

Air Pollution Fees and the Risk of Early Retirement at US Nuclear Power Plants

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ABSTRACT

During the next decade, electricity generation will be deregulated in many US jurisdictions. Nuclear power plants (NPPs) that were ordered and built in a regulated environment will continue to be regulated as nuclear facilities, but the price they receive for their electricity will be set by nonregulated markets. This paper examines the operating expenses and productivity at NPPs with a probabilistic model to identify which plants face the greatest risk of early retirement. Using this identification as a baseline, fees for nitrogen oxides (NOX) are added to the market price in the Eastern US starting in the year 2000. Fees for carbon dioxide (CO₂) are added in the year 2000 and compared with their addition in 2008. Although a few plants remain economically competitive with the addition of NOX fees in 2000, over a dozen plants remain competitive with the early addition of CO₂ fees. However, with the later addition of CO₂ fees, the marginally competitive NPPs are likely to close before these fees are introduced.

Keywords: Nuclear power economics, early retirement, Monte Carlo simulation

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1. Introduction

During 1998, California will be deregulating its electricity generation market, giving consumers the right to choose their power generators. While most of the generating assets of the Californian electric utilities will be sold to independent generators, nuclear power plants (NPPs) will continue to be owned and operated by the utilities that hold the NPPs' operating licenses. Although the Nuclear Regulatory Commission (NRC) is concerned with the transfer of nuclear operating licenses, regulators in some states are pushing for the sale of NPPs, letting the market determine their present value. Facing uncertainty in the form and speed of electricity deregulation, NPP owners are assessing the present value of continued operation of their plants. Some have already decided to retire their plants early and begin decommissioning (see Rothwell 1997).

While states consider deregulating electricity prices, federal authorities are considering increasing restrictions on the emissions of air pollutants. Although regulation of Nitrogen Oxides (NOX) appears probable in the Eastern US between 2002-2004 with a cap and trade program, the form of regulating Carbon Dioxide (CO₂) is now uncertain. If CO₂ fees are implemented to reduce consumption of carbon-based fuels in relationship to 1990 levels, NPPs would become more economically competitive and their continued operation would help reduce CO₂. Unfortunately for NPP owners, the possibility of CO₂ taxes increases the uncertainty in their analysis of continued NPP operation.

Building on two previous papers (Rothwell 1998a and 1998b), here, I describe a probabilistic model of NPP economic viability to identify potential early retirements. I begin by statistically forecasting operating expenses and capacity factors at all US NPPs through the end of their licensed lifetimes. My forecasting technique also yields estimates of the forecasting errors for costs and productivity. With these forecasts and errors I can

compare probability distributions for operating expenses with the projected price of electricity in a deregulated environment, proxied by expected wholesale electricity prices. Using Monte Carlo simulation of these probability distributions, I find approximately 20 nuclear power units at risk of early retirement, assuming national deregulation. Further, I find that one cost of waiting to implement CO2 fees is the increased risk of early retirement for more than half these units.

2. Average Variable Expenses at NPPs

The economics shutdown rule states that a firm will cease production if its average variable cost (AVC, equal to total variable cost divided by output) is greater than price. To determine whether a particular nuclear power unit is likely to cease production because its cost is greater than the market price, this section discusses variable cost; Section 3 discusses output; Section 4 discusses price; and Section 5 discusses the probability that cost is greater than price.

Variable cost includes all costs that vary with additional units of output. But NPPs are continuous production facilities where costs vary little with the production of an additional kilowatt-hour (Kwh). Therefore to distinguish these costs from the traditional definition of AVC, I will refer to them as annual Average Variable Expenses (*AVE*). There are three costs that vary annually: fuel expenses (*FUEL*), operating and maintenance costs (*O&M*), and capital additions (*CAPADD*):

$$TVE_t = FUEL_t + O\&M_t + CAPADD_t, \quad (1)$$

$$AVE_t = (FUEL_t + O\&M_t + CAPADD_t) / Q_t, \text{ and} \quad (2)$$

$$AVE_t = AveFUEL_t + AveO\&M_t + AveCAP_t, \quad (3)$$

where TVE_t are total variable expenses, Q_t is electricity generated in year t , and $AveFUEL_t$, $AveO\&M_t$, and $AveCAP_t$ are annual average fuel, O&M, and capital additions per Kwh (the time subscript will be dropped to simplify notation). While fuel expenses vary with Kwh, O&M and capital additions vary little with additional Kwhs, so quantity must be considered explicitly. This can be done by substituting for Q in equation (2):

$$Q = CF * KWHmax,$$

where (1) CF is the capacity factor and (2) $KWHmax$ is the annual maximum dependable production of kilowatt-hours. Substituting and rearranging,

$$AVE = AveFUEL + (MinO\&M / CF) + (MinCAP / CF), \quad (4)$$

where $MinO\&M (= O\&M / KWHmax)$ is the average O&M cost **at full capacity** (i.e., at a 100% capacity factor) and $MinCAP (= CAPADD / KWHmax)$ is the average capital addition **at full capacity**. This approach (1) explicitly acknowledges the importance of plant productivity (as measured by the capacity factor) in observed average variable expenses and (2) reduces the variance in the measures of O&M and capital additions due to the variance in annual output. With this approach, forecasting AVE requires forecasts of $AveFUEL$, $MinO\&M$, $MinCAP$, and CF .

Before proposing forecasting equations for these variables, consider their history during the last decade. NPP expenses have declined in the US since 1988. See Figure 1. (Note: these expenses are reported by the plant, not by the unit, so plants compose samples in this section; in the next section, nuclear power units compose the samples.) $AveFUEL$ has steadily declined from its highest level in 1984 with declines in uranium prices. $AveO\&M$ and $AveCAP$ declined during the 1990s. These latter declines were due to major increases in capacity factors and minor decreases in costs. Figure 2 presents the cumulative distribution of AVE across plants for 1990 and 1995. In 1990 one-quarter of

the plants had average operating expenses above 3.5 cents (equal to the average price of bulk power sales in the early 1990s, see Hewlett 1992). However in 1995, only one-tenth of the plants were above 3.5 cents.

Previous analyses of NPP costs (including Maidment and Rothwell, 1998) have found significant differences over time for (1) reactor types (Pressurized vs. Boiling Water Reactors, PWR vs. BWR), (2) vintages (commercial operation before, "old," and after 1982, "new"), and (3) whether the plant had one ("single") or more units ("dual"). With these divisions among the plants, there are 8 cohorts. I estimated the following forecasting equations for *AveFUEL*, *MinO&M*, and *MinCAP* for each plant by cohort; see Rothwell (1997a):

$$AveFUEL_{it} = a_{1j} + b_{1j} (1 / TIME_t) + e_{1it} \quad (5a)$$

$$MinO\&M_{it} = a_{2j} + b_{2j} (1 / TIME_t) + e_{2it} \quad (5b)$$

$$MinCAP_{it} = a_{3j} + b_{3j} (1 / TIME_t) + e_{3it} , \quad (5c)$$

where t indexes the year of the observation, i indexes the plant, j indexes the cohort, a and b are parameters to be estimated, $TIME$ is years since 1986, and e is the error term.

Under appropriate assumptions (see Rothwell 1998a), these simple forecasting equations yield straightforward estimates of the forecasting error:

$$FError(AveFUEL_{it}) = Var(A_{1j}) + Var(E_{1it}) \quad (6a)$$

$$FError(MinO\&M_{it}) = Var(A_{2j}) + Var(E_{2it}) \quad (6b)$$

$$FError(MinCAP_{it}) = Var(A_{3j}) + Var(E_{3it}) , \quad (6c)$$

where $FError$ is the Forecast Error, Var is the Variance, A is the estimated value of a , and E is the residual. With data from 1987 through 1996, I use plant-specific parameters estimated in cohort-defined samples to forecast individual plant expenses. Figure 3 presents the cumulative distribution of plant-specific forecasts of *AVE* in the year 2000

with a 90% error band, i.e., plus ("HIGH") and minus ("LOW") 1.67 times the standard deviation of the forecast error, *assuming* a 75% capacity factor. An examination of these forecasts (in Rothwell 1998a) shows that old, single-unit plants have the highest probability of experiencing expenses above 3.5 cents. However, these results depend on the assumed 75% capacity factor. The next section discusses whether this is an appropriate assumption.

3. Forecasting Nuclear Power Plant Performance

During the 1980s and 1990s, productivity at US nuclear power units improved dramatically. Average annual capacity factors (CFs) increased from 58% in 1980 to 62% in 1985 to 68% in 1990 to 79% in 1995. See Rothwell (1998b). Figure 4 presents annual nuclear power unit CFs from 1975 to 1995 with plus and minus one standard deviation (SDev). The cumulative distribution of unit-specific capacity factors for 1990 and 1995 are shown in Figure 5: while only one-third (35%) of the nuclear power units experienced CFs above 75% in 1990, three-quarters (77%) of the units had CFs above 75% in 1995.

Because of the differences among average CFs for Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs) from different manufacturers and NPPs of different sizes, I follow Thomas (1990) and consider 8 cohorts: (1) Westinghouse PWRs smaller than 700 Mw, all came into commercial operation before 1982; (2) Westinghouse PWRs between 700 and 1000 Mw; (3) Westinghouse PWRs larger than 1000 Mw; (4) Babcock & Wilcox PWRs, all between 700 and 1000 Mw; (5) Combustion Engineering PWRs, all are larger than 700 Mw; (6) General Electric BWRs smaller than 700 Mw, all

came into commercial operation before 1982; (7) General Electric BWRs between 700 and 1000 Mw; and (8) General Electric BWRs larger than 1000 Mw.

