ECONOMIC AND FINANCIAL ANALYSIS OF HYDROPOWER

Edmund Barbour

Introduction

This second International Waterpower Conference is evidence of resurging interest in the development of hydroelectric power. Potentials for harnessing the kinetic energy of water are being carefully reexamined, as many nations face increasing scarcities and costs in fossil fuels, and seek energy independence. In underdeveloped areas, there are still unanalyzed potentials for large conventional hydropower sites; however, in most developed areas of the world, dramatic improvements in economics have resulted in reanalyses of existing hydropower projects and undeveloped, relatively low-head sites previously discarded as lacking feasibility. In the coterminous United States, current studies suggest that remaining practical potentials (excluding the few unbuilt environmentally sensitive conventional high-head sites) are dominated by: the addition of capacity at existing hydroelectric plants; retrofitting existing dams and water conveyance structures not now producing electricity; a large number of relatively small scale, often low head, energy producers; and finally, specialized hydropower projects of large size, employing pumped storage that rely on conjunctive development of thermal coal and nuclear baseload plants.

Some brief initial comments on the role of hydropower in the national energy picture provide perspective on the economic driving forces in the energy field. It should be clear from the outset that new hydropower will not be the decisive factor in energy resource allocation decisions, but rather, it will be responsive to other controlling factors. Nevertheless, hydropower as a renewable resource can make important contributions to meeting future needs. Electricity is a vital source of United States energy, as it supplies almost one-third of its total needs, with hydropower accounting for about 13 percent of that electricity nationwide. It is twice as important in the 17 Western States, where hydropower accounts for 26 percent of electricity.

Turning to the future for more insight, projections for year 2000 suggest lower electric growth rates of from 2 to 4 percent, rather than 7 to 9 percent in the 1960's and 1970's; some increase in the proportion of energy represented by electricity; and a reduction in the contributions of oil and gas. Major uncertainties affecting the likely electric generation mix involve the potential

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contributions of nuclear and solar power. Fuel mixes vary significantly among power market areas in the United States now, and will continue to do so in the future, though moving more heavily in the direction of coal. Thus, coal, if it is not impeded by the potential CO₂ "greenhouse" problem, will likely play the most important role, since nuclear power must still shed its albatrosses of safety and disposal. Thus, the economic studies of hydropower must realistically reflect existing and future energy developments and market conditions within the specific market areas within which it will operate. For example, the northeast and the Pacific southwest are highly reliant on oil, which provides greater economic incentive for hydropower in those areas.

Sound economic and financial analyses are important nationally in allocating the use of dwindling resources of conventional hydropower and in assessing the large remaining potentials for pumped storage. Current national policy and legislation encourages accelerated development of hydropower in both the private and public sectors. Because of the great number of sites involved and lead times required before construction starts, it will require a combination of public and private effort to get the job done. These potential developers cover a broad spectrum of entities, including investor-owned utilities, municipalities, cooperative associations, water conservation and public power districts, private entrepreneurial groups, as well as Federal water agencies such as USBR (Bureau of Reclamation) and COE (Corps of Engineers).

Both USBR and COE are conducting assessments of hydropower potentials, and due to the size of the effort, employ private consulting firms. Because of the widespread interest in hydropower, those firms are involved in conducting economic studies for both Federal and non-Federal developers. On the other hand, as most of the potential hydropower development at existing Federal structures is being filed on by non-Federal developers, sometimes two or more for the same site, the Federal agencies in turn are involved in the economics of non-Federal development. Economic or financial tests may vary significantly among those entities, which suggests that knowledge and understanding of those variations could be useful in making decisions on hydropower development from a national viewpoint. To provide some of that insight is the major objective of this paper, with the emphasis on Federal procedures. Although environmental and social impacts are also important factors to be weighed, the ability to meet certain economic and financial tests is an essential first step in the selection process.

Distinctions Between Federal Economic and Financial Analysis

After over 30 years of developing and reviewing literally thousands of economic and financial analyses, I believe I can discuss with considerable familiarity Federal agency procedures
that are actually being implemented; however, I must admit superficial knowledge on the non-Federal aspect. First, let us address the distinction between "economic analysis" and "financial analysis," which have different meanings in the jargon of the Federal water planning establishment, as the former concentrates on whether a project is a worthwhile Federal investment, while the latter on who and how the project should be paid for.

