J.E. Mielke, *Civilian* Radioactive *Waste Management: Technical and Policy Issues, 91-867* ENR (Washington DC: Congressional Research Service, Dec. 10, 1991); D. Gibson, "Can Alchemy Solve the Nuclear Waste Problem?' *The Bulletin of Atomic Scientists, vol. 47, No. 6,* July 1991, pp. 12-17; C. Newman, Rockwell International, *International Programs Related to the Transmutation of Transuranics,* EPRI NP-7265 (Palo Alto, CA: Electric Power Research Institute, April 1991); and M. Odell, "Vitrification-World Review," *Nuclear Engineering International,* vol. *37, No. 455,* June 1992, pp. 51-53.