ESTIMATES OF THE COSTS OF DELAYING
OPERATING LICENSES FOR NUCLEAR PLANTS

Prepared by
Division of Power Supply and Reliability
U.S. Department of Energy
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This report is the second in a monthly series of estimates of the costs of delay in the issuance of operating licenses by the Nuclear Regulatory Commission (NRC). This month's report takes account of changes in the estimated length of delays, as well as correction o. other data, that have occurred since the April 9 report was submitted. It provides independently developed Department of Energy (DOE) estimates of the costs of delay, in addition to revised estimates based on data supplied by the utilities.

Unlike the April report, this month's report does not include estimates of the capital carrying costs that are incurred during the delay. These costs are not considered direct losses incurred as a result of the delay.

Summary of Results

The most recently projected dates of issuance of operating licenses for new units would result in a loss of 51 months of reactor operation, based on the utilities' projected dates of completion for 11 units. (This does not include the six additional months of loss of operation projected for the undamaged TMI 1 unit.) Last month's estimate was 95 months for these units. The change is due primarily to recently proposed changes by NRC in its licensing regulations.

The estimated cost of these delays, excluding TMI 1, is $1,199 million, based on data obtained from the utilities in May, or $955 million, based on independent DOE estimates. A direct comparison with last month's report can be made by adding the costs of TMI 1, and by applying the DOE cost estimates to last month's estimates of the length of delay, as follows:

	May 1981 Estimate (Excluding TMI-1)	May 1981 Estimate (Including TMI-1)	April 1981 Estimate (Including TMI-1)	Change
Units Delayed	11	12	13	- 1
Months of Operation Lost	51	57	102	-45
Total Cost of Delays ($MM) Based on				
-- Utility Data	1,199	1,301	2,304	-1003
-- DOE Analyses	955	1,039	1,723	- 684

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The large decrease in estimated cost since last month is primarily attributable to the proposed changes in licensing regulations, which, if implemented, would save $624 million (based on utility data) or $450 million (based on DOE analysis). The remaining portion of the decrease is due to (1) slippage of construction schedules, (2) omission of costs incurred in April 1981 (since past costs are not included), and (3) revisions by utilities of data submitted for the April report.

Length of Delay

The length of the delay--the number of lost months of reactor operation--is estimated in Table 1. For units still under construction, the delay is the interval between the utilities' projected date of completion (column 4) and the NRC's projected date of issuance of operating license (column 3). For units already completed, the delay is based on the period from (but not including) April 1981 through the projected month of issuance of an operating license.

For comparison, last month's estimates of the licensing dates are shown in column 2. The net change of 44 months (excluding TMI 1) in the estimated total length of the delays (column 5) is primarily due to the assumption that changes to its Rules of Practice that the NRC is now considering will be implemented and will result in a savings of two months for each of nine reactors. Revisions in the schedule for Atomic Safety Licensing Board (ASLB) actions for McGuire 1, Susquehanna 1, Summer 1, and Comanche Peak 1 were also assumed to save an additional 11 months. These changes are discussed in NRC's April 30, 1981, report to the House Subcommittee on Energy and Water Development. Susquehanna 2 is not included in this report because a licensing delay is no longer projected. An additional delay of 6 months is projected for the undamaged TMI 1 unit.

Direct Costs of the Delay

The cost of a delay in issuing an operating license after a plant is physically complete is equal to:

- The total costs the entire utility system (or systems, if the unit is jointly owned) would incur to satisfy its customers' energy requirement, based on the delayed licensing schedule, minus

- The total costs of satisfying the same energy requirement if the license had been issued when the plant was complete.

This cost differential is affected only by cost elements that change as a result of the delay--for example, fuel, purchased power, maintenance, and other special expenses. It is not affected by anticipated monthly capital carrying charges or by any other costs that would be incurred with or without the delay.

The estimated direct costs of delay are summarized in Table 2, based on two independent sources:

- One set of estimates (columns 1 through 4) was based on revised data obtained from the owners of the units following an effort by DOE and utility staff to resolve any misunderstandings or inconsistencies that may have been associated with the preliminary data used in the April report; and

- A second set of estimates (columns 5 through 8) was developed independently by DOE staff based on available data on generating resources, pooling arrangements, load projections, capacity factors, and fuel prices. The key assumptions used in this analysis are summarized in Table 3.

Both sets of estimates used the same length-of-delay information (from Table 1, column 5).

Replacement power is the dominant contributor to the cost of licensing delays. The two most important factors affecting replacement power cost are:

- The amount of energy that must be replaced--the number of lost kilowatt-hours of reactor output resulting from the delay--and

- The mix of fuels used to generate the replacement power (oil, gas, coal, nuclear, etc.)