Rothwell (1998b) estimated forecasting equations and forecasting errors for unit-specific CFs by cohort:

$$CF_{it} = a_{it} + b_{it} (1 / TIME_i) + e_{it}, \quad (7a)$$

$$FError(CF_{it}) = Var(A_{it}) + Var(E_{it}) \quad (7b)$$

where TIME is years since 1982, when the *Three Mile Island Licensing Action Requirements* were published. Using data from 1983 through 1995, Figure 6 presents the cumulative distribution of the unit-specific forecasts for CF in the year 2000 with a 90% error band (plus, "HIGH," and minus, "LOW," 1.67 times the standard deviation of the forecast error). Rothwell (1998b) found that while some single-unit plants have been chronically unproductive (i.e., had capacity factors below 75% throughout the 1990s), many older, multiple-unit plants have also been chronically unproductive. Because expensive units (those with $AVE > 3.5$ cents) have not necessarily been unproductive (and vice versa), to determine economic viability, forecasts of expenses and productivity must be combined and compared with anticipated prices.

4. Deregulated Electricity Prices

Deregulation of electricity markets in the US is presently focused on introducing competition into the generating sector. For example, in California an independent power pool operator is now coordinating buyers and sellers of electric power at market prices. Although it is not known when other jurisdictions will introduce competition into electricity generation, in this analysis I assume that if NPP owners can purchase power at a competitive price below the cost of producing power at their NPP, and they cannot

charge customers this difference, then their NPP is at risk of early retirement. The closure decision will rest on other factors, such as whether capital costs can be recovered even though the plant is not "used and useful." Therefore, this analysis does not predict whether individual nuclear power units will retire, but suggests how the probability of early retirement changes under different regulatory scenarios. Of course, these decisions depend on expectations regarding competitive electric power prices.

Forecasting electricity prices under deregulation is inherently difficult. I rely on forecasts underlying *AEO 1998* (US DOE/EIA, 1997b) for competitive market prices, see US DOE/EIA (1997a), which provides forecasts for each year from 1998 through 2000 for 13 regions in the U.S. See Table 1. (These are National Energy Modeling System regions, which are either National Electricity Reliability Council, NERC, regions or subdivisions of these regions.) I assume that prices converge between regions under electricity deregulation: (1) from 2000-2005 spot prices converge within 5 regions of the country (North East=regions 3+6A+6B, South East=regions 7A+7B, North Central=regions 1+4+5, South Central=regions 2+8, and WSCC=regions 9A+9B+9C) and (2) from 2005-2010 prices converge to a national minimum spot price of 24.9 mills (1995\$) or about 2.5 cents. See Table 1. I assume that this national price holds until 2020. This convergence occurs through two mechanisms: (1) building transmission capacity between regions of unequal prices and (2) building low-cost generation in high-cost regions.

NOX and CO₂ fees can be added to these regional prices. (These values were supplied by Sue Gander of the Center for Clean Air Policy.) The NOX fee was calculated at 1.29 mills/Kwh (1995\$) assuming a system, annual average of \$2,083/ton (equal to 5/12ths, i.e., 5 out of 12 months, of \$5,000/ton) for NOX in states covered by

EPA's Ozone Transport Rulemaking. A carbon fee of \$15/ton is equivalent to 6.1 mills/Kwh, assuming 800 pounds of CO₂ per average US Mwh (with trading among Annex B countries). The NOX fee is added to the regional price in appropriate regions in the year 2000. The CO₂ fee is added to the regional price (plus the NOX fee, where appropriate) in 2000 and in 2008. (See Table 5.)

5. Identifying Uncompetitive Nuclear Power Plants

Table 2 presents Monte Carlo simulations (with Latin Hypercube sampling using the program @RISK, www.palisade.com) of the number of nuclear power units that are economically competitive at projected prices. In each simulation from 2000 to 2020, 100 selections are made from the probability distributions of *AveFUEL*, *MinO&M*, *MinCAP* and *CF*. Table 2 compares nuclear power units and output under a "Regulation" case of continued rate-of-return regulation (similar to the *AEO 1998* "Reference") with a national "Deregulation" case. Four results are given for the number of units and their output (in terawatt-hours, Twhs): "Fore" is the deterministic forecast value at the expected means of the probability distributions of the cost and productivity variables; (2) "Mean" is the mean number of competitive ($AVE < \text{Price}$) nuclear power units or their output in the simulated distribution of *AVE*; (3) "SDev" is the Standard Deviation of this simulated distribution; and (4) "Max" is the maximum realized value in the simulated distribution.

In the year 2000, using a deterministic value for *AVE* and projected prices, there could be as many as 18 (105 - 87) nuclear power units at risk of early retirement assuming deregulation of generation in all relevant jurisdictions. This can be compared to the mean of the simulated distribution where 21 units are at risk of early retirement. The number of units and output in the deterministic forecast is always greater than the mean of the simulated distribution, indicating bias in the deterministic model and asymmetry in the simulated probability distribution of *AVE*.

The maximum number of units or output represents an "optimistic" scenario. For example, in at least one percent of the simulations in the year 2000, 91 units were competitive, i.e., with national deregulation by 2000, optimistically, there are at least 14 units that would be uncompetitive if cost and productivity variables were similar to their values during the first half of the 1990s.

Tables 3 and 4 present regional results for the means of the simulated distributions. In Table 3 the first line gives the number of units assumed to be operating in the year 2000 in the AEO "Reference." In Table 4 the first line gives the projected output in the year 2000 using the forecasting version of equation (7a). While Region 1 has the highest percentage of plants at risk of early retirement (due primarily to the low price of power in that region) and Regions 2 and 9 have no plants at immediate risk of early retirement, these results do not imply that specific units will close. Because of the statistical characterization of these units, i.e., I am using forecasts based on historical data rather than projections based on case studies of particular plants, the standard errors on the probability of closure are high for individual units. Only at the national level can one make reasonable conclusions regarding the aggregate number of early retirements.

Tables 5, 6, and 7 compare 5 cases: (1) "Regulation" assumes there is no change in regulation, so nuclear units operate until the end of their operating licenses; (2) "Deregulation" assumes that NPPs must compete in power pools at market prices; (3) "NOX in 2000" is the Deregulation case where fees on NOX emissions, equivalent to an addition of 1.29 mills (1995\$), are added to the competitive market price beginning in the year 2000; (4) "Fees in 2000" is the same as "NOX in 2000" with CO2 fees (carbon taxes) equivalent to a market equilibrium addition of 6.1 mills (1995\$) to the competitive market price in 2000; and (5) "Fees in 2008" is the same as "Fees in 2000," but carbon taxes are not implemented until 2008. The results in Tables 5-7 are listed relative to the Regulation case.

Table 5 presents results at the expected means of *AveFUEL*, *AveO&M*, *AveCAP*, and *CF*, i.e., there is no simulation of the distributions of these variables. Table 6 presents the means of the simulated distributions. Table 7 presents maximums of the simulated distributions. The results of Table 5-7 are also presented in Figures 7-9 where the number of nuclear power units are shown by year for the 5 cases, and in Figures 10-12 where the output in Twhs are shown for the 5 cases.

Considering these tables, I first discuss the number of units at risk in the year 2000, then discuss changes in these numbers from 2000 to 2020. Under the Regulation case, no units are at risk of retirement before 2006. This corresponds to an approximate 40-year operating lifetime beginning in 1966. (Units that were retired before January 1, 1998, were excluded; as were Browns Ferry 1, which did not operate from April 1986 through the end of 1997, and Browns Ferry 3, which did not operate from April 1986 through November 1995.) In Table 5 at the expected values of the cost and productivity variables, 18 units would be at risk of retirement with a nationally deregulated electricity generation industry in the year 2000. (This corresponds to the column labeled "Fore" in Table 2.) When the probability distributions of these means and forecast errors are simulated, the expected number of units at risk increases to 21 (Table 6, or the column labeled "Mean" in Table 2). On the other hand, in Table 7 in one of the 100 simulations, only 14 units were found to be at risk. (See Table 2, columns labeled "Max.")

Comparing these "maximums" across cases, with the addition of a NOX fee in the year 2000, *only one more unit* becomes competitive (i.e., a rise from $105-14=91$ to $105-13=92$). With the addition of both a NOX and CO2 fee in 2000, *10 more units* are competitive (*only 4 plants* are at risk of early retirement in 2000 with both fees).

Between 2000 and 2008, operating licenses at 6 units will expire. However, with national deregulation (a likely possibility by 2008) and no effluent fees, the minimum number of units at risk jumps from 14 to 23 (see the middle column of Table 7) due primarily to decreases in competitive prices in particular regions as prices decline to 2.5

cents/Kwh in 2010. Because of the randomness in the maximum number of competitive units (or, equivalently, the minimum number of uncompetitive units), there could be fewer competitive units in 2008 under the "Fees in 2008" case (-20) than with the "NOX in 2000" case (-19). This points to the lack of dominance of the "NOX in 2000" case over the "Deregulation" case. (See Figure 9.)

When CO₂ fees are implemented early, there are fewer plants at risk of closure before 2008. In fact, those units at risk of retirement before 2008 retire by 2020, so that the maximum number of competitive units is indistinguishable from the Regulation case in 2020. (See the last column of Table 7 for both units and Twhs.) Throughout this analysis, there is an assumption that capacity factors continue to increase slightly with time. The Twhs values in Tables 5-7 facilitate the calculation of extra tons of NOX and CO₂ under the different regulatory cases given regional mixes in electricity generation, but these calculations are left for future research.

