DIRECT TESTIMONY OF

DR. LEWIS J. PERL

ON BEHALF OF HOUSTON LIGHTING & POWER COMPANY

RE ENERGY ALTERNATIVES

TESTIMONY

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HOUSTON LIGHTING & POWER CO.

Q. Would you please state your name and address?

A. My name is Lewis J. Perl. My business address is Five World Trade Center, New York, New York.

Q. What is your present employment?

A. I am Senior Vice President of National Economic Research Associates, Inc., an economic consulting firm specializing in the economics of energy, the environment, antitrust, and labor.

Q. Would you briefly describe your educational and employment background prior to your association with National Economic Research Associates, Inc.?

A. I received my B.S. degree in industrial and labor relations from Cornell University in 1963. I received my M.A. degree in 1968 and my Ph.D. degree in 1970, both in economics from the University of California at Berkeley. From 1968 and to 1972, I taught economics at the New York State School of Indust.) and Labor Relations at Cornell University. Both in teaching and in my gradua. program, my fields of specialization were labor economics, econometrics and economic history.

Q. Would you describe the nature of your consulting work with National Economic Research Associates, Inc.?

1 A. National Economic Research Associates, Inc. (NERA) was established
2 in 1961 to offer economic consulting services in a number of fields, with
3 particular emphasis on regulated industries and their problems.

4 Since joining NERA in 1972, I have been responsible for a variety of
5 studies relating to the economics of energy and the environment. These
6 include numerous analyses of the comparative costs of coal and nuclear
7 generation for presentation in licensing and other regulatory proceedings. In
8 addition, I have done analyses of the costs of air and water pollution control
9 for the electric utility industry, as well as various comparisons of the costs
10 and benefits of specific environmental programs. I have directed a number of
11 econometric studies of the elasticity of demand for electricity, the elasticity
12 of demand for telephone service, and the price of uranium. I have been
13 involved in the development of a model for projecting coal prices and a variety
14 of studies evaluating the economics of alternative energy sources.

15 Q. Have any of your writings been published?

16 A. I am the author of numerous economic papers which have appeared in
17 such professional journals as the Quarterly Journal of Economics, the Journal
18 of Human Resources, and such publications as Nuclear News, Nations'
19 Business, The Wall Street Journal, The New York Times, and The Los Angeles
20 Times. In addition, I have given speeches on energy and environmental related
21 topics before the Atomic Industrial Forum and the World Energy Conference.

22 Q. Of what professional, honorary societies and industry groups are you a
23 member?

24 A. I am a member of the American Economic Association and the Air
25 Pollution Control Association.

26 Q. Dr. Perl, what is the purpose of your testimony?

1 A. The purpose of my testimony is to examine the need for and
2 desirability of the Allens Creek nuclear plant as a component of Houston
3 Lighting & Power's (HL&P) generation expansion plan in the next decade. My
4 examination of need consists of two basic components. First, I have examined
5 the expected cost of electricity from the Allens Creek facility and from a
6 number of alternative coal-fired electric generating plants. The objective of
7 this part of my testimony is to estimate the savings, if any, to consumers from
8 constructing Allens Creek and to determine the sensitivity of these savings to
9 uncertainties as to the costs and operating characteristics of both coal and
10 nuclear facilities. In the second part of my testimony, I have attempted to
11 examine the impact of uncertainties as to demand growth and the effect of
12 conservation policies on the need for and desirability of the Allens Creek
13 facility.

14 Q. Would you summarize the results of your analysis?

15 A. Yes. My comparison of Allens Creek with coal-fired alternatives
16 suggests that, using the most likely assumptions as to each of the components
17 of cost, the cost of electricity from Allens Creek would be significantly
18 cheaper than that from either subbituminous or lignite coal plants. While
19 there were substantial uncertainties in the costs of both Allens Creek and a
20 coal-fired alternative, the <u>expected</u> cost of electricity from the Allens Creek
21 facility was still less than those of any of the coal-fired alternatives
22 considered. With respect to the subbituminous alternative, the differences in
23 expected costs were substantial, but the lignite alternative had only slightly
24 higher expected costs than Allens Creek. Thus, assuming that HL&P needs to
25 add some baseload capacity over the next 10 years, there would be savings to
26 consumers from building Allens Creek; if significant lignite reserves are

1 feasible these savings are modest, but if subbituminous fuel must be used the
2 savings would be substantial.

3 Since there are substantial uncertainties in both coal and nuclear
4 generating costs, a wide range of costs is possible whichever option is
5 selected, and cost uncertainties are somewhat greater for nuclear than for
6 coal alternatives. As a consequence, no single choice of a generating option
7 provides absolute assurance of minimum cost. Given these uncertainties, a
8 utility trying to maintain low cost and also reduce uncertainty would develop a
9 generation expansion plan containing some mix of coal and nuclear capacity.

10 The second component of this analysis indicated that the need for and
11 the economic desirability of the Allens Creek facility were insensitive to the
12 uncertainties in load forecasting or the success of conservation and load man-
13 agement policies. Because of the very substantial dependence of HL&P's
14 current system on oil- or gas-fired capacity and the very high expected costs
15 of those fuels, there would be substantial economic advantages to the
16 construction of the Allens Creek facility, even if conservation policies were
17 sufficient to eliminate all of the growth in demand expected over the next
18 decade. This would be true even if conservation programs significantly
19 reduced system load factors. Moreover, load management policies, to the
20 extent they were successful in shifting peak demand to off-peak periods,
21 would increase the economic savings from the construction of Allens Creek.

22 The cost-minimizing generation expansion plan for HL&P includes an
23 enormous expansion of new baseload capacity, either coal- or nuclear-fired.
24 These capacity additions would be required to meet load growth and to reduce
25 the system's uneconomic dependence upon oil and natural gas. It seems
26 unlikely that all of these capacity requirements can be met, even if Allens

1 Creek and all feasible coal additions are made. This reflects both environ-
2 mental and fuel supply limits on coal expansion. If, as seems likely, the
3 expansion of coal capacity is limited, the development of Allens Creek is best
4 viewed as a means for reducing dependence on oil and gas. In this context, the
5 economic advantages of constructing this plant are substantial and implausibly
6 large increases in the capital costs of constructing this facility would be
7 required to reverse this economic advantage.

8 Q. Dr. Perl, can you summarize your analysis of the comparative costs of
9 Allens Creek and electricity from coal-fired plants?

10 A. Yes. This analysis involved comparing the levelized cost of electricity
11 from the Allens Creek plant, assuming completion in 1989 with the costs of
12 electricity from either a subbituminous or a lignite coal plant completed in the
13 same time frame. The results of this analysis are described in Figure 1.
14 Capital costs, nonfuel operating and maintenance (O&M) costs and capacity
15 factors for each of these alternative facilities were derived based upon a
16 statistical analysis of data for plants completed over the last decade. Fuel
17 costs for both Allens Creek and each of the coal alternatives were derived
18 from coal and uranium demand and supply models developed by NERA.

19 Using the most likely values for the cost components of each of these
20 alternatives, the levelized costs of electricity from the Allens Creek facility
21 would be 9.4 cents per kilowatt-hour while that from a subbituminous coal
22 plant would be 11.6 cents per kilowatt-hour and that from a lignite-fired coal
23 plant, 10.4 cents per kilowatt-hour. Assuming an equivalent lifetime supply of
24 energy from both the coal and nuclear alternatives, the discounted present
25 value of the savings from Allens Creek would be $418 million if the alternative
26 is a subbituminous plant and $192 million if the alternative is a lignite plant.

The present value of total electricity costs for each of the three alternatives considered is summarized in Figure 2.

As is indicated in Figure 1, the costs of coal and nuclear plants represent a substantially different mixture of capital and operating costs. For the nuclear facility, capital costs constitute nearly two-thirds of total electricity costs. However, for the coal facilities, capital costs constitute less than one-third of total operating costs. The analysis suggests that the lower operating costs of nuclear plants offset their higher capital costs over the lives of these facilities.

It is quite important to note that each of the components of cost for both Allens Creek and its alternatives is subject to a substantial margin of uncertainty. For capital costs, capacity factors and nonfuel operating and maintenance costs, this reflects a substantial variation from unit to unit in historic costs and performance. For fuel costs, this reflects uncertainties as to the future demand and supply of these fuels.

In choosing among the alternatives several approaches can be used to account for these uncertainties. One approach is to assign a probability to each of the possible values for each cost component and use these probability distributions to estimate the <u>expected</u> costs of electricity for each of the alternatives. These expected values may be different from <u>deterministic</u> values described above because of the skewed distribution of specific cost components and because the formulae for levelized costs tend to produce skewed cost distributions, even when each of the cost components is symmetrically distributed. A comparison of expected costs for each of these alternatives is described in Figure 3. When the comparison is based on expected values, the levelized cost of electricity from Allens Creek, at 10.2

cents per kilowatt-hour, is still less than that from either the subbituminous plant (11.8 cents) or the lignite plant (10.7 cents). In each case, the expected values of levelized cost are somewhat above the deterministic values described in Figure 1. This reflects the skewness of the probability distributions underlying these values. In addition, as a result of somewhat greater skewness in the probability distribution for nuclear than for coal costs, the expected cost for Allens Creek is closer to the expected costs of the coal-fired alternatives than was the case for the deterministic values. Despite this narrowing of the range, there are still substantial savings in expected costs from constructing Allens Creek. The present value of these savings is $315 million when the alternative is a subbituminous plant and $100 million when the alternative is a lignite plant. These results are summarized in Figure 4.

While a comparison of expected costs still favors the nuclear option, there is substantial uncertainty surrounding these expected values. This uncertainty has several important implications. First, whichever of these options is selected, there is a significant probability that costs will be either greater or less than the expected values described above. Thus, for the nuclear plant, an 80 percent confidence interval of cost produces a cost band ranging from 7.5 to 13.3 cents per kilowatt-hour. For coal alternatives, the band, while narrower, is still quite wide--from 9.8 to 14.1 cents for the subbituminous alternative and from 8.5 to 13.1 cents for the lignite alternative. These confidence bands are described in Figure 3.

Second, since these probability distributions exhibit substantial overlap, there is no way to guarantee that the alternatives selected will be, in fact, lowest cost. Thus, for a subbituminous alternative, there is a 77 percent chance that coal costs exceed nuclear costs, but a 23 percent that coal costs

are less than or equal to nuclear costs. For the lignite alternative, there is a 62 percent chance that nuclear costs are less than coal costs but a 38 percent chance that coal costs are less than or equal to nuclear costs.

Finally, given the substantial uncertainties in cost for both coal and nuclear plants and the fact that these uncertainties are largely uncorrelated with one another, it may be desirable for HL&P to consider a generation expansion plan which contains both coal and nuclear units. While such a plan would have expected costs which were higher than those of an all-nuclear system, the associated variability in cost would be substantially reduced. HL&P's current expansion plan represents such a mix; 30 percent of planned additions over the next 10 years are nuclear and 70 percent are coal.

Q. Can you now describe in somewhat more detail your analysis of the need for the Allens Creek facility and its sensitivity to conservation and load management policies?

A. In addition to the cost factors described above, in general the economic desirability of the Allens Creek facility depends upon the expected future demand for electricity in the HL&P service territory, the availability of coal-fired alternatives and the cost and availability of existing generating facilities. If expected demand growth is rapid, this increases the need for baseload generation and, since Allens Creek is the most economic source of baseload generation, for this facility in particular. In addition to demand growth, demand for Allens Creek (or other baseload plants) depends on the cost of electricity from existing generating facilities. Where these costs are high, as is the case with gas and oil units, it may be economic to construct Allens Creek or other baseload facilities even in the absence of any growth in demand. Finally, the availability of coal alternatives to Allens Creek may be

limited by fuel availability and environmental requirements. If overall requirements for additional generating capacity are sufficiently large, these requirements may exceed maximum feasible coal additions. In this case, the economic advantages of Allens Creek would be based not on a comparison with coal costs, but with the costs of existing oil-fired or gas-fired capacity.

In order to determine the sensitivity of the need for Allens Creek to load growth, the cost of existing facilities, and coal availability, it was necessary to solve a relatively complex optimization problem. This optimization problem involved determining the mix of capacity necessary to meet forecasted loads on the HL&P system at lowest cost and the sensitivity of this mix of capacity additions to alternative assumptions regarding load growth, cost and capacity availability.

In order to solve this optimization problem, I developed a linear programming model of the HL&P system. Given a specification of the expected demands for electricity by time period and a description of the availability and operating costs of existing generating plants, this linear programming model was used to determine the pattern of capacity additions and generation needed to meet these demands at lowest cost. The results of this analysis are summarized in Figure 5.