Amount of lost energy: The utilities assumed a capacity factor corresponding to a "mature" nuclear unit--one that has operated for several years. Capacity factors are normally somewhat lower for "immature" units, so the number of kilowatt-hours actually lost during the delay is likely to be less than the number estimated by the utilities. DOE agrees that a "mature" capacity factor is appropriate for estimating the total kilowatt-hour loss, but has chosen, based upon recent past performance (Reference 1), a numerical value (60 percent) that is more conservative than most utilities used.

Fuel Mix: The utilities used a variety of methods to estimate the mix of fuels used to generate replacement power. DOE used the same general approach for all units, but added various judgmental assumptions based on knowledge of certain system-specific operating conditions. (For example, units that would operate as part of an integrated power pool were analyzed on the basis of the entire pool, rather than on the basis of the individual utility.)

DOE used the following analytic approach for estimating the mix of fuels:

- o Estimate the amount of electric energy that must be produced, using recent load projections (Reference 2);
- o Identify the generating resources available to produce this energy, not including the delayed nuclear unit (Reference 3);
- o Remove from consideration (as contributors of replacement power) those resources whose level of operation would be unlikely to change as a result of adding the nuclear units. (These are generally the units with the lowest operating costs or with limitations on their operating hours or fuel availability);
- o Estimate, based on recent history (Reference 4), the amount of energy contributed by each of the remaining classes of units (which generally include coal, oil, and possibly gas-fired units);
- o Estimate the reduction in operation of each class of unit if the nuclear unit is added, taking account of
  - (a) Preferential reduction of units with highest fuel costs;
  - (b) Predominance of units of each fuel type;
  - (c) Physical operating considerations; and
  - (d) Other system-specific factors.
- o Calculate the total costs saved by this reduction in operation, using the fuel costs and heat rates in Table 3;
- o Subtract the fuel costs for the nuclear unit, assumed to be 0.6 cents per kilowatt-hour; and
- o Assume the operating and maintenance (O&M) costs per kilowatt-hour are the same for the nuclear unit and the alternate sources.

An important feature of DOE's approach is that it does not assume that the units with the highest fuel costs (i.e., the oil-fired units) would be th only units to have their operation reduced when a new nuclear unit is placed in service. Although a utility would prefer to reduce the use of high-cost units, there are many operating considerations that require such units to be used. Experience has shown that the introduction of a new baseload unit causes a change in the operating levels of many other units on the system, including units with relatively low operating costs. DOE, in allocating the reduced operation among different classes of generators, used judgmental approximations which, although not exact, were generally consistent with this experience.

DOE's assumptions generally resulted in lower estimates for the monthly cost of replacement power (Table 2, column 5) than those provided by the utilities (column 1). In addition, a few utilities claimed special additional costs associated with the delay (included in column 1). DOE did not attempt to estimate such costs.

TABLE 1

Division of Power Supply and Reliability
U.S. Department of Energy
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DATA ON NUCLEAR UNITS WITH OPERATING LICENSE DELAYS 1/

Unit	Capacity (MW) (1)	Last Month's Projected Date of Issuance of Operating License (April 81) (2)	Current Projected Date of Issuance of Operating License (May 81) (3)	Completion Dates Projected by Company (May 81) (4)	Months of Delay (3) - (4) (5)	Replacement Power Fuel (6)	Replacement Power Source (7)
Comanche Peak 1	1,150	2/83	10/82	12/81	10	Gas	Self-generated
Diablo Canyon 1	1,084	2/82 2/	1/82 2/	1/81	9 6/	Oil	Self-generated
Diablo Canyon 2	1,106	3/82 2/	1/82 2/	10/81	3	Oil	Self-generated
McGuire 1	1,180	12/81	7/81	1/81	3 6/	Coal	Self-generated
Salem 2	1,115	4/81	5/81	4/80	1 6/	Oil-Coal	Purchased
San Onofre 2	1,100	4/82	2/82	6/81	8	Oil	Self-generated
Shoreham 1	854	10/82	8/82	5/82	3	Oil	Self-generated
Summer 1	900	6/82	1/82	8/81	5	Coal-Oil	Self-generated
Susquehanna 1	1,050	11/82	6/82	4/82 5/	2	Oil-Coal 4/	Self-generated
Waterford 3	1,165	1/83	11/82	10/82	1	Oil	Purchased/ Self-generated
Zimmer 1	810	7/82	5/82	11/81	6	Coal-Oil	Self-generated
Total (new units)					51		
TMI 1	776	10/81 3/	10/81 3/		6 6/	Oil-Coal	Purchased

Sources: Utility Companies
Nuclear Regulatory Commission

1/ Covers all units for which construction is expected to be completed at least one month before operating license is issued.
2/ According to company sources, the NRC projected dates do not reflect expediting procedures available to the Commission.
3/ TMI 1 has received an operating license and has been in operation. However, the unit was taken out of service for a routine refueling during February 1979, and was not allowed to return to service following the TMI 2 accident. NRC and the company project the unit will return to service in October 1981.
4/ Delay would reduce utility's coal-fired exports which would replace power in the PJM pool derived from oil and less efficient coal plants.
5/ Since last month's report, the construction of this unit has been delayed by ten months (6/81 to 4/82).
6/ Delays for these completed units prior to 4/81 are not included.

