WHAT THE PARSONS STUDY REALLY SAYS ABOUT NUCLEAR POWER ECONOMICS: THE GRAND CANYON CONTROVERSY, ROUND ?

William E. Hoehn

March 1967

P-3548

WHAT THE PARSONS STUDY REALLY SAYS ABOUT NUCLEAR POWER ECONOMICS: THE GRAND CANYON CONTROVERSY, ROUND ?

William E. Hoehn*

The RAND Corporation, Santa Monica, California

The Ralph M. Parsons Co. was retained by the Arizona Interstate Stream Commission to "show the effect of substituting nuclear-fueled power generation facilities for proposed hydroelectric power generating plants at Hualapai Dam and Marble Canyon Dam on the Basin Account Consolidated Payout Schedule."[1] The principal conclusions of the Parsons study are:

> (1) Comparing nuclear alternatives with the hydroelectric plants on a peaking basis shows that the nuclear plants themselves will never pay out since the annual interest payments are greater than the net revenues as demonstrated in the Consolidated Payout Schedules herein.[2]
> (2) This study also compares the funds accumulation from a base-loaded nuclear plant with those accumulated from the hydroelectric plants. While this comparison accrues the most funds from the various nuclear alternatives considered in this study, the funds accumulated are substantially less than those accumulated from the hydroelectric plants.[3]

---

*Any views expressed in this paper are those of the author. They should not be interpreted as reflecting the views of The RAND Corporation or the official opinion or policy of any of its governmental or private research sponsors. Papers are reproduced by The RAND Corporation as a courtesy to members of its staff.

[1] "Economics Analysis, Nuclear Versus Hydroelectric Power Generation, Colorado River Basin Project, Interstate Stream Commission, State of Arizona," The Ralph M. Parsons Co., Number 3874-1, July 20, 1966, p.11; hereafter cited and referred to as the "Parsons Study."

[2] *Ibid*, p.12.

[3] *Ibid*, p.12.

(3) Even at the federal financing interest rate of 3.222%, the baseloaded nuclear power plants could not repay their costs if it were not for the outside contributions to the combined fund of revenues from Hoover, Parker, and Davis Dams in later years of the analysis.

(4) Evaluating only the economics of nuclear energy production at the plants -- by neglecting all transmission costs -- the four nuclear plants, baseloaded, could not repay their costs if the aggregate fixed charge rate (including depreciation) were in excess of 6.1% per annum.

These latter implications are so astoundingly contrary to the overwhelming preponderance of evidence from the real world that the credibility of the related Parsons Study conclusions quoted in (1) and (2) above seems doubtful. With regard to conclusion (3), the Bureau of Reclamation (an outspoken proponent of the dams) has admitted:

> There is little doubt, from a theoretical point of view, that a nuclear plant could be selected of a certain size and operational pattern to contribute as much or more to the Development Fund as would the Marble Canyon hydroplant.[4]

In the recent announcement that the Administration no longer favors construction of either of the dams as a feature of the Central Arizona Project, but favors the purchase of energy from thermal plants to be built by WEST Associates, Secretary of the Interior Stuart L. Udall described the new plan as "a victory for common sense."[5]

---

[4] U.S. Congress, House Committee on Interior and Insular Affairs, Lower Colorado River Basin Project, Hearings before Sub-Committee, Part II, 89th Congress, 2nd Session, May 13, 1966, p. 1520.

[5] Quoted in the Los Angeles Times (Preview Edition), Thursday, February 2, 1967, p. 2.

With respect to conclusion (4), in the last two years investor-owned (private) utilities, with overall fixed charge rates ranging from 10% - 14% per annum, or roughly double the break-even figure of the Parsons Study, have placed orders for more than 20,000,000 kilowatts of new nuclear generating capacity. In fact, in 1966 more nuclear capacity than fossil-fueled capacity was ordered. If the implicit conclusion (4) of the Parsons Study were true, this would mean that these utilities through their independent evaluations of nuclear power economics, have committed themselves to an aggregate investment of well over two billion dollars that cannot be repaid even through baseloaded operation. If this were indeed the case, this would represent a miscalculation unparalleled in the history of private sector investment decisions, and one that would rank with only the most remarkable of past federal reclamation project miscalculations.

To verify that conclusion (3) is implicit in the Parsons Study, one need only refer to either Table S or Table W of the Parsons Study. Column 5 of those tables shows the unpaid balance of the (interest-bearing) investment in the plants by years. In each of the first 18 years, the unpaid balance increases demonstrating that annual revenues are less than annual costs (including, of course, interest on invested capital).[6] Only with Year 19 and following years, when revenues from

---

[6] In the Parsons Study, annual costs <u>except for interest charges</u> are developed for all alternatives. These interest-less "costs" are then deducted from gross nuclear revenues on one set of charts (Tables H - O of the Parsons Study) in which revenues from Hoover, Parker, and Davis Dams are commingled with nuclear gross revenues. The resulting series for each alternative (which bear the label "Consolidated Net Annual Revenues") are then carried over to another set of eight charts (Tables P - X of the Parsons Study) of "Consolidated Payout Schedules," where, under the Power section in the "Interest Bearing Investment" column, interest payments are finally applied. That is, under the Parsons Study procedures, revenues are first used to defray annual operating and maintenance costs; remaining revenues are used to defray the depreciation account (the Replacement Fund);

Hoover, Parker, and Davis are incorporated into Column 1 of those tables (Net Operating Revenue), does the investment begin to decline.[7]

Somewhat more effort is required to verify conclusion (4). The Parsons Study evaluates no less than eight alternative cases -- three plants in Los Angeles and one in Arizona versus four plants in Los Angeles, both baseloaded and peak-loaded, and all at both 3.222% interest and 4.5% interest -- and the mass of data and proliferation of tables is more than sufficient to stun the casual reader. Accordingly, conclusion (4) will be verified herein only for the case of three plants at Los Angeles and one in Arizona, which most nearly corresponds to the proposed distribution of energy. Tables 1 and 2 reproduce, respectively, relevant portions of the Parsons Study capital cost and annual cost tables for this alternative location.[8]

The exclusion of transmission costs assumed in conclusion (4) permits us to discard Item 9 of Table 1, reducing investment in plant and equipment to the $397 million of Line 8, and to discard Line 7 of Table 2, reducing annual costs before replacement and interest on investment from $30.877 million to $28.904 million. At the assumed overall fixed charge rate of 6.10%, the annual replacement (a form of depreciation accounting) and interest charges on the $397 million investment would be $24.217 million. Then total annual

---

any remaining revenues are then applied first to payment of annual interest charges and then to reducing the unpaid balance of the investment account. Thus an <u>increasing</u> unpaid investment account indicates that revenues are insufficient to meet even the total annual interest charges.

[7]Tables J and N, in which Net Operating Revenues for Tables S and W, respectively, are derived, show in Column 9 (Hoover, Parker, Davis Net Revenues) that Year 19 is indeed the first year in which outside revenue is added.

[8]Parsons Study, *op. cit.*, Tables C and G.

costs are \$53.121 million.[9] Annual revenues in the Parsons Study fluctuate slightly from year to year; however, the sum of the Gross Nuclear Revenues over the 75-year period of analysis is \$3,983,239,000,[10] so that the average annual revenue may be taken to be \$53.110 million. Thus, at a 6.1% fixed charge rate with no allowance for transmission costs, taxes or other private-utility costs, the four baseloaded nuclear plants incur losses of \$11,000 per year.[11] Moreover, at a typical private-utility fixed charge rate of 12% per annum, the deficit for the four units would be in excess of \$23.4 million per year under the Parsons Study cost and revenue assumptions, or an annual loss of \$5.95 million per nuclear plant! Thus, if the Parsons Study analysis is to be accepted, it follows that those private utilities that have ordered nuclear plants have not just made a minor error, but have indeed made a colossal miscalculation.

---

[9] The sum of \$28.904 million operating and \$24.217 million capital costs.

[10] Parsons Study, op. cit., Table N, Column 8, p. 89.

[11] This is, admittedly, a simplified analysis. The Parsons Study uses a combination interest charge and sinking fund rate, with a 100-year period on the items in Lines 1, 4, 6, and 7 of Table 1, 50-year on transmission (Line 9) and 100-year on land and site development (Lines 2 and 3); under this procedure, the break-even interest rate is 4.58%, with fixed charge rates (including sinking fund) of 6.197 for 30-year items and 4.633 on land. This, of course, closely approximates the overall 6.1% fixed charge rate used above.

Table 1

PARSONS STUDY CAPITAL COST ASSUMPTIONS

Three Units in L.A. and One in Arizona

Line	Item	Cost in $ Millions
1.	Equipment and facilities	270.90
2.	Land and land rights	7.60
3.	Site development	16.70
4.	Indirect capital	14.60
5.	Subtotal, lines 1-4	309.80
6.	Interest during construction	9.90
7.	Working capital	77.30
8.	Subtotal	397.00
9.	Transmission facilities	141.00
10.	TOTAL	538.00

Source: Parsons Study, *op. cit*., Table C, p. 52.

Table 2

PARSONS STUDY ANNUAL COSTS FOR BASELOADED PLANTS

Three Units in L.A. and One Unit in Arizona

Line	Item	Cost in $ Millions
1.	Operating and maintenance labor	1.665
2.	General and administration expenses	0.371
3.	Maintenance materials and supplies	0.270
4.	Nuclear insurance	2.261
5.	Nuclear fuel	23.687
6.	Cooling water	0.650
7.	Transmission maintenance	1.973
8.	Total annual cost before replacement	30.877
9.	Replacement fund (at 3.222%)	8.620
10.	Total annual cost before interest on investment	39.497

Source: Parsons Study, *op. cit.*, Table G, p. 61.

Now that it has been shown that the Parsons Study analysis implies certain unacceptable conclusions, it may be of interest to identify some of the more important points at which various estimates and assumptions have contributed to the unfortunate disparity between the Parsons Study and real-world nuclear power economics. We consider first those aspects dealing with nuclear power costs and revenues in the general case, and then some aspects of the particular comparison of nuclear and hydropower for the Development Fund.