**Economic Analysis**

Federal economic analysis normally refers to the monetary comparisons of annualized streams of benefits and costs measured from a national viewpoint, and often expressed in terms of a ratio. (Assuming a discount rate and time period, comparisons are also made in terms of present worth lump-sum equivalents.) The framework of analysis reflects measurements of differences in future conditions with and without the proposed water plan, and thus as in all planning endeavors requires projections into the future. The general setting has been multipurpose development of water resources, with hydropower given a secondary or supporting role to other purposes such as flood control, irrigation, navigation, municipal and industrial supplies, fish and wildlife, and recreation. Water resource development in the United States has attained a high degree of maturity in that most of the large feasible storage potentials have been developed and consequently, there is considerable competition among purposes in planning for the conservation and use of remaining scarce supplies. Environmental and social objectives in the last decade or so have been receiving more emphasis, as opposed to pure economic efficiency. This has resulted in public demands for a national water policy and more uniformity and consistency in evaluation of water projects. Hence, the creation of the WRC (Water Resources Council) in the late 1960's, and the currently continuing development of P&S (Principles and Standards) beginning in the early 1970's. They are intended to govern Federal water planning agencies and have recently been printed as rules and regulation in the Federal Register. 2/

**Benefits.** - On the benefits side of the equation, real or simulated market prices are traditionally used to measure the output of water project services. Since these services are rather unique, and there are no active "free" markets for water-related outputs, the dollar values are estimated to represent increases in net incomes to the beneficiaries, or the price they would be willing to pay for comparable services produced by a likely alternative within the particular market area within which they would have a choice. The resulting values are usually referred to as "simulated market prices."

Inasmuch as the market place was the best and only source of price data, estimates of value are to recognize those factors that realistically influence prices within a given market setting. Considering the fact that electricity was a highly vendible
product and that there was always an alternative source available at a price, it was by far the easiest of the water outputs to establish a price through market simulation procedures. One does not have to search far into the literature to confirm the long standing controversies in measuring economic benefits from other purposes such as irrigation, flood control, navigation, and more recently, outdoor recreation.

From 1950 until 1973, as expressed in documents generally reflecting Federal interagency agreed-upon procedures 3/4/, monetary benefits were delineated into two categories: (1) "direct" or "primary" effects measured at the point where the project output was initially used, and (2) "indirect" or "secondary" effects to refer to benefits accruing beyond that point of first use. Suffice it to say that there was considerable argument in the economics profession as to what portion of the second category represented a true national economic gain or simply a transfer from one region to another.

In 1973, the WRC P&S introduced a four-account system of evaluation: (1) NED (national economic development); (2) RD (regional development); (3) EQ (environmental quality); and (4) SWB (social well-being). Components of these accounts have been somewhat modified, reshuffled, and renamed in the 1980 published version which changed RD to RED (regional economic development), and SWB to OSE (other social effects). (Hopefully, this will not confuse the reader too much, but will solicit some compassion for the long-suffering Federal water planners, who have had to deal with these terms for the last decade or so.) The "direct" benefits to the initial users are reflected in the NED account, with additional provision made for estimating "external economic efficiencies," and "unemployed and underemployed resources" during construction under special circumstances. For lack of definitive agreed-upon procedures, these additional categories have not seen much use. The "indirect" monetary effects generally ended up in the RD account. This is not to say that the concept of a four-account system did not provide for some improvements in the evaluation process, but simply to give the reader perspective on Federal economic analysis.

Although the P&S does not call for the preparation of a b/c (benefit/cost) ratio for the NED account, since the P&S emphasizes the estimates of net benefits (NED benefits less NED costs), most active projects were authorized and many evaluated prior to 1973, and because of congressional custom, b/c ratios continue to be reported. Since criteria, both for evaluating benefits and setting the discount rates, have changed considerably prior to 1973, great caution must be exercised in comparing b/c ratios for earlier authorized projects and those currently being investigated. Unfortunately, the game of comparing b/c ratios is played with great fervor, with the players having little information on the underlying assumptions.
Obviously, before a b/c ratio can be calculated, the project must be scoped or formulated, and tradeoffs among purposes must be taken into account. The monetary measures of benefits, especially to the direct users, can play an important part in selecting the best plan. In the case of hydropower benefits, they are not only used in scoping generating facilities, but also in measuring power benefits foregone, where a decision must be made between generating more or less electricity or consuming more or less energy in providing project services. In these critical energy times, it behooves the analyst to properly evaluate the NED benefit from hydropower. Because of growing difficulties of developing fossil fuel resources, history has demonstrated that we have underevaluated and consequently underdeveloped hydropower potentials. It would have been better to have erred on the high side in estimating hydropower benefits rather than underpricing that limited resource.