In the first case, this linear programming model was used to estimate capacity and generating requirements assuming that the company's forecast of growth in demand was accurate. Using this forecast, peak demand in 1990 would be 15,050 megawatts and total energy requirements would be 86.9 thousand gigawatt-hours. Existing capacity in 1980 is 11,763 megawatts and plants currently under construction and those planned for construction during the 1980s would add 6,340 megawatts to this total, bringing capacity in 1990

to 18,103 megawatts. Planned capacity additions, consist of Allens Creek (1,130 megawatts), other nuclear capacity (770 megawatts), and various coal units (4,440 megawatts). Under these plans, the system reserve margin on peak would be 20.3 percent with and 12.8 percent without Allens Creek. In evaluating the need for capacity additions, 1990 oil prices (in 1979 dollars) were assumed to be $25.56 per barrel and gas prices were $4.60 per MCF. While these prices are probably too low, assumptions of higher prices would simply reinforce the conclusions reached.

When the linear programming model was used to test this plan, all of the additions proposed by HL&P were made, but the model results indicated that an additional 6,742 megawatts of coal capacity would be required to meet load at minimum cost. Thus, the cost-minimizing expansion plan required 13,082 megawatts of capacity additions, and, if feasible nuclear additions were limited to Allens Creek and the South Texas Project, 11,182 megawatts of this capacity would be coal-fired. Moreover, if Allens Creek were not available, 12,297 megawatts of coal capacity would be required to meet demand at lowest cost. This expansion plan is compared with the current plan, with and without Allens Creek, in Figure 5. This result clearly indicates that the decision to construct Allens Creek is justified given HL&P's load forecast and the cost of existing operating capacity.

Moreover, it seems unlikely that the amount of coal fired capacity required by the cost minimizing plan, either with or without Allens Creek, could be constructed over the next ten years. First, it exceeds current plans by nearly 7,000 megawatts and planning and constructing this amount of coal fired capacity would prove difficult with HL&P's current resources. Under the cost minimizing expansion plan 52.0 million tons of lignite coal would be

1 required annually by 1990. A 20-year supply of coal for these plants would
2 require a reserve of 1.0 billion tons, which is more than 55 percent of all
3 proven reserves of Texas lignite coal. Since there are many competitors for
4 this coal, it is unlikely that HL&P can secure a coal reserve of this magnitude
5 except at exorbitant prices. While subbituminous coal reserves are not
6 similarly limited, energy from subbituminous coal plants would be significantly
7 more expensive.

8 In addition to constraints on coal supply, the operation of the large
9 volume of coal capacity specified above would pose significant environmental
10 problems. Total sulfur oxide emissions from these plants, even with maximum
11 feasible controls, would be 87,000 tons annually. These emissions are likely to
12 create problems in complying with PSD or non-attainment provisions of the
13 Clean Air Act.

14 These factors suggest that the amount of coal capacity available to
15 meet load growth and achieve an economic reduction in oil dependence, with
16 or without Allens Creek, is likely to be constrained well below the amount
17 required to minimize cost. The existence of these constraints increases the
18 need for the Allens Creek facility.

19 To illustrate the effect of coal constraints on need, I have used the
20 linear programming model to calculate the expected savings to consumers in
21 1990 from constructing Allens Creek with and without such constraints.
22 Assuming unlimited ability to construct lignite capacity, the savings to
23 consumers from constructing Allens Creek would be $47.9 million annually by
24 1990. On the other hand, if lignite and other coal additions are constrained to
25 6,540 megawatts over this period (which is still 2000 megawatts in excess of
26 current plans), the annual savings from constructing Allens Creek would be

$245 million. In estimating these savings, I have used levelized annual capital costs for Allens Creek and its alternatives which assume no further inflation after 1990. These estimates are summarized in Figure 6.

The very large consumer savings from Allens Creek which occur if coal additions are constrained imply that substantial increases in the capital cost of the Allens Creek facility could be experienced without eliminating its advantage. Thus, the expected capital cost of Allens Creek is $1,855 per kilowatt. If unlimited coal expansion were feasible, increasing this cost by 22 percent to $2,261 would cause the linear programming model to reject Allens Creek as part of the least cost plan. On the other hand, assuming coal additions are constrained to 6,540 megawatts, the capital cost of Allens Creek would have to increase to $4048 per kilowatt before it would be removed from the cost-minimizing plan. These numbers are summarized in Figure 7.

Q. What conclusion did you draw from this analysis?

A. Given expected load growth, the Allens Creek facility is an economically desirable component of HL&P's generation expansion plan. Moreover, since the economically optimal generation expansion plan requires more coal additions than are likely to be feasible, the expected savings to consumers from constructing Allens Creek substantially exceeds the difference in cost between coal and nuclear plants, and reflects instead the difference in cost between operating existing oil- or gas-fired plants and the levelized cost of electricity from Allens Creek.

Q. What would be the effect on this result of reductions in demand projections which would result if forecasted growth were too high or if explicit conservation policies could reduce growth below forecasted levels?

1 A. Reduction in demand growth, within a plausible range, does not appear
2 to alter these conclusions. To test this, the demand forecasts described above
3 were first reduced to the low end of the range employed by HL&P. This
4 resulted in a peak demand of 13,550 megawatts in 1990. This is well below the
5 low end of Dr. Anderson's forecast range which suggests a minimum of 14,044
6 megawatts in 1990. Even at this demand level, however, 11,539 megawatts of
7 capacity additions were required to meet 1990 demands at lowest cost. This is
8 still 5,199 megawatts in excess of current plants. Of this total, 1,130
9 megawatts represents Allens Creek, 770 represents other nuclear and the
10 balance of 9,639 represents coal capacity. Even this represents far more coal
11 capacity than is likely to prove feasible over this period. The results of this
12 analysis are summarized in Figure 8.

13 While still lower growth does not appear to be plausible, a similar
14 analysis was also done assuming no growth in electricity between 1980 and
15 1990. In this case peak demand in 1990 would be 10,200 megawatts. Even in
16 the absence of any load growth, the optimal generation expansion plan called
17 for the addition of 8,268 megawatts of additional capacity and this plan
18 included Allens Creek, South Texas Project and 6,368 megawatts of coal
19 capacity. Even at this lower load forecast, the minimum cost expansion plan
20 included nearly 2,000 megawatts of capacity in excess of current HL&P plans.

21 In short, the need for the Allens Creek generating facility appears to
22 be independent of forecasted growth in electricity demands in the Houston
23 area. Since no conservation program or combination of nonconventional
24 alternatives to electric generation is likely to produce zero growth in electric
25 generation for the HL&P service territory, it would appear that the need for
26

1 the Allens Creek facility is essentially independent of the effectiveness of
2 such conservation policies.

3 It should be noted that in addition to reducing overall load growth,
4 most conservation policies are likely to erode the system load factor. This
5 occurs because such policies tend to be more effective in reducing off-peak
6 than in reducing peak demands. In order to test the sensitivity of my
7 conclusions to conservation policies which reduce the system load factor, I
8 have examined the optimal generation expansion plan for the HL&P system
9 --assuming both no growth in load between now and 1990 and an erosion of the
10 current load factor from 66 to 60 percent. By comparison with the no growth
11 case described above, this reduces overall energy demand by over 10 percent
12 between 1980 and 1990, while leaving peak demand unchanged. As shown in
13 Figure 9, even with this erosion in total energy requirements, the optimal
14 generation expansion plan requires 7,083 megawatts of additional capacity
15 including Allens Creek, the South Texas Project and 5,183 megawatts of coal
16 capacity. This is still in excess of current planned additions and suggests that
17 even this erosion in energy demands would not eliminate the economic
18 desirability of Allens Creek or other components of HL&P's current generation
19 expansion plan.

20 Q. Have you evaluated the effect on these conclusions of load man-
21 agement policies which increase rather than decrease load factor?

22 A. While the most likely direct effect of conservation policies is to
23 reduce the system load factor, there are load management policies which
24 might improve system load factor by shifting some demands from the peak to
25 the off-peak periods. In particular, time-of-day, seasonal or tempera-
26 ture-sensitive pricing might accomplish this result. In order to determine the

1 sensitivity of the demands for Allens Creek to load management policies, I
2 assumed no growth in energy requirements for the period 1980 to 1990 and, in
3 addition, assumed an improvement in the system load factor so that the
4 overall load factor was 100 percent. This change reduced peak demand to
5 6,721 megawatts, which is well below the current level. While such an
6 improvement is obviously not attainable in practice, I considered this case in
7 order to test the limits of the sensitivity of demand for Allens Creek to the
8 load factor. In this case, the requirements for capacity additions were 7,677
9 megawatts of additional capacity, which included Allens Creek, South Texas
10 Project and 5,777 megawatts of coal capacity. This is still in excess of
11 current plans and indicates that even the most extreme improvement in
12 system level factor combined with a "no growth" conservation program would
13 not eliminate the need for Allens Creek.

14 The overall results of this analysis can be summarized briefly. It
15 would appear that the economic desirability of the Allens Creek facility is
16 essentially insensitive to conservation policies, even those that would reduce
17 to zero the expected load growth of the system over the period 1980 to 1990.
18 Even if these conservation policies also tended to erode the system load
19 factor, this would still not eliminate the need for or the economic desirability
20 of the Allens Creek facility. Load management policies which improve the
21 system load factor would tend to increase the system's requirements for
22 capacity additions and, consequently, the need for the Allens Creek facility.
23 Given the very substantial dependence of the current HL&P system on
24 capacity fired by oil and gas, the need for capacity additions, either coal or
25 nuclear capacity, are very large. Assuming that no nuclear capacity beyond
26 Allens Creek and South Texas Project can be constructed over the next

1 decade, the requirements for coal capacity probably exceed the amount which
2 can be built, given the environmental requirements and the ability to secure
3 reliable coal reserves.

4 Q. Can you describe in somewhat more detail the methodology used to
5 derive the capital costs, operating and maintenance costs and capacity factors
6 used in this analysis for coal and nuclear plants?

7 A. Yes. For each of these factors, estimates used in this study were
8 based on a statistical analysis of data on a sample of generating units
9 constructed over the last 15 years. Multiple regression analysis was used to
10 relate capital costs, operating and maintenance costs and capacity factors for
11 each of these plants to a number of plant characteristics. Equations derived
12 from this analysis were used to predict costs and operating characteristics for
13 Allens Creek and for subbituminous and lignite coal-fired units.

14 The equation for projecting nuclear capital costs is described in Table
15 1. As indicated, the determinants of costs include: the date on which the unit
16 received its construction permit; the time required to license the unit; the
17 wage rate of construction labor in the area in which the plant was constructed;
18 the size of the unit in megawatts; the number of nuclear units previously
19 licensed by the architect/engineer (A/E) responsible for designing or con-
20 structing the facility; a variable which distinguishes between single unit
21 plants, the first unit of a multiple unit plant, and the second or subsequent unit
22 of a multiple unit plant; a variable which distinguishes between plants built in
23 the Northeast section of the country and elsewhere; and a variable which
24 distinguishes between units built with and without cooling towers. Taken
25 together, these variables account for nearly 90 percent of the historic
26 variation in construction costs for nuclear facilities.

For coal plants, the determinants of capital cost, as described in Table 1, are the date the unit was completed, the size of the unit in megawatts, a variable distinguishing between the first unit at a site and second or subsequent units, the wage rate prevailing in the area in which the plant is constructed, a variables distinguishing between plants built with and without scrubbers, and variables which distinguish among plants built in various regions of the country.

For both coal and nuclear units, these equations express the log of construction costs per kilowatt of capacity as a linear function of these determinants. As a result of this choice of functional form, each unit change in the determinants of cost is associated with a constant percentage change in cost per kilowatt. Where the determinants of cost are also measured in logarithmic terms, as is the case for wages and unit size, each percentage change in the independent variable produces a constant percentage change in cost per kilowatt. The cost projected by these equations are expressed in constant 1979 dollars, exclusive of allowance for funds used during construction.

In using these equations to project the capital costs for Allens Creek and the alternative coal unit, several assumptions were made. First, it was assumed that, except for escalation in input costs, there would be no additional escalation in construction costs for coal and nuclear plants beyond that which had occurred through 1979. Thus, costs for units completed in 1979 were used to forecast costs of units completed in 1989, adjusting only for escalation in labor and materials costs in the intervening period. Although costs for both coal and nuclear plants have escalated over the past few years at a rate which substantially exceeded the rate of escalation in labor and

1 materials costs, we did not feel that there was any empirical basis for
2 extrapolating the historic rate of cost escalation into the future.

3 Second, for coal facilities, it was assumed that the construction would
4 take seven years from start to completion, whereas for the Allens Creek
5 facility it was assumed that seven and a half years would be required. During
6 the construction period, costs were assumed to escalate for both facilities at a
7 rate of 8.5 percent per year and interest on funds used during construction was
8 assumed to equal 7.5 percent per year. In computing the book value of these
9 facilities at the time of completion, I assumed that interest expenses on 6[illegible]
10 percent of construction costs would be included in rates during the construc-
11 tion period and the balance would be capitalized. For the nuclear facility,
12 licensing time was set equal to 27 months and A/E experience was derived by
13 calculating the number of units licensed by Ebasco prior to Allens Creek.