ESTIMATED COSTS OF OPERATING LICENSE DELAYS FOR NUCLEAR UNITS

Unit	Estimated Direct Costs based on Company Data				Estimated Direct Costs Based on Independent DOE Analysis			
	Replacement Power Costs [1/]	Capacity Factor	Replacement Power Costs [2/]	Total Cost [3/]	Replacement Power Costs [8/]	Capacity Factor	Replacement Power Costs	Total Cost [10/]
	-$MM/Month-	-Percent-	--¢/kWh--	--$MM--	-$MM/Month-	-Percent-	--¢/kWh--	--$MM--
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Comanche Peak 1	18.5	70	3.2	185	14.5 [9/]	60	2.9	145
Diablo Canyon 1	31.3 [4/]	65	6.2	282	30.1	60	6.4	271
Diablo Canyon 2	31.3 [4/]	65	6.0	94	30.7	60	6.4	92
McGuire 1	9.4 [6/]	60	1.4	28	5.5	60	1.1	17
Salem 2	23.0	na	4.1	23	14.3	60	3.5	14
San Onofre 2	38.7 [7/]	65	7.0	310	29.6	60	6.1	237
Shoreham 1	30.0	60	8.1	90	20.8 [9/]	60	5.6	62
Summer 1	11.5	65	2.7	58	8.5	60	2.2	43
Susquehanna 1	25.0 [5/]	70	4.7	50	13.5	60	3.5	27
Waterford 3	27.4	75	4.4	27	19.3 [9/]	60	3.8	19
Zimmer 1	8.6	52 [11/]	2.8	32	4.6 [9/]	60	1.3	28
Total (new units)				1199	. . . .			955
TMI 1	17.0	70	4.2	102	14.0	70	3.5	84
Total (including TMI 1)				1301	. . . .			1039

1/ Cost of replacement power minus fuel and operating costs of nuclear units.
2/ Replacement power costs divided by kilowatt-hours replaced. (Column 1 ÷ Column 2 ÷ Unit capacity ÷ 720 hours/month).
3/ Derived by multiplying monthly replacement power costs (column 1) by the total months of delay (Table 1, column 5).
4/ Cost of fuel for 1981 estimated by utility.
5/ Includes fuel-carrying charges.
6/ Includes other abnormal costs of $2.5 million.
7/ Includes other abnormal costs of $2.7 million.
8/ Cost of replacement power minus nuclear fuel costs of 6 mills/kWh.
9/ Most of delay occurs in 1982; therefore, fuel costs are based on 1982 estimates.
10/ Derived by multiplying monthly replacement power costs (column 5) by total months of delay (Table 1, column 5).
11/ The company appears to have used a capacity factor representative of initial operating performance.

na = not available

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KEY ASSUMPTIONS IN DOE ESTIMATES OF COST OF NULCEAR PLANT DELAYS

Unit	Replacement Fuel Mix	Replacement Fuel Price[1/] -$/MMBTUs-	Heat Rate of Replacement Fuel[1/] -BTU/kWh-
Comanche Peak	Gas (100%)	Gas 3.19	10,911
Diablo Canyon 1	Oil (100%)	Oil 6.50	10,678
Diablo Canyon 2	Oil (100%)	Oil 6.50	10,678
McGuire 1	Coal (89.5%) Nuclear (10.5%)	Coal 1.89	Coal 9,488
Salem 2	Coal (50%) Oil (50%)	Coal 1.67 Oil 5.84	Coal 10,083 Oil 11,240
San Onofre 2	Oil (100%)	Oil 6.71	10,035
Shoreham 1	Oil (100%)	Oil 5.94	10,389
Summer 1	Coal (81%) Oil (19%)	Coal 1.71 Oil 7.26	Coal 10,001 Oil 9,944
Susquehanna 1	Coal (50%) Oil (50%)	Coal 1.67 Oil 5.84	Coal 10,083 Oil 11,240
Waterford 3	Oil (100%)	Oil 3.91	11,223
Zimmer 1	Coal (100%)	Coal 1.79	10,567
TMI 1	Coal (50%) Oil (50%)	Coal 1.67 Oil 5.84	Coal 10,083 Oil 11,240

1/ Source: U.S. Department of Energy, Energy Information Administration, FPC Form 423.

REFERENCES

1. The 60% capacity factor assumption was derived from an internal analysis of nuclear plants which were granted operating licenses during the period 1976 through 1979.

2. Load projections were obtained from the U.S. Department of Energy Form ERA-411 and utility submissions to state utility commissions.

3. Generating capacity data were obtained from the U.S. Department of Energy Form ERA-411.

4. Power generation data were obtained from the U.S. Department of Energy FPC Form 4.

5. The nuclear fuel price was obtained from the U.S. Department of Energy's Annual Report to Congress 1980.