NUCLEAR POWER COST ESTIMATION

Under this heading we will briefly consider the following items -- powerplant selection and costs, land costs, and interest during construction.

Powerplant Selection and Costs. The nuclear powerplant design assumed in the Parsons Study is the dual-cycle reactor of the Dresden I type. Unfortunately, the dual-cycle reactor type assumed in the study is no longer offered by any of the major U.S. reactor vendors, and was last offered as an alternative to the Oyster Creek and Nine Mile Point plants in 1963. In both cases, the utilities selected the single-cycle version because it entails lower initial investment and greater efficiency, and because developments such as variable flow recirculating pumps proved to be a more flexible method of handling load changes. In the Oyster Creek analysis,[12] the contract price of the single-cycle reactor was $1.5 million less than the dual-cycle. Since the Oyster Creek reactor is roughly the size of each of the four reactors assumed in the Parsons Study, capital costs for plant and equipment would appear to be overstated by some $6 million plus overheads, which

[12] Report on Economic Analysis for Oyster Creek Nuclear Generating Station; Jersey Central Power and Light Co., February 17, 1964; also reprinted in AEC Authorizing Legislation - 1965, Part 2, Appendix 4.

represents an annual cost reduction of some $330,000 at the 3.222% interest rate.

The Parsons Study also assumes a net capacity of 2450 electric megawatts (MWe) from the 2600 MWe gross capacity of the four units. For single-cycle plants of 650 MWe gross using ocean water cooling, auxiliary power requirements should not exceed 20 MWe, and for inland plants, because of cooling tower fan power requirements, auxiliary power should be about 30 MWe, so that the net rating of the three plants in Los Angeles and one in Arizona should be about 2510 MWe. This is somewhat academic, as the Parsons Study inadvertently used the gross power rating rather than net power in computing the annual nuclear generation of 18.22 billion kilowatt-hours (kwh) per year at base-load (80% load factor), which is the figure used throughout. This would result in adjusted annual energy production of 17.59 billion kwh.

In the absence of more detailed cost estimates it is not possible to comment on the accuracy or acceptability of the various estimates; the overall level of nuclear capital costs appears reasonably representative of costs as of the publication date of the study.

Land Costs. The Parsons Study based its estimate of land costs on a Bechtel study of alternative sites for the proposed power and desalting plants. Land costs are assumed to be $25,000 per acre for "ocean frontage" and $10,000 per acre for "land to the rear of the ocean frontage."[13] Total land costs for the case of all four plants in Los Angeles is given as $8.25 million for 400 acres.[14] The only purchase consistent with these figures is 283 1/3 acres of ocean frontage and 116 2/3 acres of land to the rear.

---

[13] Parsons Study, *op. cit.*, p. 53.

[14] *Ibid.*, p. 53 and Table B.

Since plants would be placed along the shoreline with the exclusion area to either side and inland, these oceanfront acres appear to be acquired as long thin strips.[15]

Quite as remarkable is the assumption that land costs fall from \$8.25 million to \$7.6 million for the case of three plants in Los Angeles and one in Arizona. Since the Los Angeles plants would be located immediately adjacent to each other, land savings for the deletion of a fourth unit at an oceanfront site would be negligible, while costs for acreage in Arizona would be added.

The proposed site is surely among the most expensive that could have been selected; alternatives not discussed in the Parsons Study would include avoiding the purchase of oceanfront land by locating slightly inland from the beach (as at Malibu), locating on government land (as at San Onofre), or even, considering the cost, of building on a man-made island as is planned for the power-desalting complex for Los Angeles.[16]

Interest During Construction. The amount of interest during construction appears to have been improperly estimated. The Parsons Study states:

> On the basis of using federal financing and assuming that capital costs are expended at a uniform rate during construction, a factor of 3.2 per cent is applied against the sum of equipment and facilities, land and land rights, site costs, and indirect capital.[17]

This would, of course, be the appropriate figure for straight-line construction if the construction period were somewhat less than

---

[15]For a 6000-foot ocean frontage, each "ocean frontage" acre has the unusual dimensions of 21 feet in width by somewhat over 2050 feet in depth.

[16]Most of the acreage required there is for the desalting plant flash evaporator trains, so that the size might be substantially reduced.

[17]Parsons Study, op. cit., p. 54.

two years. The traditional procedure for estimating interest during construction assumes a sigmoid curve for construction expenditures; then interest during construction can be estimated from the relationship

$$IDC = \frac{iT}{100}(L + 0.45C),$$

in which i is the interest rate in per cent, T is the duration of construction in years, L is land cost and C is construction cost; the factor 0.45 is a weighting factor indicating that construction expenditure is greater towards the end of the period than earlier.[18]

For the first four items of Table 1, adjusted as discussed above, interest during construction would amount to $18.14 million rather than $9.9 million.

FUEL CYCLE COSTS

Under this heading, we consider investment in fuel working capital, working capital charge rates, and nuclear fuel costs.