The final set of tables (Tables 8 and 9) compare the maximum number of competitive units and output with the implementation of CO₂ fees in the year 2000 with implementation of CO₂ fees in the year 2008. These values represent regional "costs of waiting" to implement CO₂ fees. Although this cost could only be a few units in each region (i.e., out of 100 simulations, there are few differences between the two cases) at the national level, by the year 2008, as many as 14 units could retire before CO₂ fees are implemented. This will imply an increased burden on attempts to achieve internationally agreed upon carbon reductions.

6. Discussion

During the next decade, electricity generation will be deregulated in the US. Deregulation involves (1) restructuring of electricity generator ownership and (2) the creation of electricity markets where the cost of marginal producer will determine the competitive price. During the institutional transition from the current system to a

deregulated one, nuclear power plant operators will face increasing uncertainty regarding the price they receive for their product. Because of the capital intensity of the nuclear power industry, the real and financial costs of continuing to operate and maintain NPPs will rise in a risky environment unless steps are taken to reduce expenses, particularly those for labor, which account for a large percentage of O&M. If costs are not reduced, there are approximately two dozen units at risk of early retirement before 2006, when nuclear power unit operating licenses begin to expire. However, with early implementation of air pollution fees, only half these units appear to be at risk of early retirement.

Between 2006 and 2016, 50 nuclear power operating licenses will expire, unless life extension programs are implemented. However, even if life extension regulations are finalized before 2013 (11 licenses expire in 2013 and 12 licenses expire in 2014), many units at risk of early retirement will actually retire before these regulations are promulgated. Until electricity deregulation, environmental regulation, and nuclear power plant regulations are solidified, uncertainty facing owners of nuclear power plants will encourage earlier retirements than in a more certain operating environment.

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Table 1: Regional Price Paths by Year (in 1995 mills)

Region	1	2	3	4	5	6A	6B	7A	7B	8	9A	9B	9C	10
1998	27	27	35	28	28	35	36	38	30	31	34	30	41	31
1999	27	27	35	28	29	35	38	38	30	32	38	31	42	32
2000	25	28	33	26	28	36	38	37	29	33	36	31	41	31
2001	25	28	33	26	27	35	37	35	29	32	35	31	39	32
2002	25	28	33	25	27	35	36	34	29	31	34	31	37	31
2003	25	28	33	25	26	34	35	32	29	30	33	31	35	31
2004	25	28	33	25	26	34	34	31	29	29	32	31	33	30
2005	25	28	33	25	25	33	33	29	29	28	31	31	31	29
2006	25	27	31	25	25	31	31	29	29	27	30	30	30	28
2007	25	27	30	25	25	30	30	28	28	27	28	28	28	28
2008	25	26	28	25	25	28	28	27	27	26	27	27	27	27
2009	25	26	27	25	25	27	27	26	26	26	26	26	26	26
2010	25	25	25	25	25	25	25	25	25	25	25	25	25	25

- Region 1: ECAR=East Central Area Reliability Coordination Agreement Region
 Region 2: ERCOT=Electric Reliability Council of Texas
 Region 3: MAAC=Mid-Atlantic Area Council
 Region 4: MAIN=Mid-America Interconnected Network
 Region 5: MAPP=Mid-Continent Area Power Pool
 Region 6A: New York Power Pool; Northeast Power Coordinating Council (NPCC)
 Region 6B: New England Power Pool of the NPCC
 Region 7A: Florida; Southeastern Electric Reliability Council (SERC)
 Region 7B: Remainder of the SERC
 Region 8: SWPP=Southwest Power Pool
 Region 9A: Northwest Power Pool; Western Systems Coordinating Council (WSCC)
 Region 9B: Rocky Mountain and Arizona-New Mexico Power Areas of the WSCC
 Region 9C: California and Southern Nevada Power Area of the WSCC
 Region 10: Average of all regions (i.e., a "National" average)

Table 2: Comparing Status Quo Regulation with National Deregulation, 2000-2020

Year	Regulation		Deregulation Units				Deregulation Twhs			
	Units	Twhs	Fore	Mean	SDev	Max	Fore	Mean	SDev	Max
2000	105	636	87	84	2.6	91	545	532	15	562
2001	105	634	86	83	3.0	90	542	530	19	580
2002	105	635	86	83	3.2	90	542	527	19	572
2003	105	635	86	82	3.1	89	542	524	18	574
2004	105	637	86	81	3.2	89	543	521	19	568
2005	105	636	85	80	3.0	86	538	513	19	548
2006	103	625	80	77	3.5	87	512	494	22	550
2007	100	612	76	72	3.1	80	491	470	19	517
2008	99	607	71	69	2.9	76	461	450	19	495
2009	97	597	68	64	3.4	73	445	424	22	471
2010	93	581	62	59	3.0	68	416	393	20	445
2011	92	577	62	59	3.1	65	416	394	22	440
2012	87	557	61	57	3.2	66	411	384	23	459
2013	76	502	53	49	3.0	56	370	342	21	394
2014	64	438	47	42	2.4	48	336	307	18	353
2015	62	426	46	41	2.7	47	330	298	20	343
2016	56	394	44	39	2.1	42	318	284	16	315
2017	53	375	42	37	2.0	42	306	275	15	313
2018	50	358	40	35	2.2	40	295	264	17	307
2019	50	358	40	35	2.1	40	295	264	17	302
2020	47	341	38	34	2.0	39	281	253	16	294

Units = Nuclear Power Units
 Twhs = Terawatt-hours of Electricity
 Fore = Value at Deterministic Forecast
 Mean = Mean of Random Distribution
 SDev = Standard Deviation of Random Distribution
 Max = Maximum Value in Random Distribution

**Table 5: Differences in Deterministic Forecasts
under Effluent Fee Scenarios, 2000-2020**

Year	Regulation		Deregulation		NOX in 2000		Fees in 2008		Fees in 2000	
	Units	Twhs	Units	Twhs	Units	Twhs	Units	Twhs	Units	Twhs
2000	105	636	-18	-90	-14	-68			-6	-31
2001	105	634	-19	-93	-14	-66			-6	-30
2002	105	635	-19	-93	-15	-70			-7	-33
2003	105	635	-19	-93	-15	-70			-7	-33
2004	105	637	-19	-95	-15	-72			-7	-35
2005	105	636	-20	-98	-16	-75			-7	-33
2006	103	625	-23	-113	-17	-79			-7	-33
2007	100	612	-24	-121	-20	-101			-8	-37
2008	99	607	-28	-146	-22	-115	-20	-103	-8	-39
2009	97	597	-29	-153	-24	-126	-19	-97	-8	-39
2010	93	581	-31	-165	-28	-150	-18	-93	-9	-43
2011	92	577	-30	-161	-27	-146	-17	-89	-9	-43
2012	87	557	-26	-146	-24	-135	-15	-82	-8	-40
2013	76	502	-23	-132	-21	-122	-13	-74	-6	-32
2014	64	438	-17	-101	-16	-96	-11	-63	-5	-29
2015	62	426	-16	-96	-15	-90	-11	-63	-5	-29
2016	56	394	-12	-76	-11	-70	-7	-43	-5	-30
2017	53	375	-11	-69	-10	-63	-6	-36	-4	-23
2018	50	358	-10	-64	-9	-58	-6	-36	-4	-23
2019	50	358	-10	-64	-9	-58	-6	-36	-4	-23
2020	47	341	-9	-59	-8	-53	-5	-31	-3	-19

**Table 6: Differences in Means of Random Distributions
under Effluent Fee Scenarios, 2000-2020**

Year	Regulation		Deregulation		NOX in 2000		Fees in 2008		Fees in 2000	
	Units	Twhs	Units	Twhs	Units	Twhs	Units	Twhs	Units	Twhs
2000	105	636	-21	-103	-19	-90			-9	-40
2001	105	634	-22	-104	-19	-90			-9	-39
2002	105	635	-22	-108	-19	-92			-9	-40
2003	105	635	-23	-111	-21	-97			-9	-40
2004	105	637	-24	-116	-21	-102			-9	-43
2005	105	636	-25	-123	-22	-106			-10	-45
2006	103	625	-26	-131	-24	-117			-10	-47
2007	100	612	-28	-142	-24	-123			-11	-49
2008	99	607	-30	-157	-27	-141	-22	-112	-12	-56
2009	97	597	-33	-174	-29	-152	-22	-110	-12	-55
2010	93	581	-29	-157	-31	-166	-21	-110	-13	-65
2011	92	577	-33	-184	-30	-162	-20	-106	-12	-61
2012	87	557	-30	-172	-27	-153	-18	-97	-11	-59
2013	76	502	-27	-160	-24	-142	-16	-88	-10	-51
2014	64	438	-22	-131	-19	-116	-12	-71	-7	-41
2015	62	426	-21	-128	-18	-112	-12	-69	-7	-39
2016	56	394	-17	-110	-15	-98	-8	-50	-6	-33
2017	53	375	-16	-100	-14	-88	-7	-42	-5	-29
2018	50	358	-15	-94	-13	-81	-7	-41	-5	-27
2019	50	358	-15	-95	-13	-83	-7	-41	-5	-27
2020	47	341	-13	-87	-12	-76	-6	-37	-2	-9