Costs. - On the cost side of the equation, measurement of project inputs is considerably easier. Market prices are available to identify the cost of constructing and operating physical project works. The conversion of costs and benefits to a common time basis for purposes of comparison requires the assumption of an interest or discount rate. The determination of the "right" rate has been a subject of great and long controversy, but nevertheless has been resolved (though perhaps temporarily) by Congress and executive policy, and is established annually by WRC. The current rate is 7-3/8 percent. To complete the cost picture, present procedures make provisions to include dollar estimates of "external diseconomies" to balance off recognition of the same factor on the benefits side, and is subject to the same computational problems. Economic theorists suggest that consideration of underemployed or unemployed resources actually represents a reduction on the cost side of the equation, rather than an increase in benefits. There is support for dealing with this factor completely separate from both sides, and to use it as an administrative tool in the final prioritization of an array of public water investments.

Incremental b/c Analysis

Because of the large proportion of hydropower potential that occurs at existing dams or structures, the use of the incremental b/c approach should be highlighted. In formulating a hydropower addition, the determination of economic justification assumes that already expended costs are "sunk," and that a minimum requirement is that "new" benefits cover "new" costs. In the final b/c comparisons, an assignment of costs for use of existing facilities may be made to a planned increment, especially where there are opportunities for alternative use of that facility. This is somewhat different from the financial or repayment analysis discussed subsequently, where cost-sharing rules require that hydropower help pay for the use of existing facilities if there is a residual of power benefits in excess of added costs. This is
more of a question as to who should pay, rather than whether is is a worthwhile undertaking from a national standpoint.

Federal Financial or Repayment Analysis

Each water project proposal must show a repayment plan to provide decisionmakers insight on how much would be financed initially from the Federal Treasury, if any, and how much revenues would be returned during some reasonable time frame. The final decision on what costs are to be considered reimbursable or nonreimbursable, how much "front end" funding participation is required, and the interest rate and amortization period are all established by Congress, often on a case-by-case basis. It is common knowledge by almost all interested parties that national cost-sharing policy for various water project services needs to be clarified and made more consistent. Having participated in a number of efforts in this regard over the last decade I doubt whether Congress, without great pressure from the Executive Branch, will face up to these difficult questions in the future.

As to hydropower, repayment policy has been rather clear that all costs, including interest at a specified congressional rate, should be recovered within a 50-year period after facilities become revenue producing. Based on current formulas generally followed in both the legislative and executive branches, that interest rate is approximately 8-1/2 percent. This may establish the minimum rate charged for hydropower, as Congress in the past has authorized the use of "surplus" power revenues - over and above that required to meet power repayment requirements - to assist in the repayment of project costs allocated to other purposes, principally irrigation. The underlying theory is that locational advantages from resource development of a water basin should accrue to those located in that basin, which often embraces the power-user customers themselves, who in turn benefit indirectly from the water project. The combination of a number of projects into basin accounts with hydropower providing surplus revenues to assist irrigation has been authorized by Congress for most large basins in the West.

The major basin accounts include the Pick-Sloan Missouri Basin Program, Columbia Basin Project, Central Valley Project, Upper Colorado River Storage Project, and Lower Colorado River Basin Project. These involve relatively large power systems, and encompass both USBR and COE hydropower projects. They provide inter basin project power needs, with the remaining power sold commercially under a preference clause which gives publicly owned utilities first call on the purchase of power. A large portion of the undeveloped power at existing Federal facilities in the Western and Great Plains States would be located within one of these basins, and if constructed by a Federal agency, would be integrated in those systems. Marketing of that power in those basins would primarily be the responsibility of two marketing administrations BPA (Bonneville Power Administration) and WAPA.
(Western Area Power Administration). Three other marketing entities would have responsibility for Federal hydropower additions in other parts of the United States: Southwest Power Administration operating in south-central States west of the Mississippi River, Southeast Power Administration, covering southern States east of the Mississippi River, and Alaska Power Administration in Alaska.