14 Third, in deriving the capital costs for the coal facility, a separate
15 equation was used to estimate scrubber costs. This reflects the fact that
16 scrubber costs are very sensitive to the sulfur content of the fuels used and
17 the percent of sulfur reduction required and, consequently, the simple dichot-
18 omous scrubber variable in the econometric equations would not suffice to
19 estimate these costs. For particulates a similar approach was used. The
20 estimates of scrubber and particulate cost as derived from engineering models
21 are described in Table 2.

22 Fourth, the coal facilities which were examined in the regression
23 analysis included bituminous, subbituminous, and lignite plants but most of the
24 plants analyzed were bituminous facilities. Because of the lower heat content
25 of subbituminous and lignite fuels, the capital costs of these facilities tend to
26 be somewhat higher than those of bituminous plants. Using data derived from

1 a study by United Engineers and Constructors, I estimated that each 10
2 percent decline in the heat content of the fuel used in a coal-fired plant
3 increased the capital cost by 0.11 percent and this was used to adjust base
4 capital costs to reflect the heat contents of the fuels used in the subbitumin-
5 ous and lignite plants studied.

6 Fifth, the size variable used in predicting the capital costs of coal
7 plants measures gross capacity. For nuclear plants, the size variable measure
8 the net electric capacity. In order to express costs in comparable terms, costs
9 for both coal and nuclear facilities were expressed per kilowatt of net
10 capacity and, for coal plants, net capacity was assumed to be equal to 90
11 percent of gross capacity.

12 Finally, it should be noted that a lignite coal facility constructed by
13 HL&P would, in all likelihood, be situated in or near the lignite coal fields.
14 This would make this facility somewhat more distant from HL&P's load center
15 than either a subbituminous plant or the Allens Creek facility. To account for
16 this difference, the capital costs of any additional transmission facilities
17 needed to bring power from each of these facilities to the HL&P system are
18 included in the plant capital cost estimate.

19 The resultant capital cost estimates for the Allens Creek facility, a
20 subbituminous coal plant, and a lignite coal plant are described in Table 2. In
21 each case, these costs reflect the gross book value of these plants at the time
22 of completion. It should be noted that these costs include direct construction
23 costs and accumulated allowance for funds used during construction on that
24 portion of construction work in progress not included in the rate base during
25 the construction period. In addition to the mid-point values, which are $1,855
26 per kilowatt for Allens Creek, $1,020 per kilowatt for the subbituminous plant

1 and $1,107 per kilowatt for the lignite plant, this table also describes the 80
2 percent confidence band around these estimates. This 80 percent confidence
3 band has been derived using the standard error of estimate from the regression
4 results described above. For the Allens Creek plant, the range of projected
5 capital costs is from $1,440 to $2,389 per kilowatt, for the subbituminous plant
6 it is from $762 to $1,365 per kilowatt, and for the lignite plant it is from $827
7 to $1,482 per kilowatt.

8 The procedure used to derive nonfuel operating and maintenance costs
9 for coal and nuclear plants is quite similar to that used to derive capital costs.
10 The O&M cost equations are described in Table 3. For coal plants, the
11 determinants of O&M costs are unit size, the number of units at a site,
12 prevailing wage levels for utility employees, variables which distinguish among
13 various regions of the country, and a variable reflecting the date on which the
14 plant came on-line. The same variables are used to predict the O&M costs for
15 nuclear plants but, in addition, there appears to be a relationship between the
16 age of a nuclear plant and its operating and maintenance costs. For sampled
17 coal plants, the regression equation explained 90 percent of the variation in
18 annual operating costs while for nuclear plants the equation explained 87
19 percent of this variation. For both coal and nuclear plants, the O&M costs of
20 the most recent plants appear to be somewhat lower than plants built earlier.
21 In projecting costs for future facilities, however, I did not assume that this
22 declining cost trend would continue. In addition, the data for nuclear plants
23 suggest that O&M costs rise with age, but that the rise largely levels-out by
24 the fifth or sixth year of operation and declines thereafter. Since data on
25 nuclear plants with more than 5 to 6 years of operation are limited, I assumed
26 that O&M costs remained constant, except for the effects of inflation, after

1 the fifth year. Plant O&M costs for both coal and nuclear facilities, are
2 described in Table 4. The costs in this table are expressed both in constant
3 1979 dollars and in levelized dollars over the life of these facilities. In
4 estimating levelized costs, I assumed that labor and materials inputs to these
5 operating and maintenance costs would inflate at 5.5 percent per year over the
6 life of these facilities. As with the capital costs, I have indicated both the
7 mid-point of costs and the 80 percent confidence interval. This interval was
8 derived based upon the standard error of these regression equations.

9 In addition to plant operating and maintenance costs, scrubber and
10 particulate removal systems impose additional O&M costs on coal-fired
11 facilities. The O&M costs used to develop the estimate described above do not
12 reflect these scrubber or particulate costs, since most of the facilities on
13 which these estimates were based do not have scrubbers or the type of
14 particulate systems required by current environmental regulation. The O&M
15 costs for coal facilities were augmented by scrubber and particulate O&M
16 costs derived from an engineering model of these costs. Table 4 also contains
17 these estimates.

18 In order to express capital and nonfuel operating and maintenance
19 costs per kilowatt-hour of generation, it is necessary to determine the annual
20 generation which will be achieved by either the nuclear facility or the coal
21 alternative. For coal facilities, I derived the achievable capacity factor from
22 historic data on the equivalent availability of coal-fired units. Equivalent
23 availability measures the percentage of time a unit is partially or fully
24 available to meet electricity load. For periods in which a unit is partially
25 available to meet load, equivalent availability reflects the percentage of total
26

capacity which is available. If a unit could be used fully whenever it was available, annual generation would equal:

$$MWH = EA * CAP * HOURS$$

where: MWH = annual generation in megawatt-hours;
EA = equivalent availability;
CAP = net capacity in megawatts;
HOURS = hours in the year (8,760 normally and 8,784 for leap years).

In these cases, unit capacity factor (the ratio of generation to the product of capacity and hours in the year) would equal equivalent availability. In practice, even the most economic baseload units achieve capacity factors which average about 90 percent of equivalent availability. This reflects system loading constraints which prevent even the most economic units from being fully utilized. Consequently, for coal units, the maximum achievable capacity factor was set equal to 90 percent of equivalent availability. The equation used to forecast the equivalent availability factor of individual units, which is summarized in Table 5, relates equivalent availability to size, age, first-year equivalent availability and sulfur content. Equivalent availability appears to decline as size increases, to increase with age and to decrease with sulfur content.

For nuclear units, I estimated the relationship between capacity factor and plant characteristics directly, and this relationship is also described in Table 5. The capacity factor for nuclear units appears to be related to size,

age, and vintage of the unit. Capacity factor appears to be a decreasing function of size, to increase with age, and to be better for more recent units. The capacity factor equation described here reflects only the performance of BWR units which appear to exhibit a somewhat different pattern of performance than PWR units. Allens Creek is a BWR unit.

The predicted capacity factors for coal units and for the Allens Creek facility are described in Table 6 along with their confidence intervals. For the coal facility, the predicted capacity factor was 68 percent. For nuclear plants, two capacity factors were estimated. When the vintage trend was not extrapolated, the projected capacity factor was 61 percent. When vintage was extrapolated into the late 80s the projected capacity factor was 73 percent. Giving relatively modest weight to this vintage effect, we assumed a 65 percent capacity factor for the nuclear unit.

Q. Dr. Perl, can you indicate how the nuclear fuel estimates used in your testimony were derived?

A. Yes. The cost of nuclear fuel consists of five separate components: the costs of uranium oxide or, enrichment, conversion, fuel fabrication, and waste disposal.

With respect to the first of these factors, NERA has developed a model which estimates uranium oxide prices as a function of both supply and demand factors. In this model, the demand for uranium oxide is derived from projections of nuclear generating capacity coming on-line through the end of the century. This demand is adjusted judgmentally to exclude imports and to include exports and, therefore, represents demand for U.S. uranium oxide production. The initial supply of uranium oxide used in this model is derived from the existing data on U.S. reserves, classified by their cost of extraction.

1 Future uranium reserves are projected using an econometric equation which
2 relates discoveries of uranium to exploratory and developmental drilling
3 activity. As modelled, supply in any one year is a function only of reserves
4 previously discovered on which mines and mills have been established. This
5 estimate of supply, in conjunction with an estimate of demand provides an
6 estimate of equilibrium price for the year in question. The equilibrium price
7 of uranium in the initial year, in turn, determines the mining industry's
8 investments in new mines and mills and the level of exploratory effort.
9 Development of new mines and mills and the discovery of new reserves then
10 determine reserves available in future years. Sequential analysis of supply and
11 demand over time provides a trajectory of uranium oxide prices. The prices
12 used in this analysis on a year-by-year basis through 2020 are described in
13 Table 7. A range of prices has been developed reflecting alternative forecasts
14 of demand.

15 Estimates of the costs of each of the other components of the nuclear
16 fuel cycle were derived based upon testimony of prepared by NUS for
17 proceedings scheduled by the Nuclear Regulatory Commission (NRC) on the
18 recycling of uranium and plutonium. The range of estimates for each of the
19 components are described in Table 8. Since these estimates reflect forecasts
20 of costs prepared by the NRC, the electric utility industry manufacturers of
21 nuclear fuel, and by intervenors in this proceeding, it seems reasonable to
22 suppose that these values reflect the full range of anticipated costs.

23 Q. Can you indicate how you derived costs of coal fuel used in this
24 analysis?

25 A. Yes. With respect to costs of coal, NERA also has developed a model
26 which projects equilibrium coal prices as a function of both supply and demand

1 factors. In this model data from the U.S. Bureau of Mines for each of 22
2 regions of the country are used to derive estimates of coal supply by sulfur
3 content and heat content. Reserves in each region are then further subdivided
4 by extraction cost to create coal supply curves for each coal type and region.
5 In addition to these data on supply, the model derives demands for coal by
6 sulfur and heat content for each of 21 regions of the United States. Using
7 data on transportation cost from each supply to each demand region, the
8 model then derives the equilibrium level of production for each coal reserve.
9 A pattern of production is derived which minimizes the national aggregate
10 cost of meeting these coal demands. Based upon the supply curves discussed
11 above and these estimates of coal demand, equilibrium prices for each fuel are
12 derived.

13 In estimating coal prices for subbituminous and lignite plants in Texas,
14 I examined the forecast of equilibrium prices to determine the lowest cost
15 source of fuel for coal plants constructed in the HL&P service territory. For
16 lignite plants, this involved using Texas lignite coal. For subbituminous plants,
17 coals from either New Mexico or from Wyoming could be lowest cost,
18 depending upon future demand, and consequently, the prices used reflect an
19 average of prices for coal from each of these regions. With respect to lignite,
20 the plant is assumed to be a mine mouth facility and so no transport costs are
21 involved. With respect to subbituminous coal, the transport costs from either
22 New Mexico or Wyoming to a site in Texas are calculated from equations
23 which forecast rail freight rates as a function of region and distance. Prices
24 of these fuels, at the mine and delivered, are described in Table 9. In deriving
25 the most likely value used in this analysis, I used estimates of the most likely
26

demand for coal while upper and lower bounds reflect higher and lower coal demands.

Q. Can you describe how the levelized cost of electricity was derived from these cost components?

A. Yes. The levelized cost of electricity is a constant annual charge for electricity which would have the same discounted present value as actual electricity charges over the life of the plant. This levelized cost was derived from the cost components described above using the following formula:

$$LC = \frac{\sum_{i=1}^{N} \left(\frac{CC * AF_i + OM_i}{CF_i * 8760} + FC_i \right) \frac{1}{(1+d)^i}}{\sum_{i=1}^{N} \frac{1}{(1+d)^i}}$$

where: CC = the book value of the capital cost of the unit per kilowatt of capacity;

AF_i = the annualization factor for capital cost in year i;

CF_i = the capacity factor of the plant in year i;

OM_i = nonfuel operating and maintenance costs per kilowatt of capacity;

FC_i = fuel costs per kilowatt-hour of generation;

d = the discount rate;

N = assumed life for the facility.

1 With the exception of the annualization factor and the discount rate,
2 all of the terms in this equation are described above. The annualization factor
3 is a number which when multiplied by the initial book value of the facility,
4 provides the cost of interest, amortization, taxes insurance, decommissioning,
5 and periodic decontamination. In calculating this factor, interest, amortiza-
6 tion and taxes are based upon financial data supplied by HL&P which are
7 described in Table 10. The interest costs during the operating life of these
8 facilities have been adjusted upward to include the costs of interest incurred
9 during the construction period.

10 In estimating decommissioning costs, I assumed that these would equal
11 10 percent of the initial cost of the facility plus the effect of nominal
12 escalation over the life of the facility. A sinking fund was used to derive an
13 annual decommissioning charge. A similar approach was used to fund
14 decontamination charges occurring in the 15th and 25th years. The decom-
15 missioning costs are derived from a study done by the Atomic Industrial Forum
16 (AIF) and the decontamination costs are from a study by Sargent & Lundy.
17 The adjustments to the annualization factor to reflect decommissioning and
18 decontamination are shown in Table 11.