**Table 7: Differences in Maximums of Random Distributions
under Effluent Fee Scenarios, 2000-2020**

Year	Regulation		Deregulation		NOX in 2000		Fees in 2008		Fees in 2000	
	Units	Twhs	Units	Twhs	Units	Twhs	Units	Twhs	Units	Twhs
2000	105	636	-14	-73	-13	-53			-4	-15
2001	105	634	-15	-54	-13	-50			-4	-13
2002	105	635	-15	-63	-15	-59			-5	-8
2003	105	635	-16	-61	-14	-53			-5	-15
2004	105	637	-16	-69	-14	-56			-4	-6
2005	105	636	-19	-88	-11	-54			-4	-12
2006	103	625	-16	-75	-18	-77			-5	-14
2007	100	612	-20	-95	-18	-86			-5	-14
2008	99	607	-23	-112	-19	-79	-20	-91	-7	-20
2009	97	597	-24	-126	-21	-103	-19	-87	-7	-5
2010	93	581	-20	-110	-24	-125	-18	-81	-7	-30
2011	92	577	-27	-137	-20	-109	-17	-76	-6	-21
2012	87	557	-21	-98	-20	-102	-15	-71	-6	-17
2013	76	502	-20	-108	-18	-95	-13	-66	-5	-14
2014	64	438	-16	-85	-13	-72	-11	-49	-4	-6
2015	62	426	-15	-83	-14	-78	-11	-48	-3	-1
2016	56	394	-14	-79	-10	-58	-7	-34	-2	-4
2017	53	375	-11	-61	-9	-52	-6	-23	-2	1
2018	50	358	-10	-51	-6	-34	-6	-23	-2	2
2019	50	358	-10	-56	-7	-40	-6	-23	-2	1
2020	47	341	-8	-47	-8	-45	-5	-15	1	19

**Table 3: Unit Means of Random Distributions under National Deregulation
by Region, 2000-2020**

Region	1	2	3	4	5	6	7	8	9	10
Reg in 2000	8	4	13	17	6	12	31	6	8	105
2000	2	4	10	13	4	10	28	5	8	84
2001	2	4	10	13	4	10	28	5	8	83
2002	2	4	10	13	4	10	28	5	8	83
2003	2	4	10	13	4	9	28	5	8	82
2004	2	4	10	13	4	9	27	5	8	81
2005	2	4	10	12	3	9	27	4	7	80
2006	2	4	9	12	3	8	27	4	7	77
2007	2	3	9	12	3	7	25	4	6	72
2008	2	3	8	12	3	6	24	4	6	69
2009	2	3	7	12	3	5	23	4	5	64
2010	2	3	7	12	3	5	23	4	5	64
2011	2	3	7	11	3	4	22	4	4	59
2012	2	3	7	10	3	3	21	4	4	57
2013	2	3	7	7	2	3	18	4	4	49
2014	1	3	5	7	0	3	16	3	4	42
2015	1	3	5	7	0	2	16	3	4	41
2016	1	3	4	7	0	2	15	3	4	39
2017	0	3	4	7	0	2	14	3	4	37
2018	0	3	4	7	0	2	13	3	4	35
2019	0	3	4	7	0	2	13	3	4	35
2020	0	3	4	7	0	2	11	3	4	34

**Table 4: Twh Means of Random Distributions under National Deregulation
by Region, 2000-2020**

Region	1	2	3	4	5	6	7	8	9	10
Reg in 2000	47	28	85	96	23	65	191	40	60	636
2000	15	26	72	76	16	57	176	35	59	532
2001	14	26	72	77	16	56	176	35	59	530
2002	14	26	72	76	15	55	176	34	59	527
2003	14	26	72	77	15	53	175	34	58	524
2004	15	26	72	76	15	53	174	33	57	521
2005	14	26	73	75	14	51	172	32	55	513
2006	15	25	65	74	14	48	171	31	52	494
2007	14	24	61	75	14	42	161	31	48	470
2008	14	24	55	75	14	37	156	30	45	450
2009	11	23	51	75	14	31	152	28	39	424
2010	11	23	51	75	14	31	152	28	39	424
2011	11	23	48	71	11	25	145	27	34	394
2012	11	23	48	67	11	23	140	27	35	384
2013	11	23	48	51	7	21	124	28	31	342
2014	5	23	40	51	0	21	112	25	30	307
2015	6	23	39	51	0	16	111	25	29	298
2016	4	23	33	51	0	15	103	25	30	284
2017	0	23	34	51	0	15	97	24	31	275
2018	0	22	34	51	0	15	90	21	30	264
2019	1	23	34	51	0	15	90	21	30	264
2020	0	23	34	51	0	16	80	20	30	253

**Table 8: Difference between Mean Units in Random Distribution
for each Region assuming NOX and CO2 from 2000 and from 2008**

Region	1	2	3	4	5	6	7	8	9	10
2000	2	0	1	2	1	1	2	0	0	10
2001	2	0	1	2	1	1	2	0	0	10
2002	2	0	1	2	1	1	2	0	0	11
2003	2	0	1	3	1	2	2	0	0	11
2004	2	0	1	2	1	2	2	0	0	12
2005	2	0	1	2	1	2	2	1	1	12
2006	2	0	1	2	1	2	3	1	1	13
2007	2	1	1	2	1	3	3	1	1	14
2008	2	0	1	2	0	2	2	0	1	10
2009	2	0	1	2	1	2	2	0	1	10
2010	2	0	1	2	1	1	2	0	1	8
2011	2	0	1	2	0	1	2	0	1	8
2012	2	0	1	1	0	0	2	0	1	7
2013	2	0	1	1	0	0	2	0	1	6
2014	2	0	1	1	0	0	1	0	1	5
2015	2	0	1	1	0	0	1	0	1	5
2016	1	0	0	1	0	0	0	0	1	2
2017	0	0	0	1	0	0	0	0	1	2
2018	0	0	0	1	0	0	0	0	1	2
2019	0	0	0	1	0	0	0	0	1	2
2020	0	0	0	1	0	0	2	0	1	4

**Table 9: Difference between Mean Twhs in Random Distribution
for each Region assuming NOX and CO2 from 2000 and from 2008**

Region	1	2	3	4	5	6	7	8	9	10
2000	12	2	6	10	3	5	9	1	1	50
2001	12	2	6	11	3	6	9	2	1	51
2002	12	2	6	11	3	6	9	2	1	53
2003	12	2	7	12	4	7	10	2	2	57
2004	12	2	6	11	4	7	11	3	3	58
2005	12	2	6	11	4	7	11	3	5	62
2006	12	2	6	9	4	11	14	4	8	69
2007	10	3	8	9	3	12	13	4	10	73
2008	10	0	8	10	2	8	12	0	6	57
2009	11	0	7	10	2	6	12	0	6	55
2010	10	0	5	10	2	2	11	0	5	45
2011	10	0	6	8	2	3	11	0	6	45
2012	10	0	5	3	2	1	11	0	5	38
2013	10	0	5	3	1	0	12	0	6	37
2014	11	0	5	3	0	0	6	0	5	30
2015	10	0	6	3	0	0	6	0	5	30
2016	5	0	2	3	0	-1	0	0	5	16
2017	3	-1	2	3	0	0	0	0	6	13
2018	3	0	2	3	0	0	0	0	6	14
2019	3	0	2	3	0	0	0	0	5	14
2020	3	0	2	3	0	0	13	0	6	27

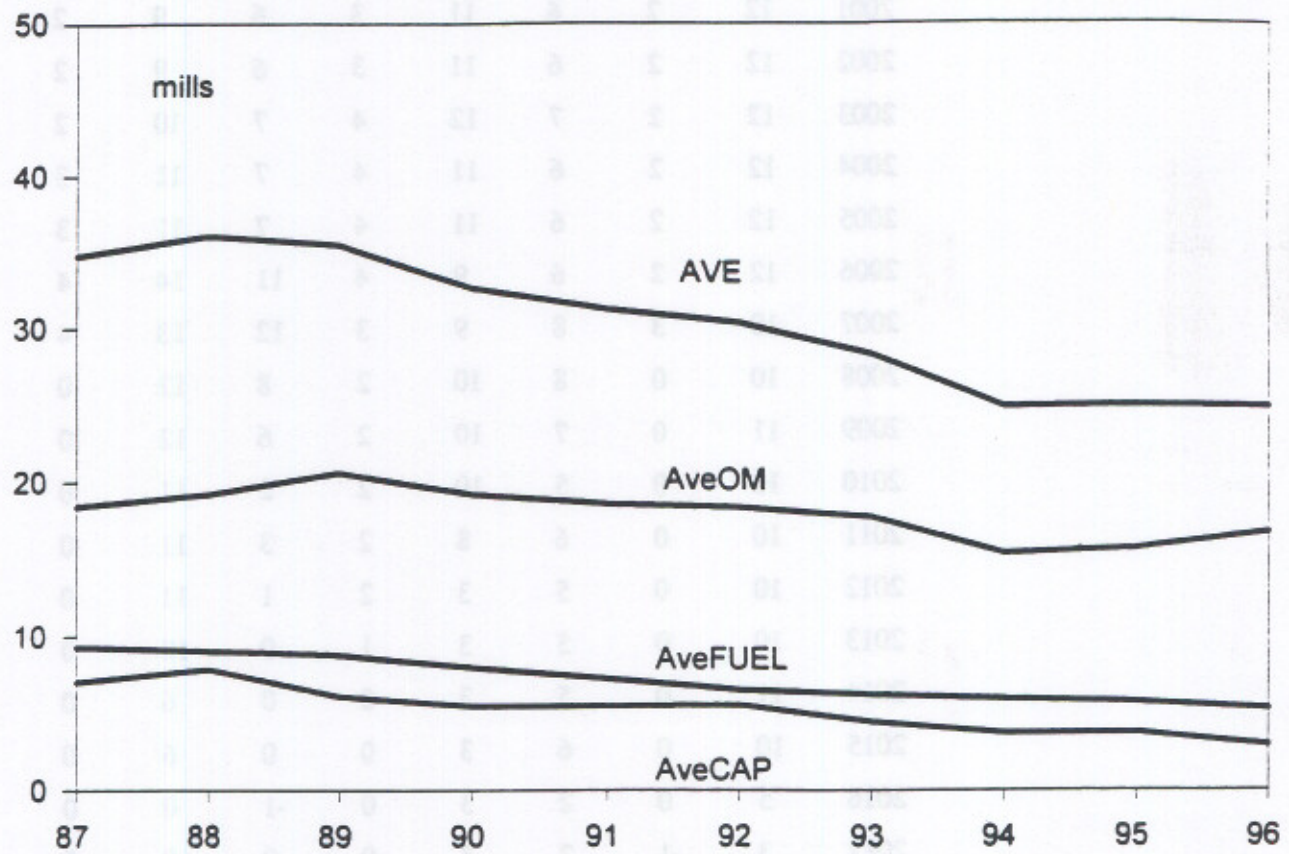
Figure 1: Average Variable Expenses, 1987-1996