As most of the potential hydropower development at existing Federal structures - with probably the exclusion of major pumped storage - would likely be absorbed into existing systems, costs of new developments would be financially integrated and recovered as a part of the overall rate-making process through average pricing. Very large additions of hydropower may require an incremental pricing approach. Examples would be large amounts of hydropower capacity without energy, or pumped-storage capacity where the purchaser may be required to provide the associated pumping energy requirements. Purchasers of these types of capacity normally plan to offset costs through savings in substituting peaking plants burning expensive oil for off-peak baseload plants fueled by coal or nuclear energy.

**Non-Federal Economic Studies**

From the viewpoint of the non-Federal developer of hydropower, economic studies concentrate on financial tests, comparing expected future revenues to out-of-pocket costs. If the developer has responsibilities to meet total electric demands in a particular market, a comparison with alternative costs likely to be displaced by hydropower would be an important part of the decision. This is consistent with the concept of simulated market prices which governs Federal Project benefit evaluation and willingness to pay. Out-of-pocket costs vary significantly with the entity involved and are influenced by a large number of factors, among which are money market conditions, availability of tax-exempt bonds, special study grants, investment tax credits, local fuel severance taxes, accelerated depreciation rates, as well as other factors.

Also, the developing entity influences the disposition of the hydroelectric output and the recipients of savings - if any - which may be passed on to the power users. From a national viewpoint, these factors can have differing direct and indirect economic consequences, which unfortunately are difficult to measure, as there is little agreement in the economics profession as to how this can be done.

Although non-Federal entities do not prepare b/c ratios from a national viewpoint, it is logical to assume that the value to the nation of 1 kWh of hydroelectric power from a given project would be the same regardless of the developing entity. Thus, for example, in a particular power market area, if after all actual
market factors are recognized and the simulated market price of a low-head energy producing project as measured at the margin is 60 mills/kWh, that value should provide at least a minimum measure of the power benefit in that power market area in which resource allocation decisions are being made daily. The word "minimum" is used because of the certain intrinsic values of hydropower that, with present techniques, escape price measurement. Those often-mentioned values include such unique characteristics as high reliability, fast loading and quick response capabilities, low exposure to price inflation, spinning reserve capabilities, and certain environmental advantages. From a national viewpoint, an additional benefit for the use of a renewable resource might be claimed, especially as it affects energy self-sufficiency, and international trade balances. Yet these extra values, if measured, should remain constant from the national viewpoint regardless of the development entity.

On the other hand, the financial, out-of-pocket net costs would vary substantially by developing entity. To follow through with the hydropower example above, if the dominant rate-setting force at the supplier level was the marginal costs of an IOU (investor-owned utility), the "benefits" of 60 mills/kWh would also represent the costs of the likely thermal alternative which simulated a market price reflecting willingness to pay. If the project's financial costs for the IOU based on constant current dollars were 50 mills/kWh after tax credits, it would represent a feasible investment, and the 10-mill savings ultimately would be passed on to the consumers when averaged into the rate structure.

A non-Federal public entity (such as a municipality or a water conservation district) would have different out-of-pocket costs, because of availability of tax-exempt bond financing and lower taxes. Assuming out-of-pocket costs of 35 mills/kWh and the municipality provided its own electric services, it could internally pass the savings on to users. This could be either in the form of electric bills that would have otherwise been lower, in reduced local taxes, or the provision of additional public services. If the example hydroproject were small-scale qualifying under PURPA 6/, the municipality could theoretically sell it at the avoided market cost of 60 mills/kWh (less adjustment for transmission, if necessary) with the possible savings disposed of as indicated above. Any grants from various Federal programs obviously would further reduce costs.

Determination of out-of-pocket costs would be more complicated if the illustrated hydroplant development took place by a private entrepreneurial group. Under PURPA, it is possible that the output could be sold for the aforementioned 60 mills/kWh. Net out-of-pocket cost would be highly dependent on tax credits. Important would be the amount of investment tax credits, provisions for accelerated depreciation, and any other advantages that might accrue from grants, and possibly partial financing by industrial-type tax-exempt bonds. Also, impacting financial costs
would be the potentials for offsetting taxable income from other investments, which has been recognized as quite critical to the financial feasibility of the hydropower development. \textsuperscript{7} The net financial costs after taxes would have to be less than the expected revenues of 60 mills. Resulting profits which would then accrue to the independent private investors with investment income flowing to wherever they were located. The electric output would go to whatever power marketing entity that would purchase that power, with the full 60-mill cost paid by their customers.