19 Q. Dr. Perl, would you summarize your conclusions?

20 A. Yes. HL&P requires very substantial additions of baseload generating
21 capacity over the next decade. These capacity additions, which exceed
22 current plans, are required both to meet anticipated load growth and to reduce
23 oil dependence. Since the expected cost of electricity from Allens Creek is
24 lower than any of the alternative capacity additions examined, and lower than
25 the operating costs of existing gas or oil plants, this facility should be a part of
26 HL&P's expansion plan. Given the system's current substantial dependence on

oil and gas and probable constraints on expanding coal capacity significantly beyond current plans, the desirability of Allens Creek is largely independent of conservation and load management policies.

Figure 1

Levelized Electricity Cost From Allens Creek And Coal Alternatives

(Deterministic Values)

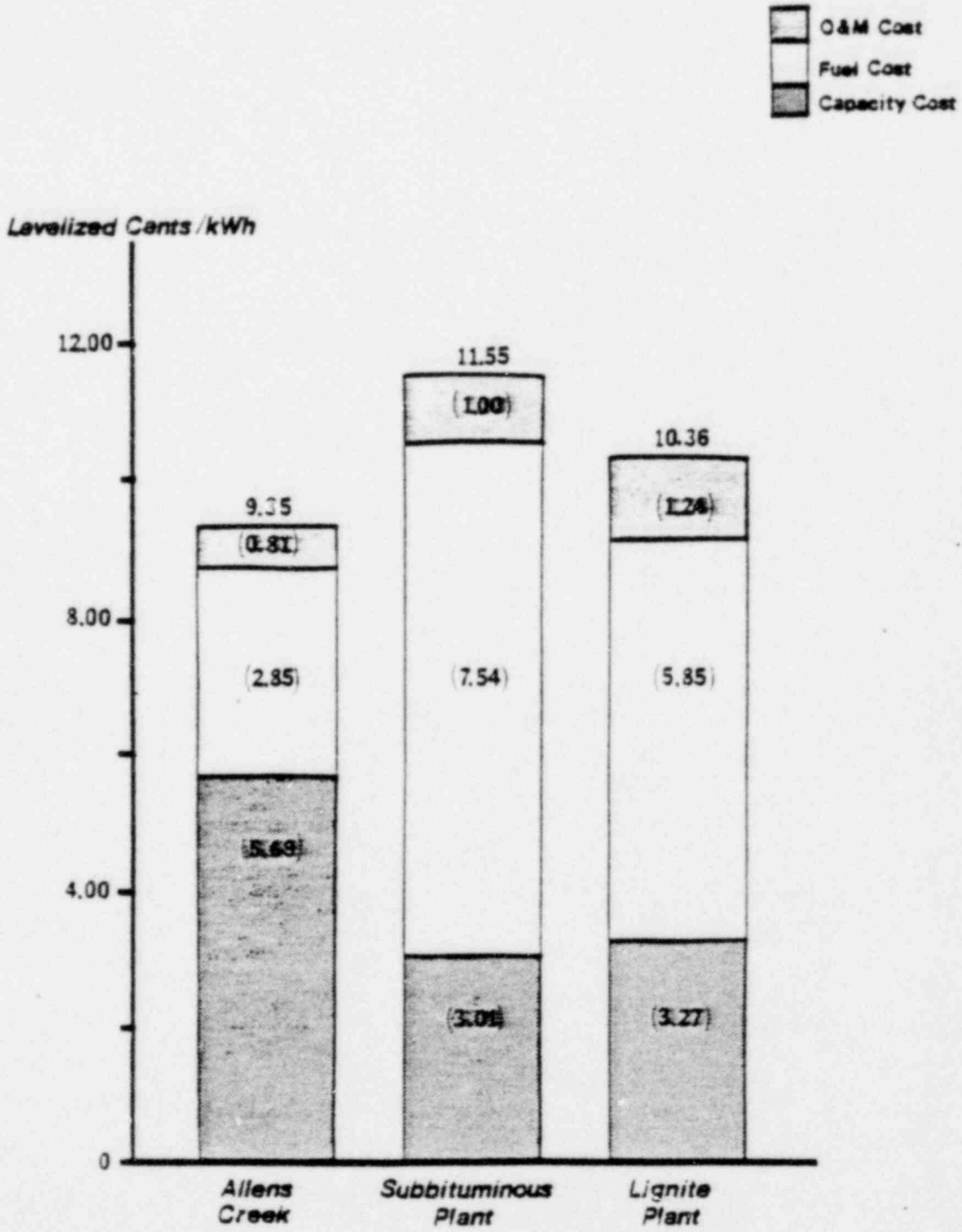


Figure 2

Discounted Present Value Of Electricity Costs From Allens Creek And Coal Alternatives

(Deterministic Values)

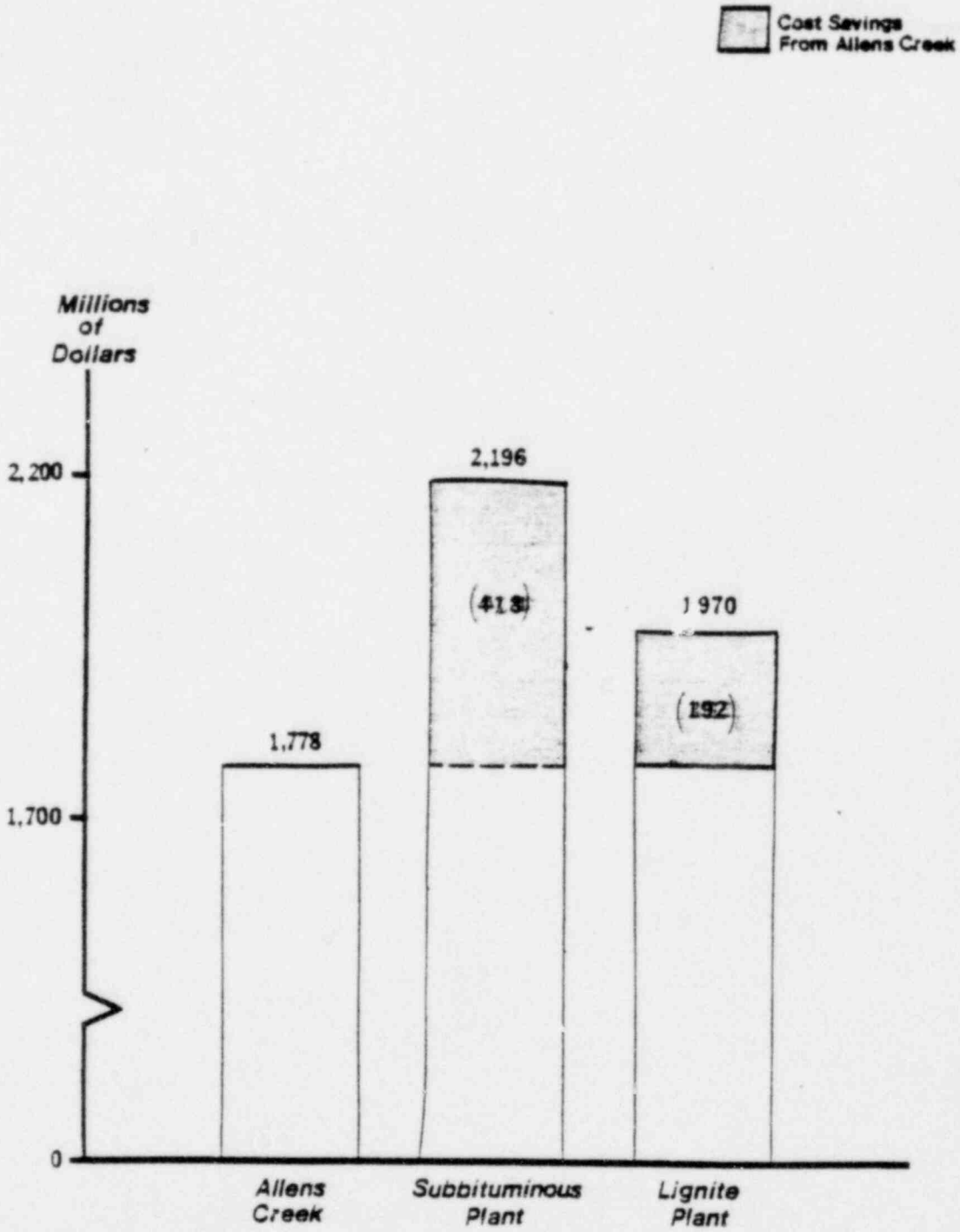


Figure 3

Probabilistic Distribution Of Levelized Electricity Cost From Allens Creek And Coal Alternatives

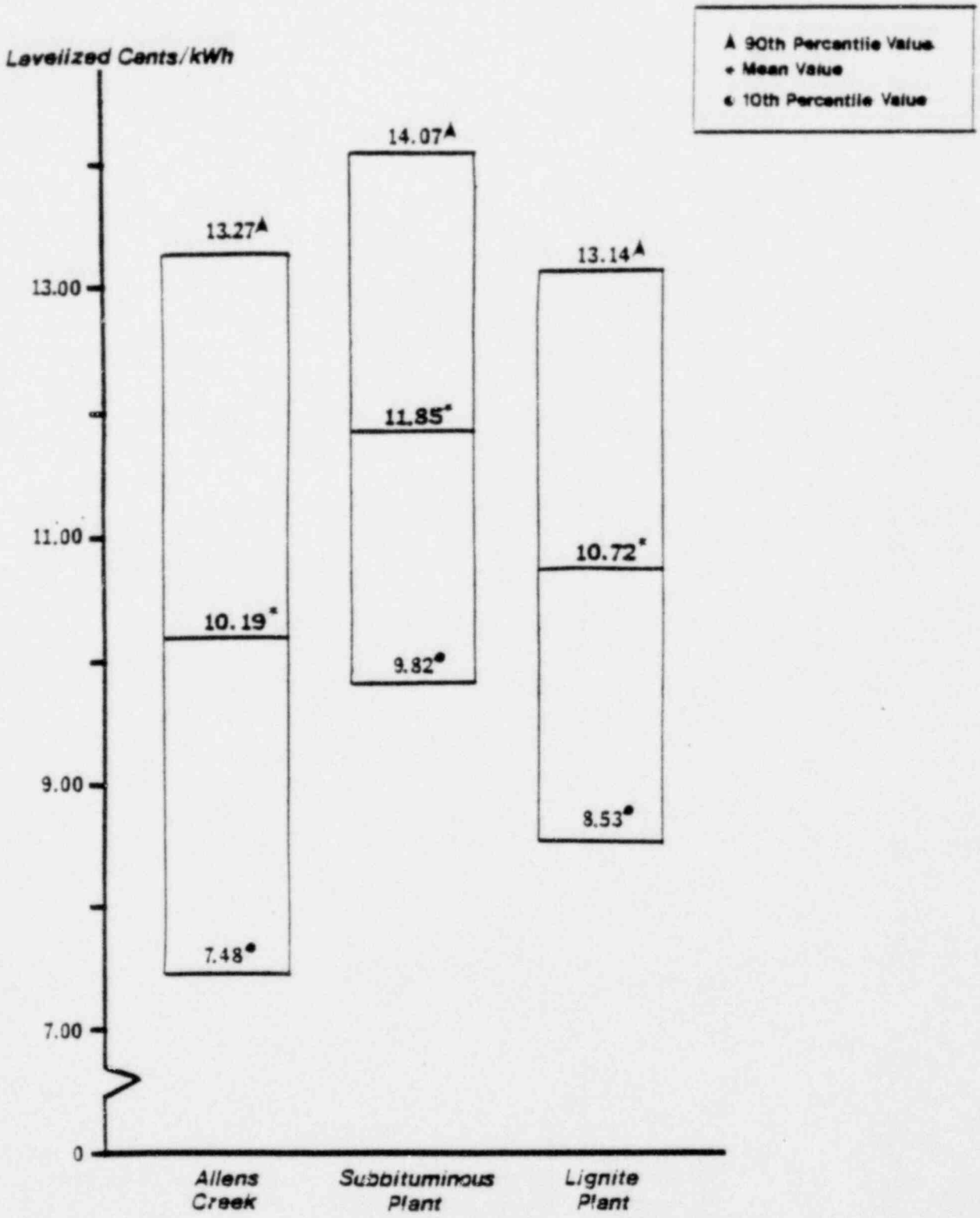


Figure 4

Discounted Present Value Of Electricity Costs From Allens Creek And Coal Alternatives (Expected Values)