Figure 2: Distribution of Average Variable Expenses, 1990 and 1995

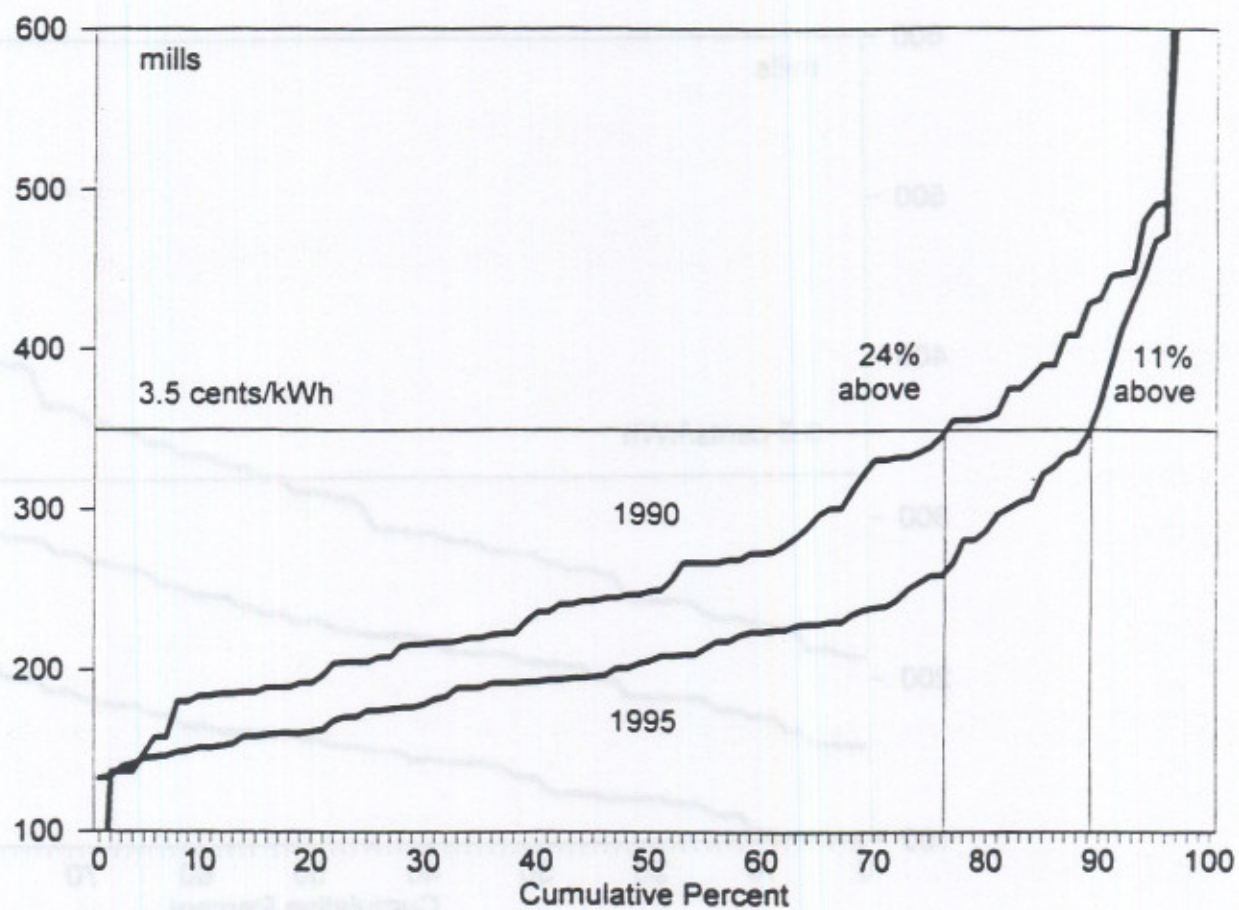


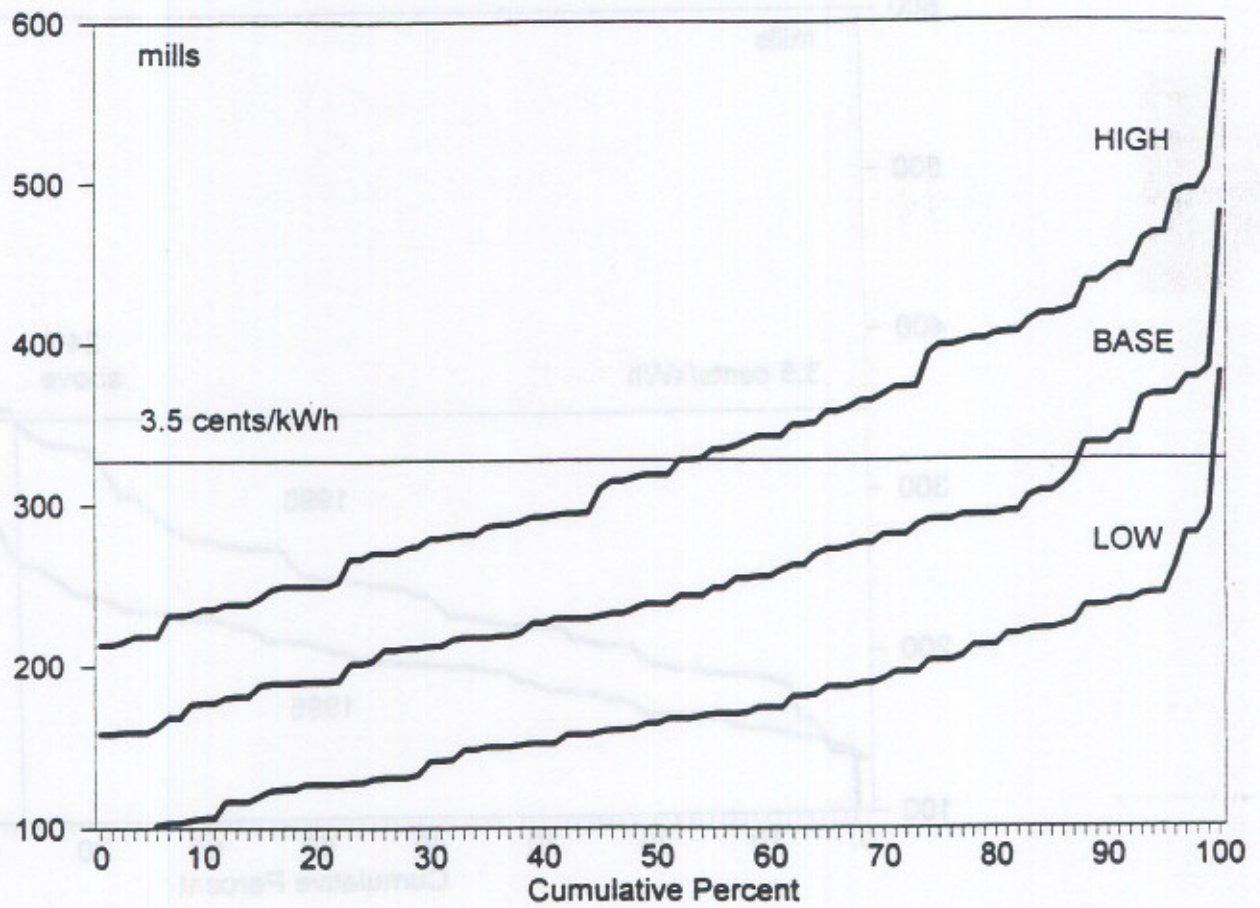
Figure 3: Cumulative Distribution of AVE Forecast at 75% Capacity Factor, 2000