From a non-Federal financial viewpoint, one critical element is whether a Federal structure is involved. If privately owned, the developer must negotiate for the use of that facility. If federally owned, current criteria call for a sharing of net benefits or net revenues. Another approach is the allocation of a portion of the sunk Federal costs to the non-Federal developer, following the agencies cost allocation formula, with the resulting amount repaid by the developing entity. Any payments for the hydropower privileges or "falling water" charges would go to the U.S. Treasury and most likely be accounted for as a part of a basin fund. Considering the number of filings on Federal structures, 627 filings on 394 Federal structures \textsuperscript{8}, further clarification of policy as to which entity has priority is obviously needed.

To complete the circle of comparison of economic and financial analyses involving the various entities, let us assume that the hydropower illustration above was located on a Federal structure and was analyzed for Federal agency construction.

If no other multiple-purpose benefits were involved, and there were no adverse effects on existing operations, the NED costs could fall somewhere between the financial costs of the municipality (especially if the city had a high Standard and Poor credit rating), and the IOU, say 40 mills. When compared to the simulated market price of 60 mills, it would result in a net NED benefit of 20 mills/kWh and a b/c ratio of 1.5 to 1.0. Because "financial" or "repayment" costs are to be recovered at a somewhat higher interest rate over a shorter period according to current Federal policy, this could enlarge the cost to be recovered to say 45 mills/kWh. The chances are that the electric output would be integrated into a basin system and marketed by one of the power marketing administrations. First call on the output would be by preference customers, with any remaining going to private utilities. Depending on the amount, character, and transmission accessibility of the output, any or all of the aforementioned utilities could receive shares, and in turn would pass savings on to their individual customers.

The above is obviously an oversimplification and was designed for illustrative purposes only, to promote understanding into the various aspects of economic and financial analysis as it might be perceived from differing viewpoints. A great number of other
factors involving environmental, social, legal, and institutional factors may have even more relevancy. Although there may be considerable agreement that the benefits to the nation should be essentially the same as best approximated in the market place, there could be long discussions concerning variations in the "true" economic costs to the nation among competing developers. Probably it will never be known because the subject involves complex economic issues relating to "transfer" payments among economic regions, incidence of taxation, and finally the distribution of income - all subjects which evoke theoretical arguments long into the night.

**Hydropower Benefits in Particular**

A few summary remarks on a favorite subject, which will apparently be well covered during other papers and sessions of this conference. From the beginning of the publication of the first "greenbook" of interagency guidelines in 1950 and its revision in 1958, through the publication of SD97 in 1962; Federal Power Commission guidelines in 1968, P&I in 1973, and Federal Energy Regulating Commission guidelines in August 1979, the general approach for evaluating power continued to follow the concept of the use of real or simulated market prices and the willingness to pay for alternative costs likely to be incurred in the absence of the hydropower project. The emphasis focused on the recognition of actual market place conditions. The 1979 NED manual reiterated the concept of simulated market prices and willingness to pay, and added direct measures of marginal costs as a criterion. It also permitted the use of a short cut procedure for small-sale hydropower acknowledging the use of values to represent marketability or saleability of the hydropower output in the marketplace. This actually reinforced earlier procedures. The advent of PURPA requiring purchase of electricity from small-scale renewable resource projects at actual avoided or incremental costs is helping to establish direct measures of marginal costs and marketability in specific market areas.

The NED Manual, however, introduced an innovation when it specified that in the absence of direct measures of marginal willingness to pay, the likely alternative costs are to be used but constrained by certain nonmarket conditions. It required that Federal NED economic criteria regarding interest rates and taxes be imposed on the thermal powerplant alternatives. Since traditionally Federal agencies have been using actual market conditions and financial criteria to estimate system costs at the margin, this change in procedural rules appears contradictory to the market-oriented conceptual base and has caused difficulties in converting all components of hydropower benefits to Federal financing. Based on current price data, the change results in significant reductions in the current simulated market prices and under estimating of what power customers are willing to pay and actually are paying. The resulting underevaluation would not be
consistent with current congressional and executive policies to encourage the use of renewable resource-based electric generation and would not support energy conservation in comparing tradeoff values commonly faced in water project scoping studies between producing (i.e., generating) or consuming (i.e., pumping) electricity.

The NED Manual's use of "federally" financed thermal plants in benefits evaluation, confuses benefit evaluation with the "comparability test" required in plan formulation covered in the plan formulation section of the P&S. That test, which has been in effect since 1962, states that in the plan selection process comparisons of alternatives which may be economically or physically precluded should be analyzed in comparable terms. This evaluation would include both monetary and nonmonetary measures under the four-account system discussed previously. Aside from multiple-purpose considerations, in the case of hydropower in an undeveloped area where there is a real choice between hydropower and thermal alternatives, the application of comparable economic criteria should be made. This may be more effectively tested on the cost side of the b/c equation since it can be assumed that benefits are essentially equal among alternatives. The availability of data on economic, environmental, regional development, and social aspects would be equally important in the decision process when actual choices must be made.

The NED manual commendably places a greater emphasis on the use of system models which is now being actively pursued by USBR and COE, with technical assistance from FERC. The recognition of price shift analysis, which permits the accounting for real price escalation in fuel costs, is another improvement in procedures contained in the Manual. Another plus is the further emphasis on the recognition of intermittent capacity values of hydropower when operating in other than drought hydrologic periods. Recommendations for implementing procedures for the NED Manual are now being developed by an interagency field team effort and is being reported on in another session of this conference.

Summary Comments

Economic and financial analyses mean different things to different entities. From the Federal development agency perspective, economic analysis has to do with justification by comparing benefits and costs from the Federal viewpoint often expressed as b/c ratios. Multipurpose development with hydropower as an important adjunct, has been a long-time objective. In large basin areas of the West hydropower revenues provide financial assistance to irrigation development as a part of congressionally established basin accounts. Federal financial or repayment analyses concentrate on recovering certain congressionally specified costs and terms, which establishes the Federal/non-Federal cost-sharing picture. Since a large proportion of the logical next hydropower additions involve existing Federal structures, the treatment of
already expended ("sunk") costs can influence both the economic and financial analysis of the Federal agencies, as well as financial studies of the various non-Federal entities having interests in developing hydropower. Financial studies by the various non-Federal entities concentrate on comparisons of out-of-pocket costs compared to potential revenues. Those costs are influenced heavily by interest rates, tax assessments, and tax credits, among other things. The developing entity influences who finally receives the hydroelectric output and the extent to which savings, if any, over thermal alternative costs are passed on to power users. With the exception of some confusion on whether a thermal plant analyzed using Federal NED economic criteria properly reflects real market conditions, improvements in hydropower benefit evaluations are being made by emphasizing computerized systems modeling and recognizing projected real escalation in fossil fuel prices.
FOOTNOTES AND REFERENCES

1/ To exemplify that charge, the table on page 14 is provided. Data for 1969 taken from my paper "Power Values in Multiple-purpose Water Project Evaluation," prepared for Symposium on Problems of Multiple Purpose River Development, United Nations Economic Commission for Europe, Committee on Electric Power, Madrid Spain, October 20-11, 1969. The plant factors have been modified and the fixed charge of 9 percent for the 1969 base was increased to 15 percent for 1981, which reflects power market conditions in the southwest United States.

2/ First printed in the FR (Federal Register), Vol 38, No. 174, Sept. 10, 1973, as a "Notice" approved by the President; subsequently implementing procedures were published as "Rules and Regulations" - "Procedures for Evaluation of national Economic Development (NED) Benefits and Costs," FR, Vol. 44, No. 242, Dec. 14, 1979; finally a revised and abbreviated addition of the P&S was published as "Rules and Regulations," FR, Vol. 45, No. 190, Sept 30, 1980. The shift from "Notices" is considered to give the guidelines the force of law which make noncompliance subject to legal recourse.


5/ Perhaps the most comprehensive analysis comparing cost sharing rules among agencies and programs is the Water Resources Council report "Option for Cost Sharing: Cost Sharing Issues - Dimensions, Current Situation and Options," Part 5A, September 1975, which was the result of a 1-year Presidential Study in conformance with Section 80(c) of the Water Resources Act of 1974 (Public Law 93-251).


Comparison of marginal costs of alternative thermal powerplants, 1969 and 1981

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<th>Fixed capacity $/kW yr</th>
<th>Variable energy mills/kWh</th>
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