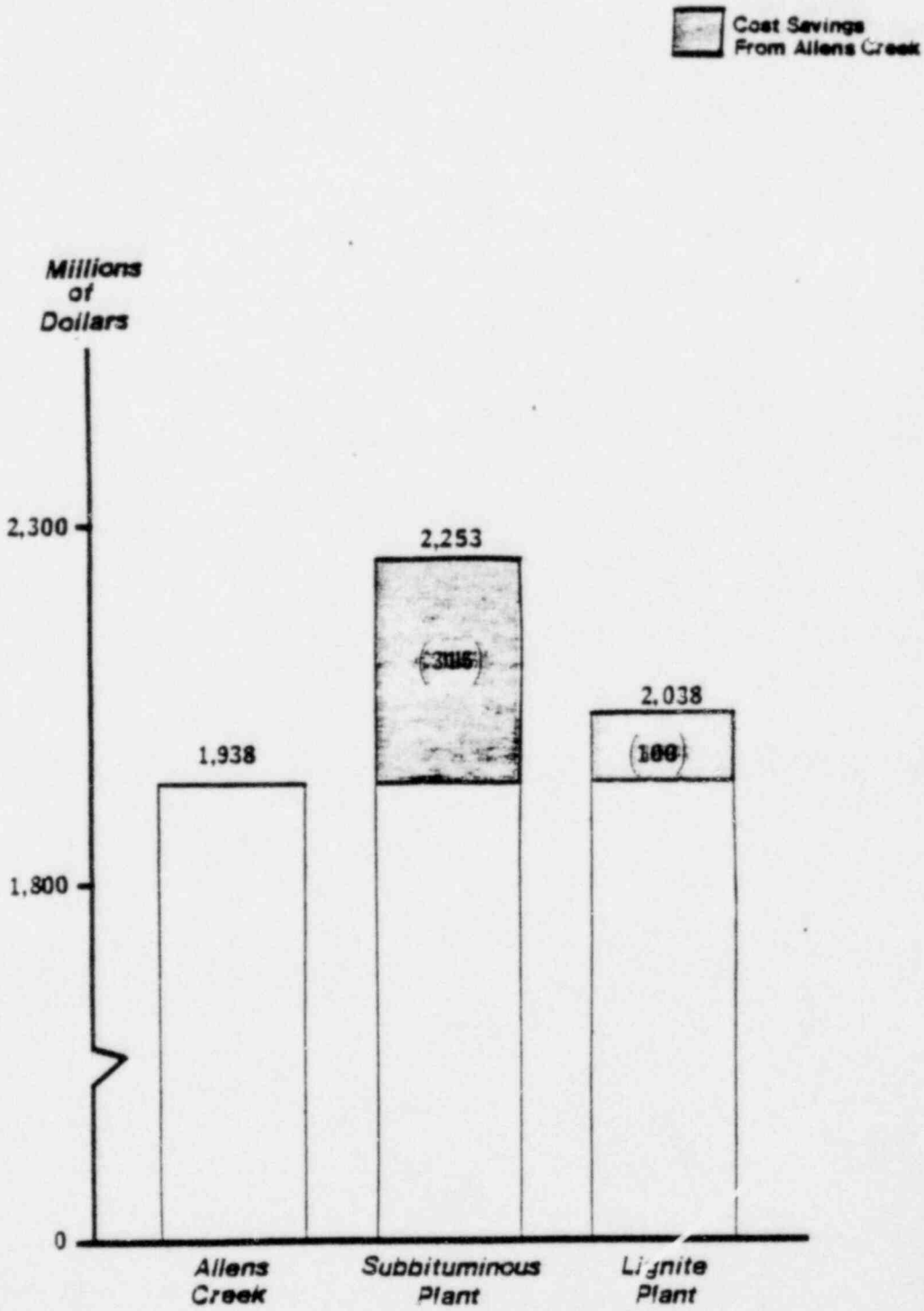


Figure 5

Alternative Capacity Expansion Plans For HL&P Through 1990
Medium Growth

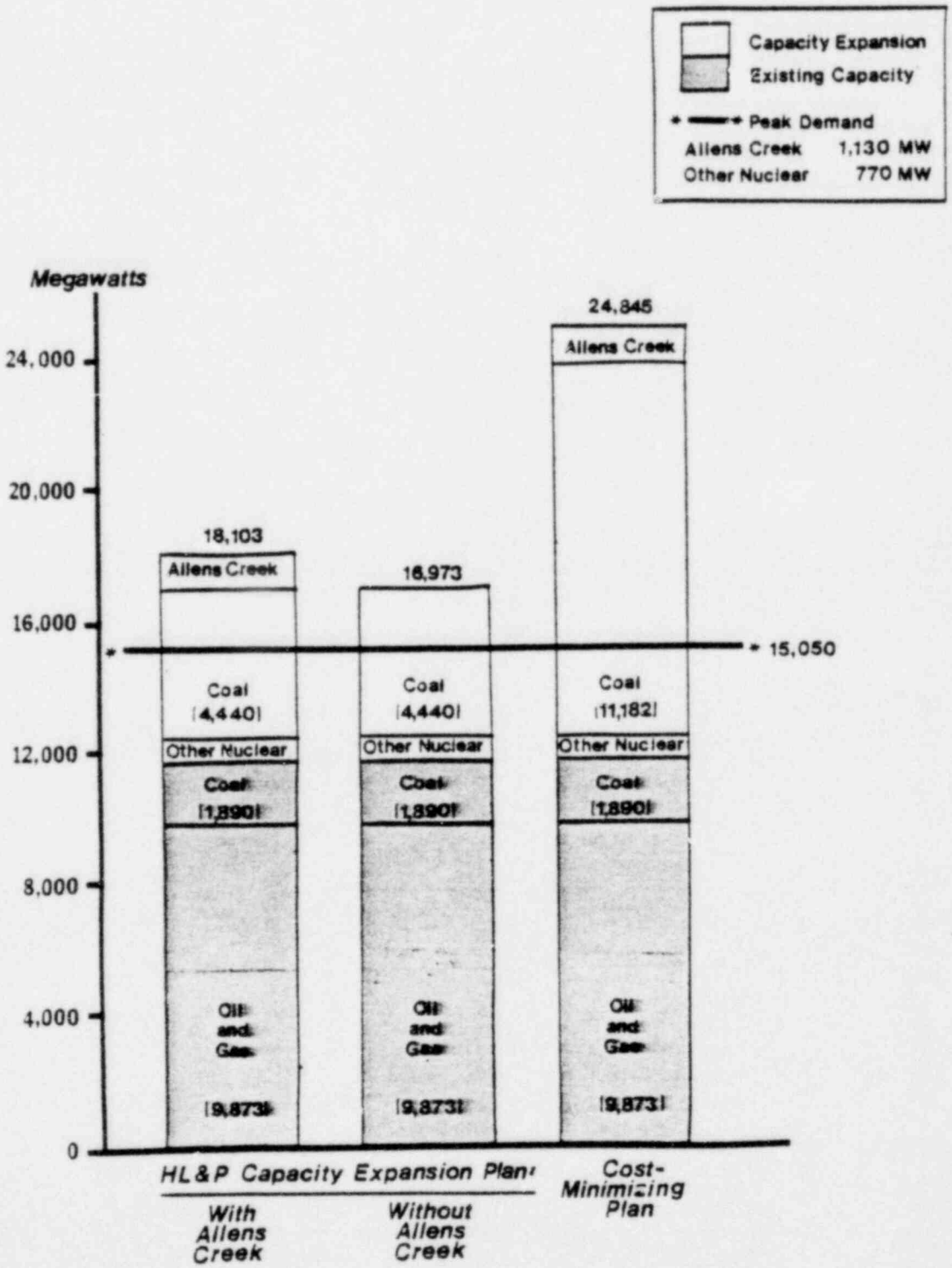


Figure 6

Savings In Electricity Costs In 1990 From Allens Creek

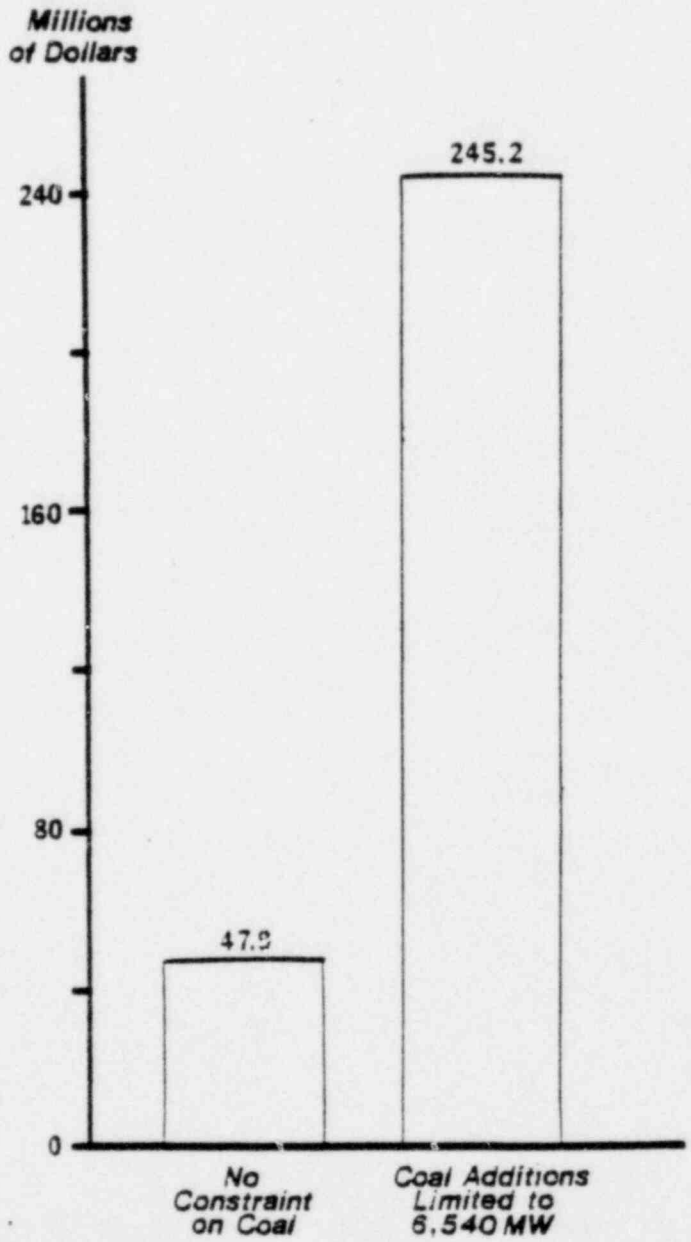
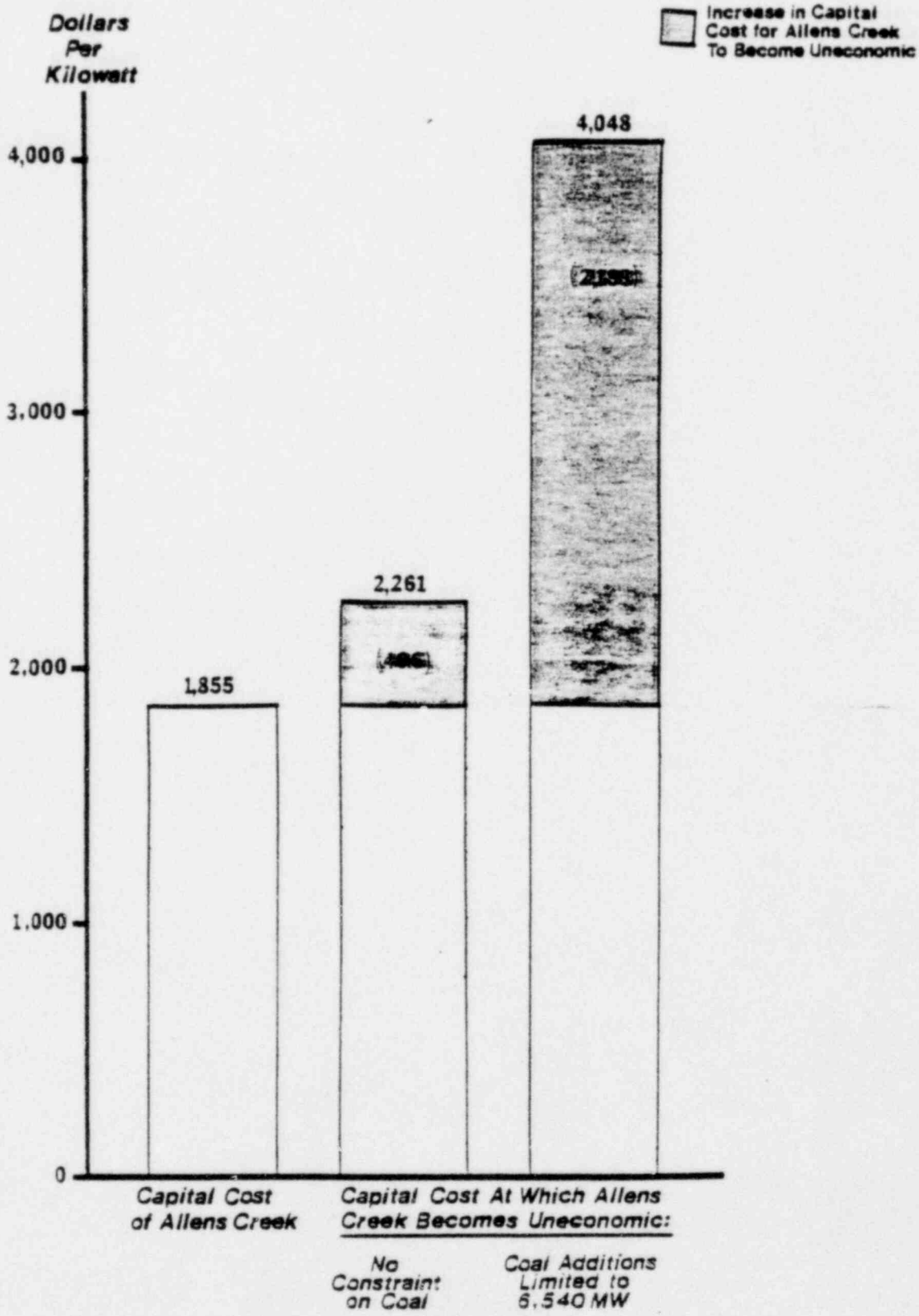