Figure 4: Annual Capacity Factors, 1975-1995

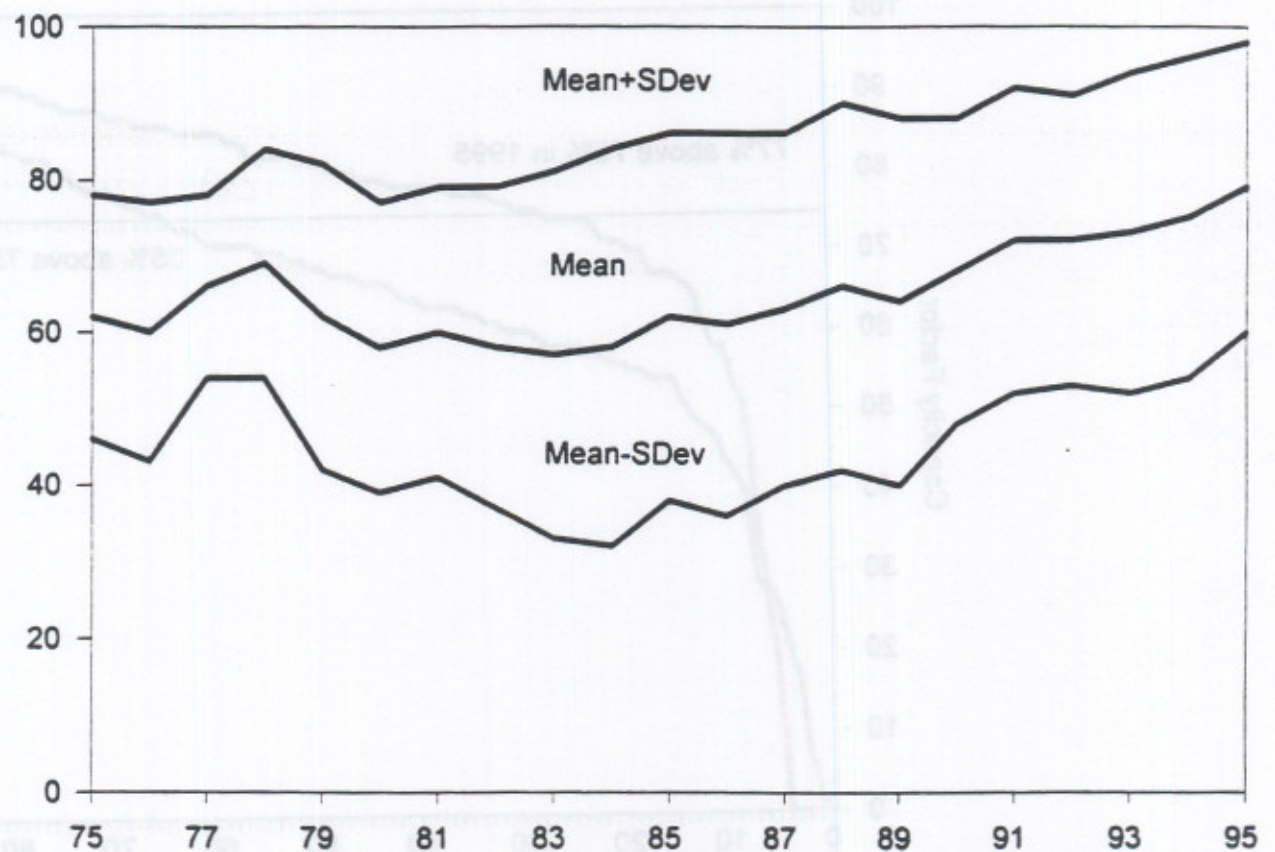


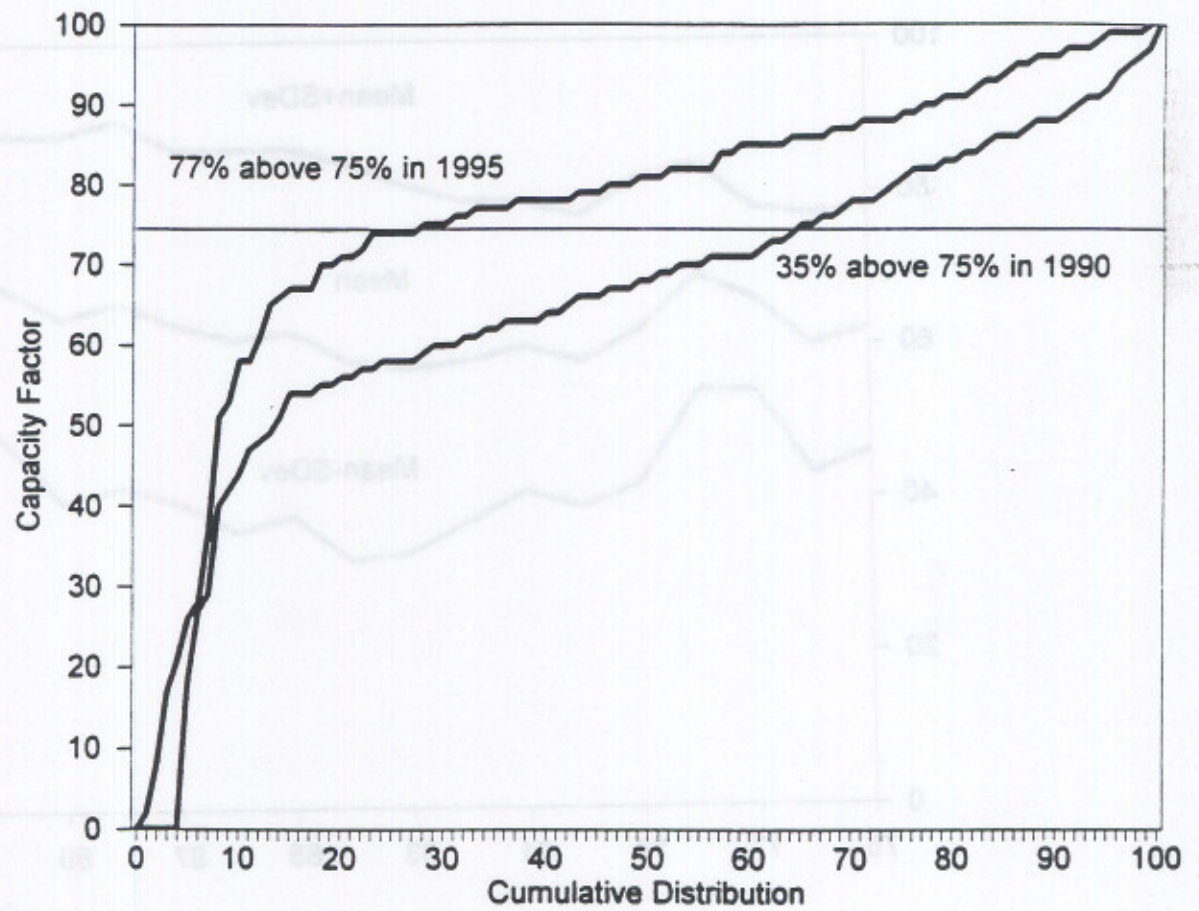
Figure 5: Cumulative Distribution of Capacity Factors, 1990 and 1995

Figure 6: Cumulative Distribution of Capacity Factor Forecast with a 90% Confidence Interval for the year 2000

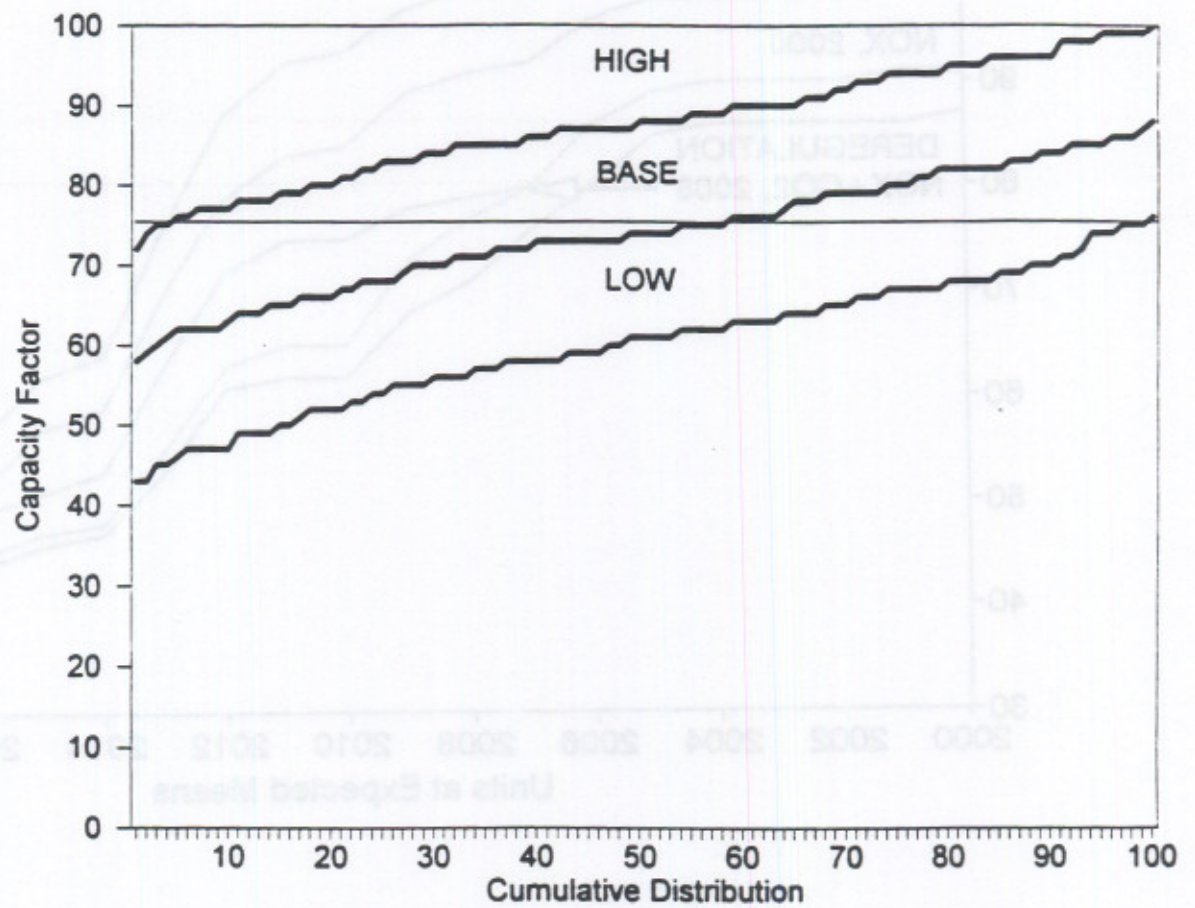


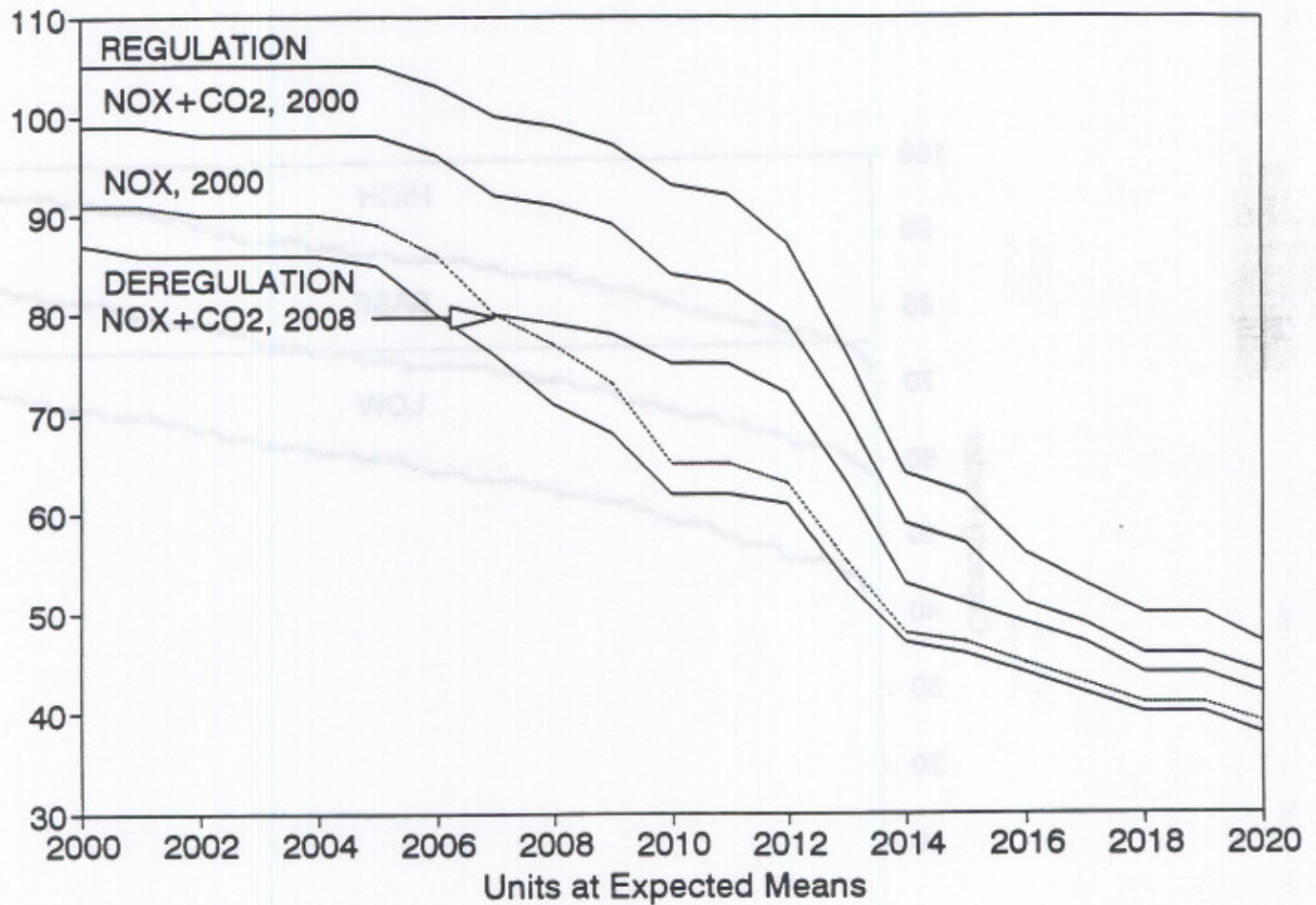
Figure 7: Nuclear Power Units at Forecast Means, 2000-2020

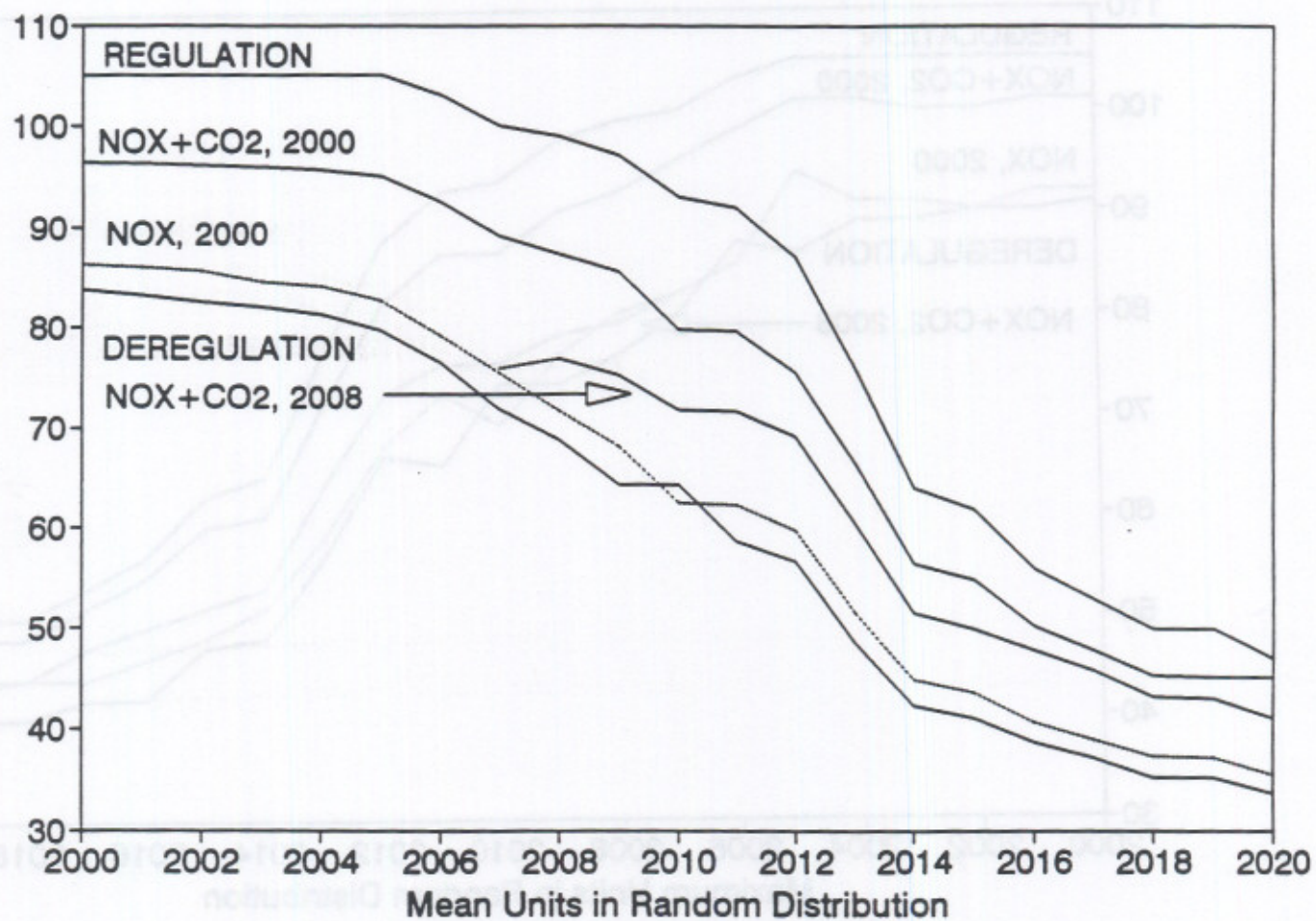
Figure 8: Nuclear Power Units at Means of Random Distributions, 2000-2020

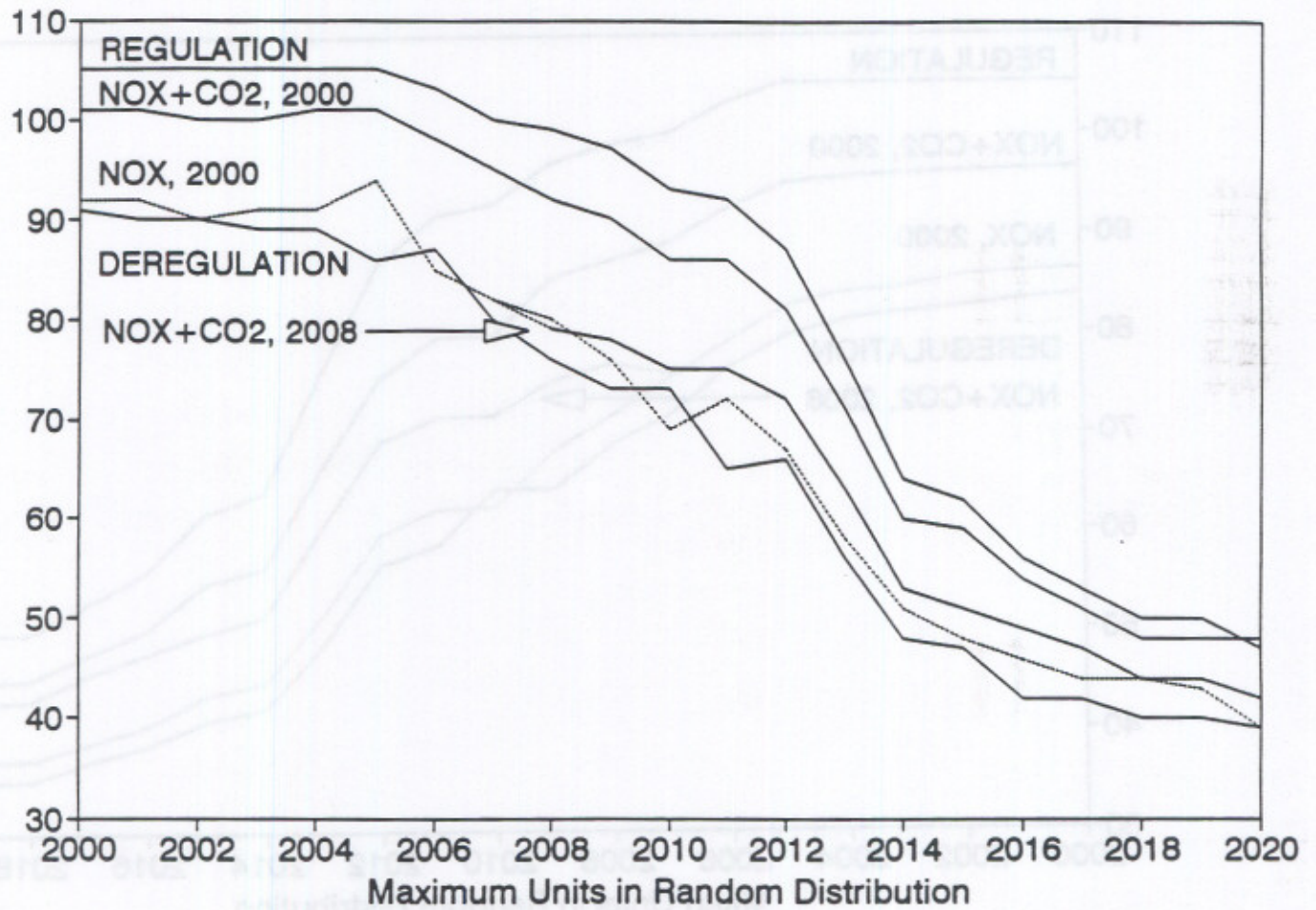
Figure 9: Nuclear Power Units at Maximum of Random Distribution, 2000-2020

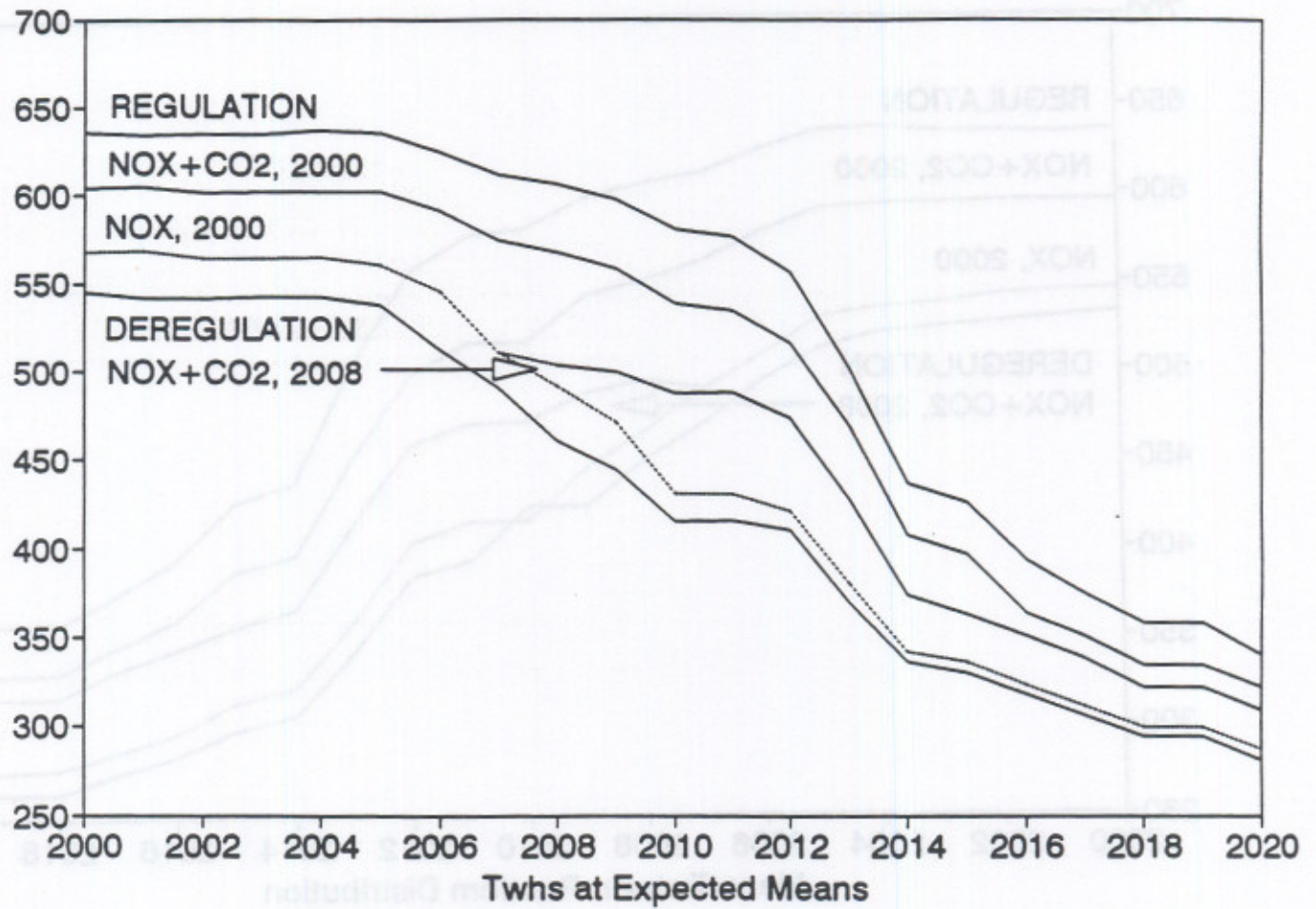
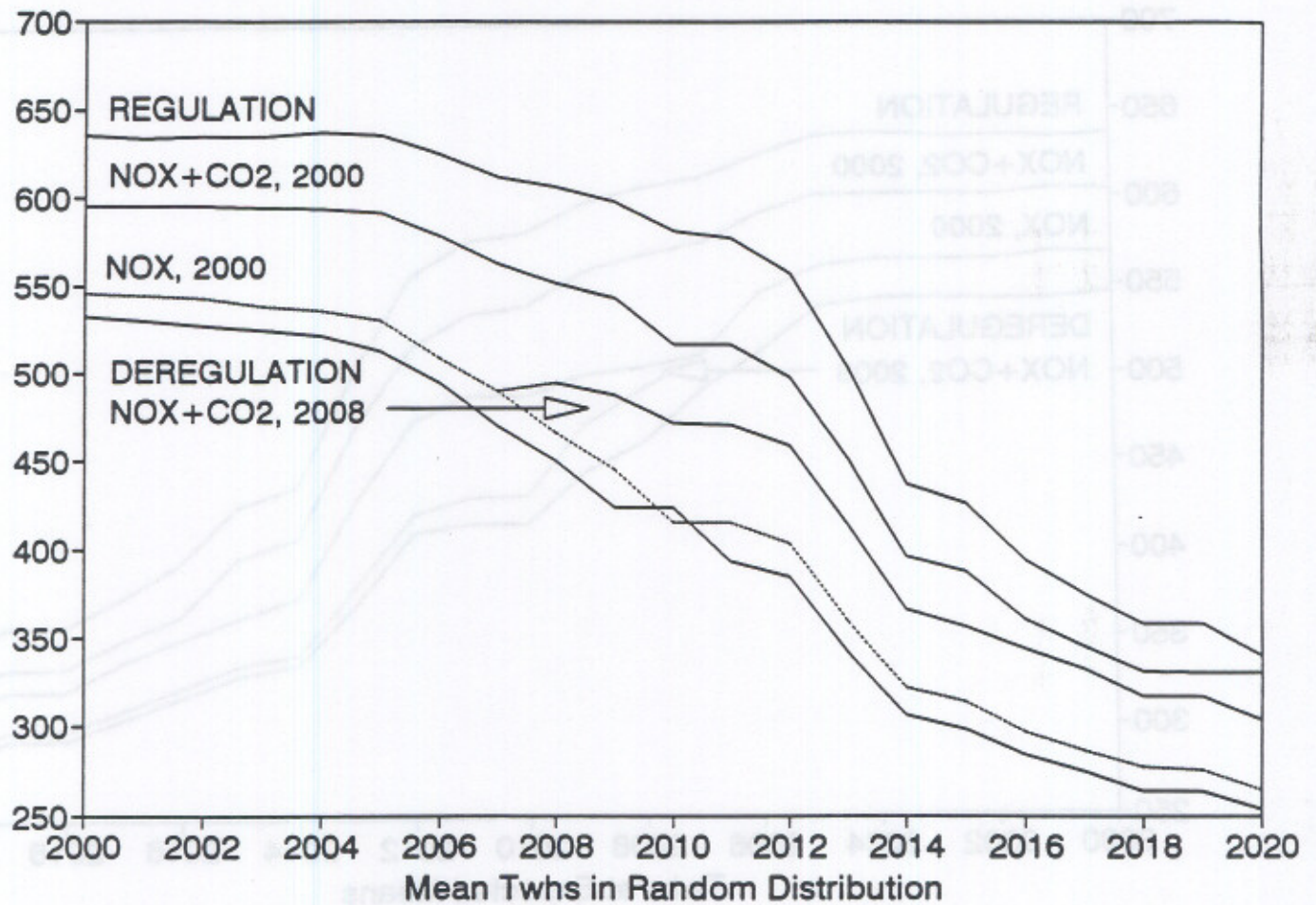
Figure 10: Nuclear Power Output in Terawatthours at Expected Means, 2000-2020

Figure 11: Nuclear Power Output in Terawatthours Random Distribution, 2000-2020



**Figure 12: Nuclear Power Output in Terawatthours
at Maximum of Random Distribution, 2000-2020**