Investment in Fuel Working Capital. Item 7 of Table 1 lists investment in working capital as $77.3 million. The Parsons Study describes this as follows

> A total of $9,820 per megawatt thermal of reactor rating was utilized for fuel inventory. A percentage factor of 0.25 per cent of the sum of equipment and facilities plus depreciable site costs was used to estimate the cost of maintenance materials.[19]

The 2600 MWe of reactor rating at an efficiency of 33.3% would correspond to a thermal rating of 7800 megawatts resulting in an

---

[18] See, e.g., Geller, Hogerton, and Stoller, "Analyzing Power Costs for Nuclear Plants," Nucleonics, Vol. 22, No. 7 (July 1964), pp. 64-72. The value of T should be 4 years, not 2.

[19] Parsons Study, op. cit., p. 54

average investment of $76.6 million of the $77.3 million in fuel working capital. The $9800 per thermal megawatt corresponds then to an investment of $29.40/kw of electric capacity. For comparison, the Oyster Creek study lists average annual investment in fuel of $22 in Years 6-10, $26 in Years 11-20, and $24 in Years 21-30,[20] all of which are substantially below the value assumed in the Parsons Study. Improvements in core performance, reductions in fabrication cost, and a slight decrease in enrichment since the Oyster Creek Analysis suggest that current values are substantially lower. As an instance, PG&E's Diablo Canyon 1060 MWe pressurized-water reactor has an investment of about $20/kw, or $6380 per thermal megawatt.[21] Assuming working capital at $6500 per thermal megawatt, or $19,500 per electric megawatt, the fuel working capital investment is reduced to $50.7 million.

The preceding applies only to a consideration of baseloaded plants. For peaking plants, the average investment in fuel working capital is somewhat lower as fabrication and reprocessing occur less often, so that these costs are spread over a longer interval.[22] Thus, for peaking plants, the appropriate figure might be more on the order of $17,000 per electric megawatt. Of course, the annual interest on this amount is distributed over fewer kilowatt-hours per year, so that the fuel cost for the peaking plant lies above that for a baseloaded plant, as will be discussed subsequently. Inasmuch as the

---

[20] Oyster Creek Analysis, op. cit., Table 1.

[21] Pacific Gas and Electric Application No. 49501 Before the Public Utilities Commission, State of California, filed December 23, 1966, Exhibit J.

[22] For a more detailed treatment of this, see the now-classic article by John M. Vallance, "Fuel Cycle Economics of Uranium Fueled Thermal Reactors," P/247, Geneva Conference on Peaceful Uses of Atomic Energy.

baseloaded plants produce about double the kilowatt-hours per year of the peaking plant, fuel cost differentials due to varying load factor should be considered. These considerations are nowhere discussed in the Parsons Study.[23]

Working Capital Charge Rates. In addition to estimating a somewhat inflated value for fuel working capital investment, the Parsons Study further proceeds to levy a sinking fund charge (in addition to normal interest) against this amount. Working capital, of course, represents only a form of payment for expenses incurred in advance of revenues, and therefore the interest that could have been earned by alternative investment of these funds is added as an expense. The principal amount of the working capital investment is recovered in due course, and there is nothing whatever depreciable about this account. Therefore, the application of sinking fund charges against this account as is done in the Parsons Study is an unacceptable economic practice. Only the 3.222% interest rate should be applied to the average annual total.[24] Since the 30-year sinking fund charge rate (corresponding to 3.222% interest) is 2.027%, this represents an overcharge on the $77.3 million assumed by the Parsons Study of $1,567 million per annum.

Nuclear Fuel Costs. In addition to inflating the value of fuel working capital investment and improperly charging depreciation against this account, the Parsons Study appears to add working capital costs in a second time under the nuclear fuel account. The Parsons Study on the subject of nuclear fuel costs states:

---

[23] Additionally, it should be noted that the replacement figures of Tables E and G are different although both tables pertain to the same plant; it has not been possible to reproduce either set of figures from the data and directions in the Parsons Study. The true figures do appear to lie within the ranges of those figures, however.

[24] See, e.g., Geller, Hogerton, and Stoller, op. cit.

> The third core for a 650 megawatt electrical reactor is quoted in a manufacturer's handbook at 1.38 mills per kilowatt hour . . . The factors which enter into the 1.25 mills quoted for the Tennessee Valley Authority nuclear power plant are not fully known and although we can expect some reduction in cost if the plant were on a bid basis, the most reasonable value to assume for fuel cost appears to be about 1.3 mills per kilowatt-hour which is 0.05 mills higher than the Tennessee Valley Authority cost and 0.08 mills lower than the handbook values.[25]

We note first that 1.3 m/kwh times the 18.22 billion kwh per year generation assumed in the Parsons Study yields the fuel cost of $23,687 million of Table 2. Therefore, the Parsons Study has used a fuel cost of 1.3 m/kwh plus working capital charges which, under the Parsons Study methods of calculation, amount to an additional 0.22 m/kwh.

The reference to "a manufacturer's handbook" is evidently a reference to the 1965 General Electric Company pricing handbook, wherein the third core fuel cost for a 650 MWe single-cycle non-reheat nuclear powerplant is estimated to be as shown in Table 3.

---

[25] Parsons Study, op. cit., p. 54.

Table 3

650 MWe THIRD-CORE FUEL COST[26]

Single-Cycle, Non-Reheat

Component	Cost, M/kwh
Uranium Depletion	0.58
Pu Credit	(0.21)-credit
Recovery	0.21
Fabrication	0.48
Fuel Cycle Financing Cost	0.32
	1.38

[26] General Electric Co. Atomic Power Equipment Handbook, Sec.8805, Nuclear Fuel, May 24, 1965.

Note that the fifth item in this handbook listing is the working capital charge, so that the manufacturer's handbook price of 1.38 m/kwh includes working capital costs.

The TVA report states:

> The suppliers have warranted the cost (including the interest cost on the fuel inventory) of the heat produced, and therefore the evaluations include the interest cost on the fuel inventory as part of the cost of the fuel.
>
> Fuel costs for the BWR units range from 1.57 mills per kwh in 1970 to 1.09 mills per kwh by the end of the warranty period.[27]

Thus, both the G.E. and the TVA figures cited by the Parsons Study included working capital costs, whereas the Parsons Study assumed a fuel cost midway between those two figures, and then added in separately working capital costs resulting in a gross overestimate of fuel costs.

It should be noted that the G.E. figures on Table 3 assume working capital charge rates of 5% before irradition and 9% during and after irradition, whereas the TVA figures include working capital at only the 4.5% cost of money. Since the G.E. figures of Table 3 give an estimate of 1.06 m/kwh for fuel cost less working capital charges, and since the TVA charge rate is about half that assumed in the G.E. figures, adding half of the G.E. financing cost yields 1.22 m/kwh as an estimate of equivalent TVA third core costs (including financing charges on working capital) for a 650 MWe unit. In reality, the 1965 G.E. handbook fuel prices are based on less optimal design than is available to TVA or to new plants. The 1965 handbook was based on burnup of 20,000 megawatt days per short ton (MWD/T) of uranium, whereas present design burnup is 27,500 MWD/T.

---

[27] "Comparison of Coal-Fired and Nuclear Power Plants for the TVA System," Office of Power, Tennessee Valley Authority, Chattanooga, Tennessee, June 1966, p.5. The end of the warranty period is 1982, so that the 1.09 m/kwh is roughly representative of TVA third core costs.

Power density has also been increased by some 40%, coupled with a slight decrease in enrichment. All these factors suggest that even the assumption of 1.3 m/kwh for these plants based on the reports cited in the Parsons Study would have been somewhat on the high side even before working capital costs were added.

Since the Parsons Study was completed, G.E. has published a new fuel cost handbook, which revises upward several of the economic assumptions on which third core costs were based. For 600 MWe plants, third core costs are warranted at 13.87 cents per million BTU's and for 700 MWe plants, 13.83 cents per million BTU's.[28]

Then, by interpolation, third core warranted costs for a 650 MWe plant would be 13.85 cents per million BTU's, or at a net heat rate of 10,400 BTU/kwh, 1.44 m/kwh including financing charges at 5% and 9% as discussed previously. If financing costs represent the same fraction of costs as in the 1965 listing, this 1.44 m/kwh consists of direct costs of 1.10 m/kwh direct costs and 0.34 m/kwh financing charges. At 3.222% interest rather than the 5% and 9% rates used in the G.E. figures, financing charges might amount to 0.15 m/kwh, for a total fuel cost, <u>including</u> working capital charges, of about 1.25 m/kwh. Since the effect of the various Parsons Study procedures is to use a rate of 1.52 m/kwh, this reduction of 0.27 m/kwh on the 18.22 billion kwh per year means total annual fuel cost reductions of $4.92 million per annum, or about $369,000,000 over the 75 year period of analysis of the Parsons Study.

For peaking plants, fuel costs are probably about 1.35 m/kwh when the higher working capital costs for this mode of operation are added.

---

[28] General Electric Company, <u>Atomic Power Equipment Handbook</u>, Section 8803, Nuclear Fuel, Fuel Cycle Service, October 24, 1966, p.11. Figures are for single-cycle non-reheat plants for 1972 initial operation at an 80% load factor.

NUCLEAR PLANT REVENUES

The effect of the above charges (excluding possible reductions in land costs) is to reduce baseload nuclear generating costs (excluding transmission) by somewhat less than $5,000,00 per year; this would be sufficient to permit these plants to pay out without the use of revenues from Hoover, Parker and Davis at an interest rate of 3.222% (but the payout period would be protracted) but not at an interest rate of 4.5%. Since the annual generating cost figures with this $5,000,000 reduction are somewhat under 2.7 m/kwh neglecting transmission costs, this strongly suggests that the difficulties encountered by the Parson Study's nuclear plants lie on the the revenue side. As we have derived above, the average annual revenues to the baseloaded plants (18.22 billion kwh per year) are $53.11 million under the Parsons Study revenue assumptions. This is equivalent to a minuscule 2.91 mills per kwh sales price. Now the Bureau of Reclamation proposes to market power from the dams (if built) at $10 per kilowatt of capacity per year demand charge plus 3 mills per kwh for each kwh of energy generated.[29] From Table N of the Parsons Study, the hydro plants generate an average of 7.619 billion kwh per year and receive an average gross revenue of $37,622 million per year, for an average sales price of 4.94 m/kwh. Under the Parsons Study methodology the nuclear plants are credited with the same revenue for the first 7.619 billion kwh per year, but all kwh from that point to the 18.22 billion kwh assumed baseload generation is assumed to receive only 1.5 m/kwh! Since, as we have noted above, the implicit baseload fuel cost including working capital is 1.52 m/kwh, it should not be surprising to find that these baseloaded nuclear plants are not much different than the peaking plants.

---

[29] Utility rates are often expressed as a continued demand($1/kw-yr) and energy (m/kwh) charge. The capacity charge is, in effect, a fee paid to reserve a part of capacity output, and the energy of charge is an incremental charge. When a load factor is given, the demand charge can be allocated over the annual generation in kwh and added to the energy charge to derive an equivalent energy rate. Thus for a 40% factor for the dams, the $10 per kilowatt-year capacity charge is equivalent to 2.85 m/kwh so that the equivalent sales price from the dams is 5.85 m/kwh.

In justification of this extraordinarily low revenue assumption, the Parsons Study states:

> In the future, the proportion of peak electrical energy supplied by thermal power plants will increase because sites for additional hydroelectric power plants will not be available. Consequently, as long as power systems demand large amounts of peaking energy, the thermal plants, normally baseloaded, which will supply this peaking energy will have large amounts of "dump" energy available at incremental costs. Incremental fuel cost estimates range from 1.25 to 1.30 mills per kilowatt-hours for nuclear power plants and from 1.6 mills to 3.0 mills per kilowatt-hours for fossil-fueled power plants. Over the period of time covered by this study, because of the competitive nature of the resources industries, these incremental costs will tend to converge. If the cost gap does not close, the "defender" alternative of power generation, fossil fuel will become obsolete and not be selected for a fuel when contrasted to the "challenger" nuclear fuel. Consequently, 1.5 mills per kilowatt-hour have been used over the life of the payout period as the value to attach to excess power from the nuclear alternative. Perhaps early years will yield slightly higher revenues for off-peak energy, but later years will result in much lower revenues. Investigation of economy-intercharge agreements and elements of costs for thermal equipment rendered idle by the nuclear plant resulted in the conclusion that higher revenues for off-peak energy are not justified.[30]

A line by line rebuttal to this might proceed along the following lines.

> In the future, the proportion of peak electrical energy supplied by thermal power plants will increase because sites for additional hydroelectric power plants will not be available.

---

[30] Parsons Study, op. cit., pp. 77-78.

Quite true. The best hydro sites have already been developed, and additional sites tend to be less favorable from an economic standpoint.

> Consequently, as long as power systems demand large amounts of peaking energy, the thermal plants, normally baseloaded, which will supply this peaking energy, will have large amounts of "dump" energy available at incremental costs.

Not necessarily true. There are several forms of thermal plants which do not have "dump" energy available. Foremost of these are gas turbine peaking units, which have quite low capital costs and high fuel costs and are adapted to meet peak loads and occasional emergency power. Percentage increases in orders for this form of capacity have been greater in the last year than even that of nuclear plants. Another form is the pumped storage project, in which off-peak "dump" energy is used to refill the upper reservoir in preparation for the following day's peak load. Furthermore, there is no assurance that the divergent trend between peak and baseload will continue. Such developments as the electric automobile could in a relatively short period supply such a demand for "dump energy" for overnight recharging as to reduce the differences between peak and off-peak loads. This would, in turn, reduce the spread between peak and off-peak rates.

> Incremental fuel cost estimates range from 1.25 to 1.30 mills per kilowatt-hour for nuclear power plants and from 1.6 to 3.0 mills per kilowatt-hour for fossil-fueled power plants.

Hardly the case. In testimony regarding the offer of the California Power Pool to supply energy to the California Water Project Pumps, the range of incremental fuel costs for the PG&E, Southern California Edison Company, and San Diego Gas and Electric Company, ranged from a low of 3.1 m/kwh to a high of 5.01 m/kwh.[31]

---

[31] AEC Authorizing Legislation, Fiscal Year 1966, Part 3, Hearings Before the Joint Committee on Atomic Energy, Mar. 11, 18. 19, 24 and April 13, 1965, p.1571; data are from 1964 FPC report FPC S-166, Steam-Electric Plant Construction Cost and Annual Production Expenses-1964.

Also, the two most efficient steam plants in the central Arizona region had average incremental costs of 3.5 m/kwh.[32] Quite apart from this point, the installation of new capacity is ordinarily undertaken to meet growth in both base and peak load, and unless the peak load increases more rapidly than the baseload increases, new capacity has no dump energy available. Dump energy is largely available only from less efficient and more expensive plants that will be relegated to peak load service. Their cost of producing "dump" energy is not competitive. The present situation with dump energy widely available in the Northwest is essentially a short-term phenomenon.