Figure 7

Capital Cost At Which Allens Creek Becomes Uneconomic



nera

Figure 8

Capacity Expansion Plans For HL&P Under Alternative Growth Assumptions

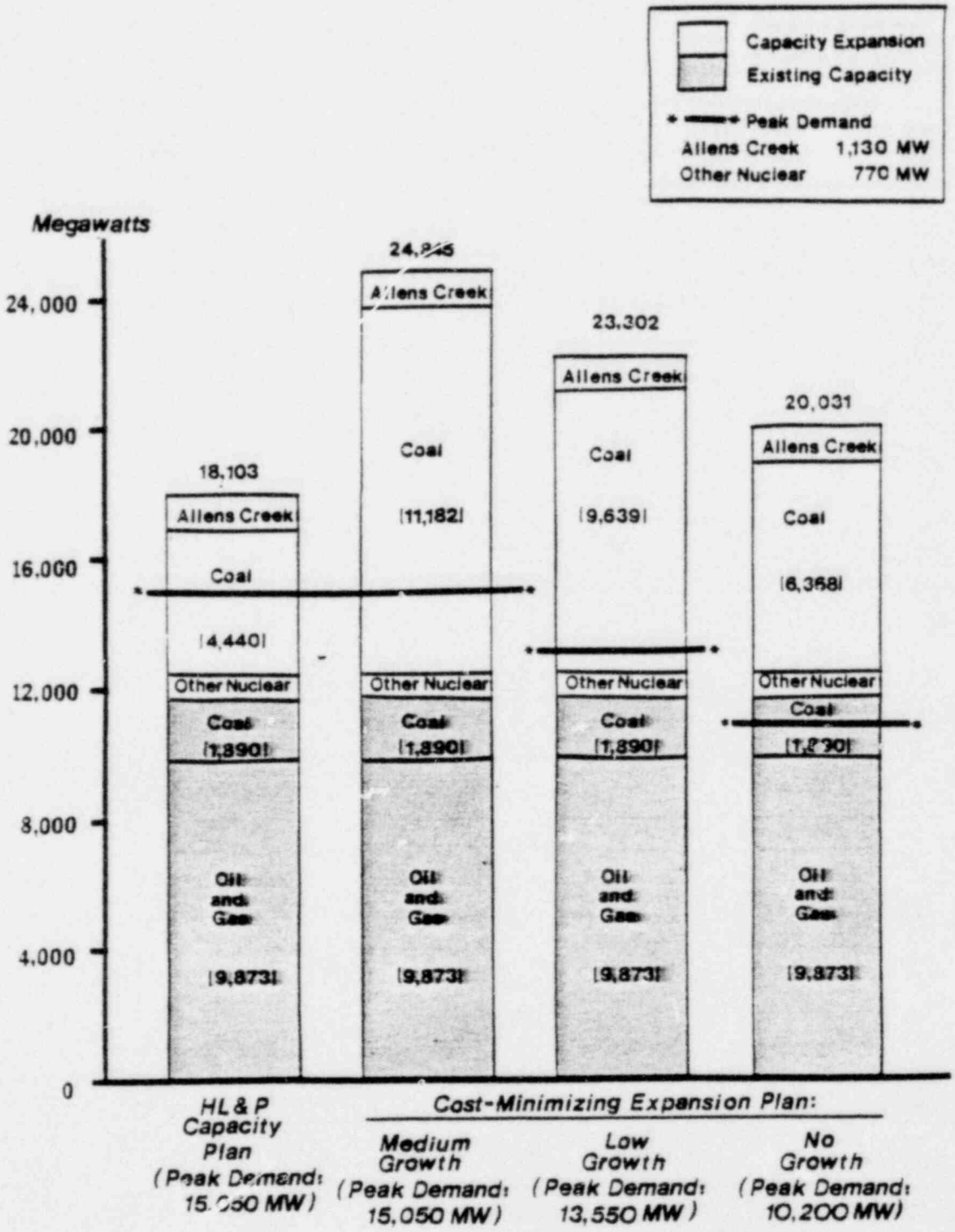
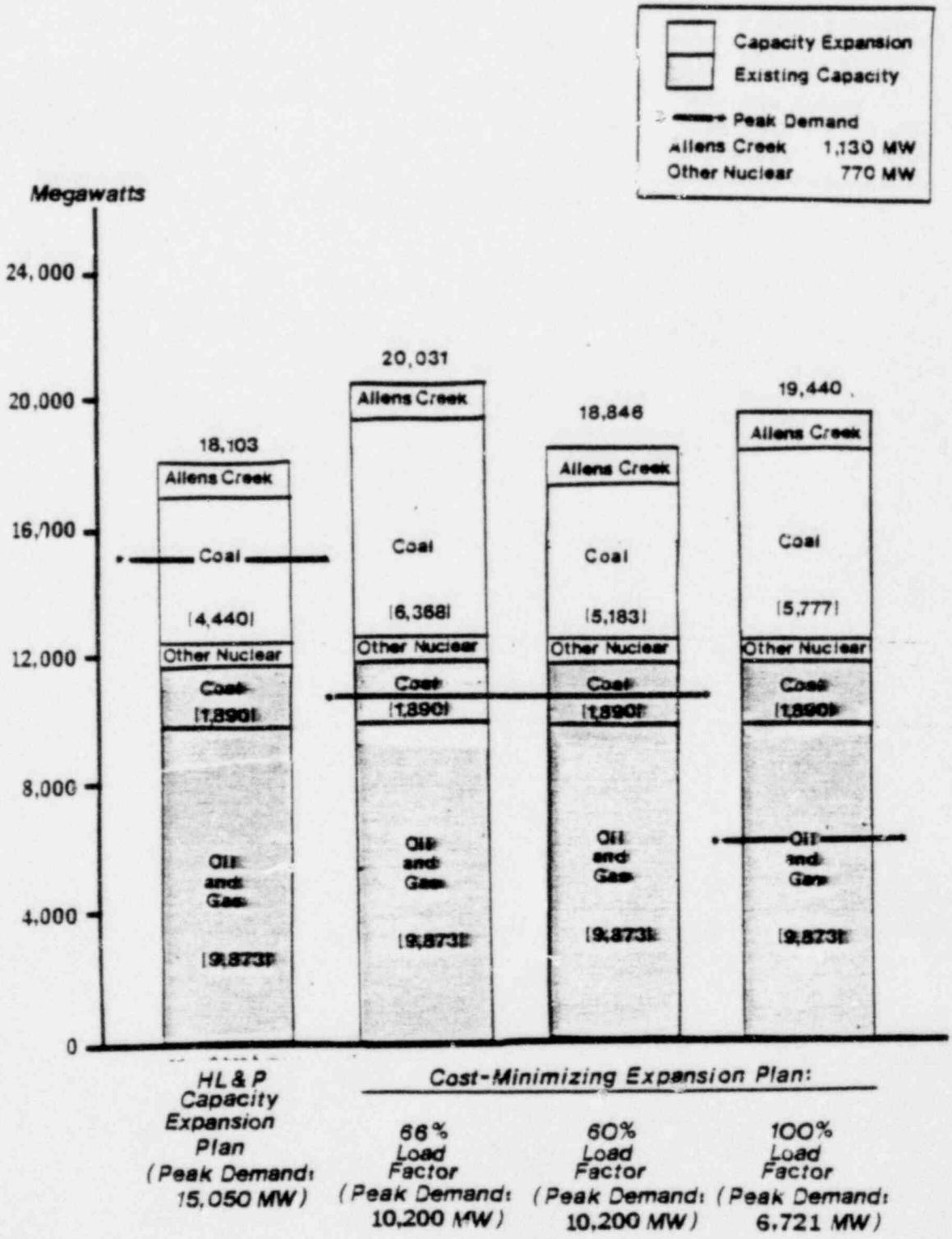


Figure 9

Capacity Expansion Plans For HL&P
Under No Growth And Alternative Load Factor Assumptions



REGRESSIONS RELATING CAPITAL COSTS FOR NUCLEAR AND COAL PLANTS TO SELECTED DETERMINANTS [1]

Variable	Nuclear Capital Costs			Coal Capital Costs		
	Variable Mean (1)	Regression Co-efficient (2)	t-Statistic [2] (3)	Variable Mean (4)	Regression Co-efficient (5)	t-Statistic [2] (6)
Constant	1.0000	6.2601	-	1.0000	5.1914	-
Ln of Size in MW [3]	6.7100	-0.1957	-1.6817	6.0967	-0.1142	-4.1529
Ln of Wage Rate[4]	2.3522	0.5087	2.5970	2.3591	0.5908	4.8079
First Unit Indicator [5]	0.4000	0.0776	1.2523	0.2618	0.2417	8.2938
Subsequent Unit Indicator[6]	0.3400	-0.1702	-2.5547			
Cooling Tower Indicator [7]	0.4000	0.0646	1.3568			
Ln of Licensing Time[8]	2.7118	0.2744	2.2362			
Ln of AE Experience [9]	1.7966	-0.0907	-4.4220			
Sequence Group 1[10]	0.1000	-0.8342	-5.4887			
Sequence Group 2[10]	0.1000	-0.6304	-3.9904			
Sequence Group 3[10]	0.2000	-0.4543	-3.5348			
Sequence Group 4[10]	0.3000	-0.3823	-3.3443			
Sequence Group 5[10]	0.2000	-0.1781	-1.8994			
Scrubber Indicator [11]				0.0901	0.1157	2.2927
Operating Date Indicator 1[12]				0.2704	-0.2274	-6.1384
Operating Date Indicator 2[13]				0.2446	-0.1296	-3.6767
Operating Date Indicator 3[14]				0.2060	0.2020	4.7783
Northeast Indicator [15]	0.3200	0.2184	4.3113			
Mountain/Pacific Indicator[15]				0.0987	0.1752	3.9376
Southwest Indicator[15]				0.0429	-0.3124	-4.3497
Number of Observations		50			233	
R-Squared		0.8981			0.6097	
Standard Error		0.1363			0.1904	

REGRESSIONS RELATING CAPITAL COSTS FOR NUCLEAR AND COAL PLANTS TO SELECTED DETERMINANTS

SOURCES AND NOTES

[1] The dependent variable in the regression is the natural log of capital cost per kilowatt. Actual costs have been adjusted to reflect the costs of constructing the plants at labor and materials costs prevailing in 1979 with no allowance for funds used during construction. Results are based on units completed through 1978.

[2] A t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 1.96 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.64 or higher indicates significance at the 10 percent level.

[3] For nuclear units, size reflects the net design electric rating as reported to the NRC at the time the unit received its operating permit. For coal units, data reflecting the Gross Generator Nameplate Rating as reported to the FPC was multiplied by 0.9 to produce a net rating.

[4] The regional wage rate is average wages plus employer contributions to funds, for all building trades in 1976, expressed in dollars per hour for the Bureau of Labor Statistics region in which the plant is located. The source is U.S. Bureau of Labor Statistics, Union Wages and Hours: Building Trades, July 1, 1976, Table 12, Bulletin 1972.

[5] The indicator equals 1 if the unit is the first unit of a series built at a site and 0 otherwise.

[6] The indicator equals 1 if the unit is a subsequent unit built at a site and 0 otherwise.

[7] The indicator equals 1 if the unit has a cooling tower and 0 otherwise.

[8] Licensing time is the number of months from date of application for construction permit to date of receipt of construction permit.

[9] AE experience is the number of reactors built or under construction by the architect-engineer at the time the unit received its construction permit.

[10] The units in the sample were arranged chronologically by date of construction permit. Units were then grouped chronologically to reflect major shifts in cost occuring over time. Sequence Group 1 includes the first five units of the sample: Sequence Group 2 includes the next five units of the sample; Sequence Group 3 includes the next 10 units; Sequence Group 4 includes the next 15 units; and Sequence Group 5 includes the next 10 units. The last five units in the sample represent a reference group.