> Over the period of time covered by this study, because of the competitive nature of the resources industries, these incremental costs will tend to converge. If the cost gap does not close, the "defender" alternative of power generation, fossil fuel, will become obsolete and not be selected for a fuel when contrasted to the "challenger" nuclear fuel.

This is sheer nonsense. The selection of fossil or nuclear capacity is based on overall production costs, not incremental costs. There is no reason either to expect the incremental cost gap to narrow or to expect one or the other form of capacity to vanish. So long as fossil fuel capital costs remain sufficiently far below nuclear capital costs, the resulting cushion will allow the use of a higher cost (fossil) fuel and fossil and nuclear plants can coexist. Incremental costs are used only in deciding the sequence in which a set of existing units should be brought on line, and not in deciding what kind of plant to build.

---

[32] F.P.C. Report S-171, Steam-Electric Plant Construction Cost and Annual Production Expenses - 1965, March 1966.

> Consequently, 1.5 mills per kilowatt-hour have been used over the life of the payout period as the value to attach to excess power from the nuclear alternative. Perhaps early years will yield slightly higher revenues for off-peak energy, but later years will result in much lower revenues. Investigation of economy-interchange agreements and elements of costs for thermal equipment rendered idle by the nuclear plant resulted in the conclusion that higher revenues for off-peak energy are not justified.

To deal with the last point first, any capacity that is "rendered idle" by the nuclear plants will remain idle only until the load grows to accommodate the nuclear plants. Since the growth of peak load on the PG&E system alone is forecast to be in excess of 650 MWe per year,[33] the idling would extend at most only four years. Crucial to the argument, of course, is the need to integrate the plants into the various utility networks. In this respect, the California Power Pool proposal is instructive; the proposal letter states:

> However, should the State decide to install initially its own atomic generating facilities, the suppliers are willing, as we have indicated in previous meetings, to cooperate in contracting for the integration of such facilities into our interconnected systems and for the operation of the plant by one or more of the suppliers.[34]

The Power Pool contract, incidentally, established 3 mills/kwh as the rate to the California project, and this is the lowest rate available to any of the Pool's customers, based on the large block required. By contrast the Metropolitan Water District, another large user, paid 5¼ mills/kwh for off-peak energy.[35] Thus we might infer that in the "early years" revenues will be substantially above 1.5 mills (not "slightly"); also since the floor is somewhere around 1.3 to 1.4 m/kwh representative of private utility incremental

---

[33] PG&E Application 49501, op.cit., Exhibit G. Area load growth is in excess of 3000 MWe per year.

[34] AEC Authorizing Legislation-1966, op.cit., p.1568. The suppliers are Southern California Edison, San Diego Gas and Electric, Los Angeles Department of Water and Power, and Pacific Gas and Electric.

[35] Ibid., p.1573

costs, "later years" can hardly result in "much lower" revenues than the 1.5 m/kwh assumed. On balance, 1.5 m/kwh appears to be an extremely unlikely assumption as to off-peak revenues over the next 75 years. Even on an economy-interchange basis, revenues should easily be in the 2.25-2.5 m/kwh, and that is probably a minimum estimate. Needless to say, at higher revenues, the nuclear plants turn out to be quite effective contributors to a Development Fund.

NUCLEAR VERSUS HYDRO FOR THE COLORADO BASIN

The preceding discussion has for the most part focused on the economics of nuclear power in the abstract; the Parsons Study, however, is intended as a specific comparison of nuclear plants versus hydro plants as contributors to the Basun Development Funds. In evaluating this specific comparison, the Parsons Study has applied what, for want of a better term, might be described as "Robinson Crusoe Economics." The meaning of this will become plain when we consider how a "comparable" nuclear alternative was selected.

Hydro

The two dams have an aggregate rating at site of 2100 MWe, and the largest generating unit is 250 MWe, so the rating with one unit down is 1850 MWe at-site. Hualapai at 1500 MW would primarily supply energy to Southern California, and Marble at 600 MW would primarily supply Arizona and the Central Arizona Project pumps at Lake Havasu.

The Parsons Study Nuclear Alternative

The Parsons Study selected a total of four 650 MWe nuclear plants, so that with one unit out of service, the aggregate rating would be 1950 MWe, or 100 MWe <u>more</u> than the dams.[36] They state that the fourth unit is intended primarily as backup. Also, transmission lines (at initial cost of $141 million) are provided between Los Angeles and Phoenix; when all four plants are located

---

[36] Or 1880 MW net with two at Los Angeles and one in Arizona on-line.

at Los Angeles, this provides for the Arizona load; when 3 are in Los Angeles and one in Arizona, the lines "would still be required in order to provide the necessary reserve backup for the one unit in Phoenix."[37]

On the revenue side, however, hydro revenues are computed on the basis of full rated capacity (not one unit out capacity), while the nuclear plants are credited only with the same generating hours and revenues as the dam with the additional capacity during peaking hours and the added availability at other hours given no credit. In the baseload case, all kilowatt-hours produced by the nuclear plants in excess of those generated annually by the dams are evaluated as off-peak despite the fact that 50% of the hours in a week by utility definition are on-peak hours, although the dams operate only 41% of the time. In addition, the deliverable capacity of Hualapai is only 1350 MWe and that of Marble is only 552 MWe due to losses in transmission from the remote dam sites to load centers. Since the nuclear alternatives are located at load, losses are negligible. These effects have not been evaluated in the Parsons Study. Thus for the nuclear alternative, peaking revenues are substantially understated.

The Parsons Study thus envisions a comparable alternative to the dams as a completely self-contained power generation system with its own full reserves, and with full backup interconnection among units. It is as though in the service area there were no other generating capacity, transmission lines, reserves, emergency, interchanges, and the like -- hence the term "Robinson Crusoe Economics."

However, the Parsons Study assumptions are not even least-cost "Robinson Crusoe Economics", as the following example shows:
For three plants in Los Angeles and one in Arizona, the $141 million transmission line at 3.222% and 50 year depreciation has an annual cost of $5.713 million plus annual operating and maintenance costs of $1.973 million for a total annual cost of $7.686 million. Four 140 MWe gas turbine peaking units could provide 560 MWe capacity

---

[37] Parsons Study, op. cit, p.41

(slightly more than the deliverable capacity of 552 MWe of Marble) for a total investment cost of $44 million.[38] Since they would be used only for standby we might assume a 50 year service lifetime for these units, in which case the annual investment cost is only $1.783 million, even assuming no credit for standby emergency service. Thus even in the Crusoe world of the Parsons Study the cost of the nuclear alternative has been overestimated by almost $6 million per year. Much the same argument could be directed to the fourth nuclear plant. Since under the Parsons Study assumption, it never receives any peaking power revenue, but instead receives only 1.5 m/kwh, its replacement by five 140 MWe gas turbine peaking units would cost about $55,000,000, or about $2.229 million per year, which is less than the annual investment and operating cost minus the assumed baseload revenue of the fourth plant. Of course, for realistic revenue projections, the fourth nuclear unit would be preferred.

USE OF BUREAU OF RECLAMATION CALCULATIONS

A final point pertains to the estimates by the Bureau of Reclamation of annual costs and contributions to the Basin fund. The Parsons Study has used without modification the figures developed over the course of the past few years, which have been shown to be of limited accuracy. In particular, since costs for the dams were estimated some years ago, general price escalation during the intervening period has raised the cost of the dams by some ten to fifteen percent. Also, the calculations by the Bureau neglected certain other expenses, such as $34 million for an after-bay on the river below Marble Canyon Dam to re-regulate the flow of the Colorado through the Grand Canyon, an undetermined amount as compensation to the Hualapai Indian tribe for encroachment on reservation lands,[39] and a charge against power revenues for the amount of water evaporated by the dams.

---

[38] Prepared Testimony of Alexander Lurkis, Alexander Lurkis Associates, Consulting Engineers, before the Federal Power Commission, Project No. 2338, (Cornwall Project), 1966.

[39] The Navajos apparently would not object to some compensation also.

Hydro "Fuel"

With regard to this latter point, the Parsons Study has (rightfully) charged the Arizona power plant with the cost of cooling water. The baseload plant is assumed to use 13,000 acre feet per year, and the peaking plant, 5,700 acre feet, charged at $50 per acre foot. Parsons also makes much of the phrase "The nuclear plant requires fuel; the hydroelectric plant requires none." In the ordinary sense of the word, perhaps not; but hydroelectric power does require impounded water, which is subject to evaporation and other losses. Evaporation is particularly critical in this instance since, as has been pointed out, the waters of the Colorado River are already over-allocated; thus every extra acre-foot evaporated behind a dam is an acre-foot lost to some beneficial consumptive user further downstream.*

When the purpose of a dam is flood-control or storage and diversion, the annual evaporation can with some justification be imputed to these items, but (since Lake Powell lies immediately above Marble Reservoir and Lake Mead immediately below Hualapai) neither flood-control nor storage and diversion can be claimed in this instance. Therefore, the annual reservoir evaporation in excess of that which would occur in the absence of the dams is in a very real sense a cost of the power produced. Although there is some uncertainty as to the actual extent of evaporation from the proposed reservoirs, the Bureau has admitted that at least 85,000 acre-feet per year from Hualapai and 10,000 acre-feet from Marble would be lost (over and above what is presently lost from the stretches of the river to be inundated).**

In summation, then, the Parsons Study contributes little to our understanding of either present nuclear power economics or the substitutability of nuclear power for dams in the Lower Colorado Basin.

---

*In this instance, to Southern California, since it currently withdraws from the Colorado more water than that to which it is entitled under the Supreme Court decision.

**At an imputed cost of $50 per acre-foot -- typical of municipal and industrial rates obtainable for water -- the annual cost of the hydro "fuel" would be $4.75 million.