[11] The indicator equals 1 if the unit has a scrubber and 0 otherwise.

[12] The indicator equals 1 if the unit began commercial operation between 1965 and 1968 and 0 otherwise.

[13] The indicator equals 1 if the unit began commercial operation between 1969 and 1971 and 0 otherwise. Units completed from 1972 to 1975 constitute a reference group.

[14] The indicator equals 1 if the unit began commercial operation between 1976 and 1978 and 0 otherwise.

[15] These indicator variables equal 1 if the plant is in the given region of the country and 0 if it is not in that region. See Table 12, for the definitions of the regions used. All other regions constitute a reference group.

ESTIMATED CAPITAL COSTS FOR ALLENS CREEK AND COAL ALTERNATIVES

	Allens Creek (1)	Subbituminous Plant (2)	Lignite Plant (3)
Initial Capital Cost (Net of AFDC)	(1979 $/kW)		
Plant [1]	791.93	311.88	320.96
Scrubber [4]	-	81.65	94.00
ESP [3]	-	45.67	27.65
Total Generating Plant	791.93	439.20	442.61
1990 Completed Cost Adjusted for Transmission Capital Costs	(Current $/kW)		
Generating Plant [4]	1794.99	959.58	967.03
Transmission [5]	59.98	59.98	134.85
Total	1854.97	1019.56	1101.88
1990 Completed Cost Adjusted For Transmission Capital Costs and Transmission Losses:			
Medium [6]	1854.97	1019.56	1107.05
Low [7]	1440.17	761.52	826.87
High [7]	2389.22	1365.02	1482.16

ESTIMATED CAPITAL COSTS FOR ALLENS CREEK AND COAL ALTERNATIVES

SOURCES AND NOTES

[1]Based on capital cost regressions in Table 1. For Allens Creek, the following assumptions were made: Size = 1,130 MW; Wage = $9.06; Licensing time = 27 months; AE experience = 13. For the subbituminous and lignite plants, costs were assumed to be 1.03 and 1.06 times the costs based on the regression to reflect differences in heat content between bituminous and subbituminous or lignite fuels. For the coal alternatives, we assumed that two 600-MW units would be constructed in the Southwest region.

[2]Based on the following equation:

$$[113.90 + 5.75PR - 92.45FR]\, RW^{.5908}\ RS^{-.1142}$$

where:

RW = ratio of regional wage to national wage;
RS = unit size relative to 600 MW;
PR = pounds of sulfur removed per MMBtu;
FR = ratio of outlet sulfur to inlet sulfur.

[3]Particulate costs were derived from Stearns-Rogers Incorporated, "Economic Evaluation of Fabric Filtration Versus Electrostatic Precipitation for Ultra-high Particulate Collection Efficiency," June 1978.

[4]Completed capital costs were calculated by adding escalation and interest to initial capital costs. Estimates assume 8.5 percent annual escalation from mid-1979 through 1986 and 7.5 percent escalation thereafter. Interest during construction is assumed to be 7.5 percent per year. Construction time is 7.0 years for coal and 7.5 years for nuclear.

[5]Estimates provided by J. Greenwaite of H.L&P, May 1979.

[6]Lignite costs were divided by .9953 to adjust for additional transmission losses.

[7]Derived by increasing and decreasing the logarithm of medium costs by 1.28 standard errors. This reflects an 80 percent confidence band around the medium value. To reflect the uncertainties in projecting future costs, the standard errors of regression equations excluding the date variable were used. Nuclear estimates assume a standard error of 0.1977 and coal estimates assume a standard error of 0.2280.

REGRESSIONS RELATING OPERATING AND MAINTENANCE COSTS FOR NUCLEAR AND COAL PLANTS TO SELECTED DETERMINANTS[1]

Variable	Nuclear O&M Costs			Coal O&M Costs		
	Variable Mean (1)	Regression Co-efficient (2)	t-Statistic[2] (3)	Variable Mean (4)	Regression Co-efficient (5)	t-Statistic[2] (6)
Constant	1.000	-1.4339	-2.08	1.000	-6.1335	13.00
Ln (Unit Size)[3]	1.526	0.3591	6.97	1.476	1.8169	14.34
1/(Unit Size)[3]				0.269	2.0000	5.21
Ln (Number of Units)	0.164	0.6106	5.62	0.502	0.9210	17.14
Regional Wage Index[4]	1.052	1.3957	4.51	1.020	1.8678	4.76
Wage Escalation Index[5]	1.807	1.7487	13.93	1.636	1.1842	18.71
Northeastern Region Indicator[6]	0.470	0.3969	6.31	0.230	0.1223	1.93
Southern Region Indicator[6]	0.113	0.2662	2.56	0.376	0.0912	1.15
Western Region Indicator[6]				0.122	0.1798	2.18
Ln (Vintage)[7]	2.078	-0.1381	-2.16	1.339	-0.2538	-6.16
Ln (Age +1)[8]	1.554	-0.8211	-3.34			
1/(Age +1)[8]	0.248	-2.9540	-3.51			
Number of Observations		168			335	
R-Squared		0.8743			0.9026	
Standard Error		0.3144			0.3303	

REGRESSIONS RELATING OPERATING AND MAINTENANCE COSTS FOR NUCLEAR AND COAL PLANTS TO SELECTED DETERMINANTS

SOURCES AND NOTES

[1]The dependent variable is the natural log of cost in millions of current dollars. With the exception of the wage indices, the 1965-1974 data are from Federal Power Commission (now Federal Energy Regulatory Commission), Steam-Electric Plant Construction and Annual Production Expenses and the 1975-1977 data are from Schedule 432 of Federal Power Commission Form One, "Annual Report of Privately Owned Electric Utilities, Classes A and B."

[2]A t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 1.96 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.64 or higher indicates significance at the 10 percent level.

[3]Unit size is the gross size of the unit in hundreds of MW.

[4]Ratio of 1969 median earnings for electric and gas utilities employees for the SMSA nearest the plant to the median value of this variable for the U.S.. Source is U.S. Bureau of the Census, Census of the Population: 1970, Vol. 1, Table 188.

[5]Wage index for each year with the 1965 as the base to measure inflation. Source is U.S. Bureau of Labor Statistics, Employment and Earnings, U.S., 1909-78, Bulletin 1312-11, pp. 730-731.

[6]These indicator variables equal 1 if the plant is in the given region of the country and 0 if it is not in that region. See Table 12 for the definitions of the regions used. All other regions constitute a reference group.

[7]Vintage equals the year the plant came on line minus 1963 for coal and minus 1959 for nuclear (so that the earliest plant year has a value of 1).

[8]Age is the average age of the plant, calculated as the average of the ages of the individual units weighted by unit size.

OPERATION AND MAINTENANCE COSTS FOR ALLENS CREEK AND COAL ALTERNATIVES

	Low (1)	Medium (2)	High (3)
		($/KW)	
FIXED O&M COSTS			
Plant O&M Costs (1979 $) [1]			
Allens Creek	8.44	12.63	18.87
Subbituminous Plant	4.25	6.48	9.90
Lignite Plant	4.25	6.48	9.90
Plant O&M Costs (1990 $) [2]			
Allens Creek	16.73	25.03	37.42
Subbituminous Plant	8.42	12.85	19.63
Lignite Plant	8.42	12.85	19.63
Transmission O&M Costs (1990 $) [3]			
Allens Creek	1.13	1.69	2.53
Subbituminous Plant	1.11	1.69	2.58
Lignite Plant	2.49	3.79	5.79
O&M Costs Adjusted for Transmission O&M (1990 $)			
Allens Creek	17.86	26.72	39.95
Subbituminous Plant	9.53	14.54	22.21
Lignite Plant	10.91	16.64	25.42
Levelized O&M Cost Adjusted for Transmission Losses (Current $) [4]			
Allens Creek	30.66	45.87	68.59
Subbituminous Plant	16.36	24.96	38.13
Lignite Plant	18.82	28.70	43.84
SCRUBBER O&M COSTS		(mills/kWh)	
1979 Mills/kWh [5]			
Subbituminous Plant		1.82	
Lignite Plant		2.37	
Levelized Current Mills/kWh Adjusted for Transmission Losses [4]			
Subbituminous Plant		5.79	
Lignite Plant		7.59	

OPERATION AND MAINTENANCE COSTS FOR ALLENS CREEK AND COAL ALTERNATIVES

SOURCES AND NOTES

[1] Medium costs were calculated from the regression equations documented in Table 3. For Allens Creek, costs reflect a single unit 1130 MW plant; the coal plants consist of two 600-MW units. The regional wage index equals .9597, the wage escalation index equals 2.21 and the plants are in the South. In addition to the regession forecast, nuclear costs include a $.40/kW premium for nuclear insurance. Vintage eguals 18 for Allens Creek and 14 for coal. O&M costs reflect the levelized impact of increases in real costs through year 10 and constant costs thereafter. Low and high costs are calculated as ±1.28 standard errors from the mean. This reflects an 80 percent confidence band around the medium value.

[2] 1979 dollar costs are escalated at 6.28 percent annually from 1979 through 1986 and 5.5 percent annually thereafter.

[3] Medium costs are based on information provided by J. Greenwaite, HL&P. Low and high costs assume the ratio of transmission to plant costs is the same as for the medium case.

[4] 1990 dollar costs are levelized over the 33-year operating life of the plant assuming an inflation rate of 5.5 percent and a discount rate of 11.05 percent. Levelized plant costs for lignite are divided by .9953 to adjust for additional transmission losses.

[5] Based on the equation:

Scrubber O&M = (1 + Energy Penalty) (Lime Cost + Ash Disposal + Other O&M)

where:

$$\text{Energy Penalty} = [.0317 - .0310 * \frac{OS}{IS}];$$

$$\text{Lime Cost} = [1.01 * .0005 * LP * (IS-OS)]\ HR * 10^{-3} * ESC\ 79;$$

$$\text{Other O\&M} = [.1290 + .0011 * IS + .0112 * OS - .1172 * \frac{OS}{IS}]\ HR * 10^{-3} * ESC\ 79;$$

$$\text{Ash Disposal} = [.0005 * AC * AP * .2] * HR * 10^{-3} * ESC\ 79;$$

OS = Outlet sulfur = .445 and .4624 lbs. SO_2/MMBtu for subbituminous and lignite respectively;
IS = Inlet sulfur = 1.4952 and 2.2348 lbs. SO_2/MMBtu for subbituminous and lignite respectively;
LP = Lime price = $40/Ton;
HR = Heat rate = 10,000 Btu/kWh;
AC = Ash content = 8.14 and 12.78 lbs./MMBtu for subbituminous and lignite respectively;
AP = Ash disposal price = $4/Ton;
ESC79 = factor to convert mid-1977 to mid-1979 dollars = 1.1517.

REGRESSIONS RELATING NUCLEAR CAPACITY FACTOR AND COAL EQUIVALENT AVAILABILITY FACTOR TO SELECTED DETERMINANTS

Variable	Nuclear Capacity Factor[1]			Coal Equivalent Availability Factor[2]		
	Variable Mean (1)	Regression Co-efficient (2)	t-Statistic[3] (3)	Variable Mean (4)	Regression Co-efficient (5)	t-Statistic[3] (6)
Constant	1.0000	-161.7059	-	1.0000	30.92202	-
1/Ln (1+Vintage)[4]	0.3815	617.2019	2.3363			
Size Indicator 1[5]	0.3786	211.1855	1.9767			
Size Indicator 2[6]	0.3107	245.5147	2.0380			
Size Indicator 3[7]	0.1553	341.3599	1.3842			
Size 1/Ln (1+Vintage)	0.1505	-574.0762	-2.0496			
Size 2/Ln (1+Vintage)	0.1166	-669.7551	-2.1010			
Size 3/Ln (1+Vintage)	0.0556	-952.5255	-1.3949			
1/Log (1+Age)[8]	1.9081	-3.7548	-1.9474	1.4943	5.7776	2.3692
First Year Equivalent Availability Factor[9]				63.6315	0.3730	5.1403
Sulfur Content[10]				22.1889	-0.3865	-4.9580
1/Size[11]				0.1327	75.7579	2.0509
Number of Observations		103			270	
R-Squared		0.1064			0.1814	
Standard Error		14.0213			14.2439	

REGRESSIONS RELATING NUCLEAR CAPACITY FACTOR AND COAL EQUIVALENT AVAILABILITY FACTOR TO SELECTED DETERMINANTS

SOURCES AND NOTES

[1]The regression is based on the observed capacity factor for each year from 1961-1978 for commercial boiling water reactors completed through 1978. Initial partial years were excluded. The dependent variable is capacity factor as a percent.

[2]The regression is based on the observed equivalent availability factor on coal units over 600 MW for each year through 1977. Initial partial years and the first full year of operation were excluded. The dependent variable is equivalent availability factor as a percent.

[3]A t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 1.96 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.64 or higher indicates significance at the 10 percent level.

[4]Vintage equals the year the plant came on line less 1959, so the earliest plant has a value of 1.

[5]The indicator equals 1 if net design rating is between 600 MW and 799 MW and 0 otherwise.

[6]The indicator equals 1 if net design rating is between 800 MW and 999 MW and 0 otherwise.

[7]The indicator equals 1 if net design rating is 1,000 MW or greater and 0 otherwise.

[8]Age is the number of full operating years between the commercial operation date and the year in which the equivalent availability factor is measured. A unit's first calendar year of operation (beginning the first New Year's Day on which the unit was in commercial operation) is counted as year one.

[9]Observed equivalent availability factor for the first full year of operation.

[10]Sulfur content is expressed as percent times 10.

[11]Size is measured as hundreds of megawatts. Megawatts is the FPC nameplate rating.

LEVELIZED CAPACITY FACTORS FOR ALLENS CREEK AND COAL ALTERNATIVES

	Capacity Factor		
	Low [1]	Medium [1]	High [1]
	(Percent)		
	(1)	(2)	(3)
Allens Creek			
No Vintage Trend [2]	43	61	79
Vintage Trend Extrapolated to 1986 [3]	55	73	91
NERA Estimate	47	65	83
Coal Alternatives [4]	50	68	87

SOURCES AND NOTES

[1] Low and high values are calculated as 1.28 standard errors from the medium. This reflects an 80 percent confidence band around the medium value.

[2] Based on regression equation in Table 5, assuming vintage equals 78 and size is greater than 1000 MW.

[3] Based on regression equation in Table 5, assuming vintage equals 86 and size is greater than 1000 MW.

[4] The gross equivalent availability factor is based on regression equation in Table 5, assuming size is 600 MW and using the mean value of the regression data for the first year equivalent availability factor. The net capacity factor is estimated assuming that net capacity is 90 percent of gross capacity and that the maximum capacity factor is 90 percent of the equivalent availability factor.

FORECASTS OF URANIUM OXIDE PRICES[1]

Year	0.2 Percent Tails Assay			0.3 Percent Tails Assay		
	Low	Medium	High	Low	Medium	High
	(1979 Dollars/Pound)					
	(1)	(2)	(3)	(4)	(5)	(6)
1988	21.88	23.21	24.61	24.55	26.03	27.61
1989	23.08	24.83	26.74	25.88	27.86	29.98
1990	24.33	26.58	29.03	27.28	29.81	32.56
1991	27.00	29.93	33.19	30.03	33.29	36.91
1992	28.24	31.77	35.74	31.54	35.49	39.94
1993	29.90	34.15	38.98	33.43	38.18	43.58
1994	31.64	36.67	42.48	35.39	41.00	47.52
1995	33.43	39.31	46.23	37.42	44.00	51.74
1996	35.28	42.11	50.27	39.52	47.17	56.29
1997	37.21	45.08	54.59	41.71	50.50	61.17
1998	39.22	48.21	59.26	43.96	54.03	66.42
1999	41.29	51.51	64.25	46.31	57.77	72.05
2000	43.44	55.00	69.62	48.74	61.71	78.11
2001	41.19	52.91	67.98	47.08	60.47	77.70
2002	43.52	56.73	73.97	49.40	64.41	83.96
2003	44.82	59.30	78.46	50.88	67.31	89.07
2004	46.16	61.98	83.22	52.39	70.36	94.48
2005	46.31	63.10	86.00	52.57	71.64	97.63
2006	47.34	65.47	90.54	53.73	74.32	102.78
2007	48.22	67.68	94.97	54.74	76.82	107.82
2008	49.10	69.93	99.61	55.74	79.39	113.07
2009	49.99	72.26	104.45	56.74	82.02	118.56
2010	50.88	74.65	109.49	57.76	84.73	124.29
2011	51.51	76.68	114.14	58.46	87.04	129.57
2012	51.65	78.03	117.89	58.63	88.58	133.83
2013	52.78	80.94	124.09	59.92	91.88	140.88
2014	52.95	82.39	128.20	60.11	93.53	145.53
2015	52.65	83.13	131.27	59.77	94.37	149.02
2016	52.17	83.60	133.97	59.22	94.89	152.07
2017	51.10	83.12	135.17	58.02	94.35	153.45
2018	49.37	81.47	134.48	56.04	92.50	152.65
2019	47.41	79.40	133.01	53.81	90.14	150.99
2020	46.15	78.45	133.36	52.39	89.06	151.39
Levelized Price, 1988-2020	36.30	47.39	62.97	40.94	53.50	71.17

SOURCES AND NOTES

[1]Derived from NERA model of uranium oxide supply and demand. Demand for uranium oxide is based on forecasts in U. S. Department of Energy, Grand Junction Office, Statistical Data of the Uranium Industry, January 1, 1978.

ESTIMATED FUEL PRICES FOR ALLENS CREEK

Fuel Component	Units	Component Purchase Date[5]	Low (1)	Medium (2)	High (3)
Constant Dollar Case			(1979 $/Unit)		
Uranium Oxide - 0.2% Tails[2]	Lbs.		36.30	47.39	62.97
Uranium Oxide - 0.3% Tails[2]	Lbs.		40.94	53.50	71.17
Conversion[3]	Kg.		5.21	6.51	7.82
Enrichment[3]	SWU		97.72	143.33	260.59
Fabrication[3]	Kg.		117.27	156.36	195.44
Transportation and Disposal[3]	Kg.		143.33	277.56	364.83
Current Dollar Case[4]			(Current $/Unit)		
Uranium Oxide - 0.2% Tails	Lbs.	7/88	62.12	81.10	107.76
Uranium Oxide - 0.3% Tails	Lbs	7/88	70.06	91.56	121.80
Conversion	Kg.	7/88	8.92	11.14	13.38
Enrichment	SWU	7/89	176.43	258.78	470.49
Fabrication	Kg.	1/90	217.47	289.96	362.44
Transportation and Disposal	Kg.	7/98	418.99	723.67	1,066.48

SOURCES AND NOTES

[1]Reflects the cost of each component adjusted for the effect of any real escalation over the life of the plant. Only Uranium Oxide prices are assumed to escalate in real terms.

[2]See Table 7.

[3]Prices are from draft testimony by NUS Corporation in the Matter of Generic and Environmental Statement on Mixed Oxide Fuel. NUS prices assume no recycling will take place. NUS estimates in 1975 dollars were escalated at the general rate of inflation to convert them into 1979 dollar estimates.

[4]Mid-1979 dollar prices were escalated to date at which spent at 6.28 percent annually through 1986 and 5.5 percent annually thereafter. In calculating levelized nuclear fuel prices, these component costs were adjusted for the effect of inflation over the life of the plant.

[5]Component purchase dates are based on a January 1990 start date.

ESTIMATED FUEL PRICES FOR THE COAL ALTERNATIVES TO ALLENS CREEK

		Subbituminous			Lignite		
		Low (1)	Medium (2)	High (3)	Low (4)	Medium (5)	High (6)
F.O.B. Coal Prices in 1979 $/Ton							
1990:	Texas [1]				11.32	11.92	13.26
	New Mexico[1]	11.77	11.77	11.77			
	Western Wyoming[1]	8.13	8.13	8.13			
	Average	9.95	9.95	9.95			
2000:	Texas [1]				15.99	20.19	23.96
	New Mexico[1]	13.00	20.57	32.58			
	Western Wyoming[1]	8.98	12.35	17.23			
	Average	10.99	16.46	24.90			
Levelized F.O.B. Cost [2]			12.54	17.44	25.26	17.37	22.01
Levelized Transport Costs in 1979 $/Ton [3]							
New Mexico		18.06	18.06	18.06			
Western Wyoming		22.49	22.49	22.49			
Average		20.27	20.27	20.27			
Levelized Delivered Fuel Cost							
1979 $/Ton [4]		32.81	37.71	45.53	17.37	22.01	28.65
1979 Mills/kWh [5]		20.61	23.69	28.60	14.52	18.38	23.92
Current Mills/kWh [5]		65.62	75.43	91.07	46.22	58.50	76.14

ESTIMATED FUEL PRICES FOR THE COAL ALTERNATIVES TO ALLENS CREEK

SOURCES AND NOTES

[1]Reflects price forecasts in 1990 and 2000 from the NERA Electricity Supply Optimization Model.

[2]Subbituminous coal prices reflect an average of New Mexico and Western Wyoming prices. For the years between 1990 and 2000 prices are estimated based on the growth rates for the decade. After 2000, annual prices for subbituminous coal assume a real growth rate of 1.5 percent per year; annual prices for lignite after 2000 assume a real growth rate of 1.5 percent in the low case, 2.0 percent in the medium case and 2.5 percent in the high case. Levelized prices in 1979 dollars are estimated assuming a discount rate of 5.05 percent and a 33-year plant life.

[3]Derived from the equation:

$$\$/\text{Ton} = 2.536 + 0.01348 * \text{miles},$$

assuming that New Mexico coal must be transported 1,152 miles, Western Wyoming coal must be transported 1,479 miles, and there is no real escalation in transport costs.

[4]The sum of transport cost and costs F.O.B. the mine.

[5]1979 mills/kWh = (1979 $/Ton * Heat Rate * 0.5)/Heat Content. Heat content is 8,139 Btu/Lb. for subbituminous and 6,170 Btu/Lb. for lignite coal. Plant heat rates are 10,220 for subbituminous and 10,303 for lignite and reflect scrubber energy penalties of 2.0 percent for subbituminous and 2.55 percent for lignite. For the lignite plant, costs are further adjusted for transmission losses by dividing costs by 0.9953. Levelized costs in current dollars reflect adjustments for inflation of 6.28 percent annually from 1979 to 1986 and 5.5 percent thereafter. Adjustment includes levelized effect of inflation over the life of the plant at a discount rate of 11.05 percent.

FINANCIAL ASSUMPTIONS USED IN PERFORMING COAL/NUCLEAR COST COMPARISONS

	Share	Yield
	(Percent)	
	(1)	(2)
Capital Structure		
Long Term Debt	50.0	8.75
Preferred Stock	10.0	8.75
Common Stock	40.0	14.50
Discount Rate		11.05
AFDC		
Post 1978		7.50
Tax Rates		
Federal Income Tax		46.00
Property Tax		
Through 1982		1.35
Post 1982		1.38
Tax Treatment		
Book Life		33 Years
Tax Life:		
Coal		23 Years
Nuclear		16 Years
Method of Depreciation	double declining balance for 2 years, sum of years' digits for remaining life, normalized	
Investment Tax Credit:		
Rate		10.00
Treatment		flow through
Proportion of Plants Depreciable for Tax Purposes		
Coal		0.83
Nuclear		0.82

Escalation Rates	Through 1986	Post 1986
	(Percent)	
	(1)	(2)
General	6.5	5.5
Capital	8.5	7.5
O&M	7.5	5.5

DERIVATION OF NUCLEAR FIXED CHARGE RATE ADJUSTED FOR DECONTAMINATION AND DECOMMISSIONING COSTS

Completed Capital Cost Excluding Transmission ($/KW)	1,794.99
Decontamination Cost ($/KW)[1]	
Year 15	111.83
Year 25	191.02
Decommissioning Cost ($/KW)[2]	
Year 33	922.86
Levelized Annual Charge ($/KW)[3]	
Decontamination	4.24
Decommissioning	3.31
Levelized Annual Fixed Charge Rate (Percent)	
Unadjusted	17.06
Adjusted for decommissioning	17.24
Adjusted for decommissioning and decontamination	17.48

SOURCES AND NOTES

[1] Based on decontamination costs of $24/KW in 1977 dollars occurring once in 15th year and once in 25th year of operation from a study by Sargent & Lundy Engineers, Nuclear Versus Coal Economic Study, Draft Report prepared for Arizona Public Service Company, Report SL - 3725, April 1979. Exhibit III - 21. Costs were escalated to the year of expenditure at the following general rates of escalation: 1978, 7.4 percent; 1979 through 1986, 6.5 percent annually; and post-1986, 5.5 percent annually.

[2] Decomissioning costs were estimated at 10 percent of costs at start of construction and escalated to the year of expenditure at the general rates of escalation in footnote 1. This estimate reflects a conservative interpretation of results developed by Atomic Industrial Forum, National Environmental Studies Project, An Engineering Evaluation of Nuclear Power Reactor Decommissioning Alternatives, (AIF/NESP-009-009SR), Washington, D.C., 1976.

[3] Based on discount rate of 11.05 percent.

DEFINITIONS OF REGIONS USED IN REGRESSION ANALYSES

TABLE 1 REGIONS

Northeast:

Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, Washington, D.C.

Mountain/Pacific:

Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Southwest:

Arkansas, Louisiana, Oklahoma, Texas

TABLE 3 REGIONS

Northeast:

Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont

South:

Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia

West:

Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming