DOE/EIS-0093-F

1982 RATE PROPOSAL

FINAL ENVIRONMENTAL IMPACT STATEMENT

BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY
AUGUST 1982

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Responsible Official:
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Environmental Protection, Safety,
and Emergency Preparedness

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I. COVER SHEET

U.S. DEPARTMENT OF ENERGY
(DOE/EIS 0093-F)
ENVIRONMENTAL IMPACT STATEMENT

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Prepared By
Bonneville Power Administration
U.S. Department of Energy
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Abstract

This statement evaluates the potential physical and socioeconomic environmental impacts associated with an increase in the wholesale power rates of the Bonneville Power Administration (BPA). Examined are the effects of an increase in power rates in 1982 and the cumulative effects of rate increases occurring or scheduled to occur during the period of 1979-1985. Included in this analysis are environmental impacts expected from implementation of five alternative revenue level scenarios: a no action alternative, the proposed BPA alternative, which would produce a 43 percent increase in revenue relative to revenue which would be generated under exisiting rates, a modification of the proposed alternative to reflect potential changes in BPA repayment policy, a long run incremental cost (LRIC) alternative, and a phased-in LRIC alternative. Effects on regional generation requirements, substitution of other fuels for electricity, effects on utility costs and on retail electricity rates, and impacts on consumers and regional irrigated agriculture are major areas of analysis. The potential impacts associated with a variety of rate designs and alternatives to BPA's proposed rate schedules for priority firm power, industrial firm power, new resources firm power, nonfirm energy, and wholesale firm capacity are also addressed. Discussions of measures to mitigate the environmental impacts of both revenue level alternatives and rate design alternatives are presented.

II. 1982 BPA WHOLESALE RATE INCREASE ENVIRONMENTAL IMPACT STATEMENT EXECUTIVE SUMMARY

A. Purpose and Need

The Bonneville Power Administration (BPA) has determined the need to increase its wholesale power rates to enable it to meet its financial obligations. BPA is proposing rates, which if approved by the Federal Energy Regulatory Commission, would take effect on October 1, 1982.

A current repayment study prepared by BPA to determine the adequacy of existing rates to recover sufficient revenues reveals that BPA needs revenues of $2.4 billion in FY 1983. Current rates would produce revenues of $1.7 billion.

A number of factors account for this increase in BPA's costs. A major portion of the increase can be attributed to escalation in BPA payments for Washington Public Power Supply System (Supply System) nuclear projects. Under a process called net billing, BPA is obligated to cover 100 percent of the costs for projects 1 and 2 and 70 percent of project 3. Interest payments on bonds issued for project 3 will be included in BPA's rates for the first time in FY 1983. Also included in BPA rates will be increased costs of Supply System shared facilities. Projects 4 and 5 were designed to share facilities and costs with projects 1 and 3. Because projects 4 and 5 have been terminated, the full costs of these shared facilities must now be borne by projects 1 and 3. The remainder of the increase in costs attributable to the Supply System is the result of increases in construction costs and interest on bonds for projects 1, 2 and 3.

Also contributing to the need for a revenue increase are increases in the costs of the residential exchange authorized by the Regional Act, BPA's expansion of conservation and renewable resource programs, increased operation and maintenance expenses, and deferred interest payments that must be made to the U.S. Treasury.

BPA implemented substantial wholesale power rate increases in December 1979 and July 1981 and also anticipates increasing its rates in 1983 and 1985. These past and future rate increases, coupled with the proposed 1982 rate increase, could have significant cumulative impacts. Therefore, it was decided that this environmental impact statement should evaluate both the effects of the 1982 increase and the cumulative effects of rate increases occurring or scheduled to occur during the 1979-1985 period. The EIS examines alternative revenue levels and rate designs and assesses their potential impacts if implemented. In addition, mitigation measures for both revenue level and rate design impacts are explored.

B. 1982 Revenue Level Alternatives and Environmental Consequences

1. Description and Comparison of Revenue Level Alternatives

Five basic revenue alternatives are examined in the EIS. These include a no action alternative, the proposed alternative, modification of the proposed alternative, a long run incremental cost (LRIC) alternative, and a phased-in LRIC alternative.

Under the no action alternative, BPA would maintain its existing rate structure, resulting in a revenue deficiency of $731 million, given estimated FY 1983 loads. Consequently, if this alternative were implemented, BPA would be prohibited from meeting its financial obligations, its statutory requirement to be self-financing would be violated, and the shortfall would have to be recovered from future ratepayers.

Revenues derived under the proposed revenue level alternative would be sufficient to meet BPA's FY 1983 revenue requirement and would represent a 43 percent increase over the estimated revenues that would be collected under current rates during FY 1983. This alternative allows BPA to meet all financial obligations and provides that customers receiving service during FY 1983 would pay the full costs incurred during FY 1983 to provide that service.

Several aspects of BPA's repayment analysis could be modified to reduce BPA's revenue requirements. However, these modifications are either outside BPA's current statutory authority, and thus would require Congressional action in order to implement, or would violate current contractual agreements. One way the repayment analysis could be modified would be to eliminate irrigation assistance from BPA's revenue requirement. The effect, however, would be so insignificant that the total revenue requirement for FY 1983 would be virtually unaffected. BPA's repayment process also could be modified by extending the facility amortization period, thereby reducing the proposed increase in the revenue by approximately 2 percent. Finally, if shared costs of Supply System plants 4 and 5 were excluded from the budgets for Plants 1 and 3, BPA's revenue requirement for FY 1983 would decrease by approximately 3 percent.

LRIC or marginal cost based rates would price wholesale power at the projected long run cost of acquiring new power resources in the Pacific Northwest. Rates based on the long run incremental costs developed in BPA's 1982 Time-Differentiated Long Run Incremental Cost Analysis and BPA's projected FY 1983 sales volume would recover revenues of approximately $5.7 billion. These revenues would be approximately 250 percent higher than revenues recovered under the no action revenue alternative and 133 percent higher than revenues received under the proposed alternative.

One method of easing the impact of shifting to LRIC pricing would be to phase in the LRIC rates over a 5-year period. One-fifth of the difference between rates based on the proposed rate level and rates based on the 1982 LRIC Analysis could be added to the proposed rate each year for 5 years. Rates designed in this manner and applied to BPA's projected FY 1983 sales volume would recover revenues of approximately $3.1 billion. This would represent an increase of 90 percent over revenues recovered under the no action alternative and 27 percent over revenues collected under the proposed alternative.

Both the revenue level based on LRIC pricing and that based on graduated LRIC would violate the directive in the Bonneville Project Act that BPA rates be the lowest possible consistent with sound business principles. Potential questions also would be raised as to how excess revenues should be distributed or invested.

2. Environmental Consequences of Alternatives

The alternative revenue levels would have varying effects on the physical and socioeconomic environments. The no action alternative would be expected to have the most negative effect on the physical environment and the most beneficial effect on the socioeconomic environment. The most positive effects on the physical environment and the most negative short-term effects on the socioeconomic environment would occur if the LRIC alternative were implemented. The impacts of the other alternatives would fall within the range defined by the no action and LRIC alternatives. Specific impacts of the modified proposed and phased-in LRIC alternatives are not discussed in the EIS. The impacts of the modified proposed alternative would be close to impacts of the proposed alternative and the impacts of the LRIC and phased-in LRIC alternatives would be similar.

An econometric model that simulates the Pacific Northwest's supply and demand for electricity was used to determine the effect of the no action, proposed, and LRIC revenue levels on demand for electricity. The model projected the effects of rate levels on consumption of energy (including fuels other than electricity) by residential, commercial, and industrial users through the year 2000. Results were used to project effects of the alternatives on various aspects of the socioeconomic and physical environment.

The model projected that regional load requirements in the year 1990 would be 140,991 GWh under the no action alternative, 133,733 GWh under the proposed alternative, 114,652 GWh under the phased-in LRIC alternative, and 114,807 GWh under the LRIC alternative. In the year 2000, regional load would be 194,826 GWh under the no action alternative, 179,366 GWh under the proposed alternative, 145,158 GWh under the phased-in LRIC alternative, and 147,681 under the LRIC alternative.

It is estimated that four-fifths of the reduction in loads would result from price-induced conservation and one-fifth from substitution of other fuels for electricity. In the year 2000, under LRIC pricing of electricity, natural gas consumption is estimated to be approximately 13 percent greater than under the no action alternative, 14 percent greater than under the phased-in LRIC alternative, and about 2 percent greater than under the proposed alternative. Oil consumption in the year 2000 would vary only slightly under the no action, proposed, and LRIC alternatives.

Over time, decreases in growth in electricity load would limit the regional need for new generation resources. The proposed alternative would require about 1,246 fewer megawatts of plant capacity in 1990 and approximately 2,654 fewer in 2000 than would the no action alternative. Difference between demand under the LRIC versus no action the alternative would be approximately 4,495 megawatts in the year 1990 and 8,093 megawatts in the year 2000.

The impact of a BPA wholesale rate increase on retail rates of its preference customers depends on a number of factors including:

(1) the amount of the utility's power obtained from BPA, (2) the utility's total operating costs, and (3) the design of the utility's retail rates.

On the average, the percentage of total utility expenditures associated with the purchase of BPA power under the proposed revenue alternative would be 64 percent for municipal utilities, 72 percent for PUD's, and 63 percent for cooperatives. The LRIC alternative, if fully implemented in 1982, would increase costs of power purchased from BPA on an average of 358 percent for municipal utilities, 383 percent for PUD's, and 315 percent for cooperative utilities.

A BPA revenue level increase would affect rates paid by investor-owned utilities (IOU's) for power purchased from the new resources pool to meet load growth and the retail rates charged to residential and small farm customers of IOU's participating in the IOU/BPA power exchange. The cost of power from BPA's new resource pool would increase 37 percent under the proposed alternative. This increase would not be expected to have a substantial impact on IOU retail rates. The effects of the proposed revenue increase on the retail rates charged to the IOU's residential and small farm customers would be similar to the effects on BPA's preference customers. If BPA were to implement the LRIC revenue alternative and BPA's subsequent rates were to exceed the average system costs of an exchanging utility, the exchange contracts provide that BPA would sell power to the utility at no more than the utility's average system cost.

Pacific Southwest utilities purchase nonfirm energy from BPA and therefore their customers also would be affected by a revenue level increase. The effects are anticipated to be socioeconomic, and the use of nonfirm energy by Southwest utilities is not expected to change. Higher priced nonfirm energy sold to California utilities could reduce demand for electricity and affect employment levels nominally in the manufacturing and small business sectors.

Analyses of the historical relationship of household costs to income level indicate that low-income consumers devote a significantly larger share of their income to energy purchases than other consumers. Low-income consumers, therefore, would be more severely affected by an increase in electricity rates than would higher income consumers.

Historical analyses also reveal that the poor are less able than wealthier consumers to rapidly respond to increasing energy prices by implementing conservation measures. Of the four alternatives, the no action alternative would have the most benefical effect on low-income consumers and the LRIC alternative the most negative impact. If the LRIC alternative were implemented, low-income consumers would be required to drastically alter their lifestyles to live within their income constraints unless measures for mitigating the burden were developed. Both the LRIC and proposed alternatives could pose particularly serious problems for the low-income elderly.

An increase in electricity price generally does not affect the economic viability of business and industry, except when electricity is a major input in production or a business is marginally profitable. Industries for which electricity is a major factor in production include primary metals, mining chemicals, and pulp and paper. In the Pacific Northwest, BPA's direct-service industrial (DSI) customers are the major industries in the these categories.

BPA rates charged to DSI's increased substantially in 1982 to reflect costs of exchange resources used to serve them. Under provisions of the Regional Act, the DSI's are assumed to be served primarily by resources from the exchange pool, which are higher in cost than the resources used to serve priority firm loads. The increase that would be experienced by DSI's under BPA's 1982 proposed revenue level would not be as large as the percentage increase to them in 1981 or the 1982 proposed increase to priority firm customers.

Because production costs of individual DSI's are comparable to similar industries in other regions, BPA's proposed 1982 revenue level increase could cause the DSI's to hasten decisions to either improve plant efficiency or possibly shut down operations entirely. The effect would be positive if industries improved efficiency. However, if plants shut down, negative economic impacts on employment and regional income would result. Implementation of either LRIC revenue alternative could cause substantial plant closures and resulting unemployment and reduced regional income.

In analyzing the socioeonomic and environmental effects of an increase in BPA revenue level, a considerable analytical effort was directed toward analyzing the effects of increased power costs on Pacific Northwest irrigated agriculture. A study commissioned by BPA for the 1979 rate filing of the effects of electric rate increases on Pacific Northwest irrigated agriculture was updated for the 1982 filing to reflect changes that have occurred in the intervening period.

The study revealed that the no action alternative is expected to have the least effect and the LRIC alternative the most severe effect on existing irrigated acreage and irrigation power requirements. Between the years 1990 and 2000, existing irrigated acreage is expected to decrease by less than 1 percent, from 4,057,381 to 4,034,262 acres, and irrigation power requirements by 10 percent under the no action alternative. This decrease is a long run response by irrigators' to prior electricity rate increases. By the year 2000, the proposed alternative is expected to result in withdrawal of approximately 23,000 acres or one-half of one percent more acres of existing irrigated acreage from sprinkler irrigation than if the no action alternative were implemented. Irrigation power requirements would be about 12 percent less under the proposed alternative than under the no action alternative. Implementation of the LRIC alternative would have a more severe impact on existing irrigated agriculture. By the year 2000, under the LRIC alternative, existing irrigated acreage would be 19 percent or 779,000 acres less and resulting power requirements 35 percent less than under the no action alternative.

Development of new irrigated acreage is not expected to differ measurably under the no action and proposed alternatives. Under the LRIC alternative, 400,000 fewer acres would be brought under irrigated agricultural production than under the no action alternative, and power requirements, including diversion losses, would be about 1800 GWh/year less than under the no action alternative.

Regionwide, in the year 2000, farm income would be reduced by an average of $3 per acre under the proposed alternative and $29 per acre under the LRIC alternative. The effects of the alternatives on income would vary by subregion. Farm income in the Mid-Columbia regions would be affected to the greatest degree, decreasing by $10 or more per acre by the year 2000 in response to the proposed revenue level.

The proposed revenue level and particularly the LRIC revenue level could result in some farmers going out of business and some acreage either reverted to dryland agriculture or taken out of production. In contrast to these negative impacts, positive impacts would occur associated with a reduction in the amount of power required for irrigation and in associated avoided diversion losses. By the year 2000, the proposed and LRIC alternatives could result in power requirements for irrigation of 856 GWh's and 3137 GWh's, respectively, less than under the no action alternative.

Effects on the primary physical environment of an increase in BPA revenue level would result primarily from changes in generation requirements and substitution of other fuels for electricity. In evaluating these environmental effects, BPA assumed that the avoided generation would be either coal-fired or nuclear facilities. It is estimated that the change in generation requirements resulting from implementation of the proposed revenue level would eliminate the need for constructing and operating three 500 megawatt coal plants and one 1000 MW nuclear plant. The LRIC alternative would avoid the equivalent effects of eight 500 MW coal plants and four 1000 MW nuclear plants. Elimination of the new generation would avoid accompanying land use, solid waste, water, and air quality impacts associated with mining, processing, and power production. The EIS includes a detailed discussion of the environmental effects of generation avoided under the proposed and LRIC alternatives.

These avoided environmental effects would be somewhat offset by the physical environmental effects resulting from induced increases in use of alternative energy sources. Because of uncertainty about what alternative energy sources would be used as substitutes, quantification of resulting environmental effects is very speculative. However, increased direct fuel usage would occur most significantly in populated areas where air quality problems are more common. Electric generating plants generally are isolated from population centers and are more amenable than direct fuel usage to regulation and to technological means of limiting emissions.

The physical environment also could be affected by the reduction in irrigated acreage anticipated under the proposed and no action alternatives. Water withdrawals, siltation, and pesticide use associated with irrigated farming would decrease as acreage was taken out of production. The resulting benefits could be significant for particular aquatic environments.

The revenue alternatives would not affect the uses and resources of the Columbia River and its tributaries. The use of hydroelectric facilities to meet regional peaking requirements would continue under all of the alternatives. Additional load would be met by development of nonhydroelectric facilities since the hydroelectric capability of the region has essentially been fully developed (from a cost-effective standpoint).

C. Cumulative Revenue Level Alternatives and Environmental Consequences

1. Description and Comparison of Cumulative Revenue Level Alternatives

The EIS examines expected cumulative short and long run consequences of four alternative revenue levels for the 1979 to 1985 period. These alternatives include: (1) a no action alternative; (2) a proposed alternative that incorporates BPA's past revenue level increases, the 1982 proposed increase, and anticipated increases through June 30, 1985; (3) a phased-in LRIC based revenue level alternative, and (4) an LRIC based revenue level alternative.

The no action alternative assumes that BPA rates effected on December 20, 1974, continue in effect from 1979 to 1985. This rate level then is used to project revenue levels and loads in the years 1990 and 2000. Under this alternative, the revenue shortage would increase throughout the period of analysis to the year 2000. Consequently, BPA's statutory requirement to collect revenues sufficient to meet present costs would be violated, BPA's financial solvency would be endangered, and the increasing shortfall would have to be recovered from future ratepayers.

Under the proposed alternative, the rate as of June 30, 1985, is held constant to project revenue levels and loads to the year 2000. This alternative would provide sufficient revenues to meet BPA's cumulative repayment requirements during the 1979-1985 period, would be consistent with BPA's statutory requirements, and would provide rate equity for present and future ratepayers.

The phased-in LRIC alternative with its five year phase in period and the LRIC alternative assume that BPA initiated unconstrained LRIC or marginal cost pricing in 1979 and held the resultant rates constant to the year 2000. The LRIC rates are based on BPA's 1982 Time-Differentiated Long Run Incremental Cost Analysis and resultant revenue level converted to 1979 nominal dollars. If BPA had established unconstrained LRIC based rates in 1979, or phased-in LRIC rates, it would have collected revenues substantially in excess of its costs in that and each subsequent year. This would violate BPA's Congressional directive to promote widespread use of electricity at the lowest possible cost. A mechanism would have to be developed to equitably redistribute the excess revenues to regional ratepayers.

2. Environmental Consequences of Cumulative Alternatives

The environmental consequences of the cumulative no action, proposed, and LRIC alternatives would be similar to, but more pronounced, than the consequences of the corresponding 1982 alternatives because of the cumulative effect of the series of revenue actions.

BPA's energy simulation model also was used to predict the effect of each of the cumulative revenue level alternatives on electricity consumption. The model projected that regional generation requirements in the year 2000 would be 78,803 GWh's less under the cumulative LRIC alternative than under the cumulative no action alternative. Under the cumulative proposed alternative, regional generation requirements would be 46,974 GWh's less than under the cumulative no action alternative.

About one-third of the reduction in load under the proposed and LRIC alternatives would result from conservation and the other two-thirds from the substitution of other fuels for electricity. In the year 2000, natural gas consumption would be approximately 21 percent greater under the LRIC alternative and 9 percent greater under the proposed alternative than under the no action alternative. Oil consumption under the proposed and LRIC alternatives would increase from the levels projected under the no action alternative.

The proposed cumulative revenue level alternatives would cause preference utilities' costs to increase. To maintain financial solvency, utilities would have to increase retail rates substantially. By FY 1984, under the proposed alternative, PUD's on the average would apply 76 percent and municipal utilities and cooperatives would each apply 68 percent of their 1981 revenues toward the purchase of BPA power. The cumulative impact on preference utilities would be most severe under the LRIC alternative.

Under the proposed alternative, BPA's nonfirm energy rate is projected to increase 65 percent between 1979 and 1983. Despite this increase, the costs of BPA nonfirm energy still would be less for Pacific Southwest utilities than costs of alternative thermal power resources.

The cumulative impacts on consumer income groups of the no action, proposed, and LRIC revenue level alternatives would be similar to, only stronger, than those associated with the single 1982 increase. On the average, low-income households would experience a larger proportionate increase in electricity costs over time and would face greater difficulty adapting to the rate increases than would higher income households. The LRIC alternative could have serious cumulative effects on the social and economic well-being of the poor, particularly the low-income elderly.

The analysis of the effects of the cumulative revenue level alternatives on sprinkler irrigated agriculture is limited to effects on existing irrigated agriculture. About 762,000 fewer acres (representing a power requirement of about 5,100 GWh/year) would be under irrigation by the year 2000 under the LRIC alternative than under the no action alternative. Under the proposed alternative, 112,000 fewer acres of currently irrigated land (representing 3,800 GWh/year) would remain under irrigation by the year 2000 than under the no action alternative.

Impacts of the alternatives on net farm income vary by subregion, with the LRIC alternative having a substantially greater impact than the proposed alternative. By the year 2000, the average income reduction for the four states would be \$7.50/acre/year under the proposed alternative and \$29/acre/year under the LRIC alternative. The greatest average per acre income reduction under both the proposed and LRIC alternatives would occur in the State of Washington.

Physical environmental effects of the cumulative revenue level alternatives would be of the same type as those resulting from the 1982 revenue levels, but more pronounced. It is assumed that the decrease in generation requirements that would result by the year 2000 if the proposed alternative were implemented would be equal to eight 500 MW coal-fired and four 1,000 MW nuclear facilities. The LRIC alternative could avoid generation equal to thirteen 500 MW coal-fired and six 1,000 MW nuclear facilities. By eliminating this new generation, accompanying land use, solid waste, water,and air quality impacts could be avoided. Although these impacts would be avoided, other adverse environmental impacts would result as consumers increased their use of alternative energy sources.

The cumulative effects of the proposed or LRIC revenue level alternatives are not expected to affect the use and resources of the Columbia River and its tributaries. Effects on the physical environment from the reduction in irrigated acreage would be positive.

D. Rate Design Alternatives and Environmental Consequences

In developing proposed rates, BPA considered a variety of rate design alternatives. The EIS discusses alternatives to BPA's proposed rate schedules for priority firm power, industrial firm power, new resources firm power, nonfirm energy and wholesale firm capacity. Alternatives to BPA's proposed emergency capacity rate, surplus firm power rate, firm energy rate, reserve power rate, special industrial rate, surplus firm energy rate, and energy broker rate are not examined in the EIS because it is not anticipated that revenues from sales under these rates will be significant or that the rates will have significant environmental effects.

The priority firm rate schedule applies to sale of firm power for use within the Pacific Northwest by public bodies, cooperatives, and Federal agencies and by IOU's participating in the residential and small farm exchange under Section 5(c) of the Regional Act. Both the existing and proposed rate schedules contain a demand charge that is seasonally and diurnally differentiated and an energy charge that is seasonally differentiated to reflect the fact that costs of providing power vary by season, day of the week, and hour of the day. The time periods are the same under both the proposed and existing priority firm rate.

One of the alternatives to the proposed and existing uniformly applied firm power rate is a "tiered rate" approach that involves the application of different rates to specific blocks of customer electricity consumption. For example, the initial blocks of consumption would be charged a lower price than subsequent blocks. Significant analyses were conducted regarding the mechanics by which BPA might implement tiered rates, the potential effects that tiering could have on BPA's revenue stability, and the impacts that tiered rates might have on BPA customers. Tiered rates were excluded from the rate proposal because of unresolved concerns over their effects on BPA's revenue stability, variations in customer power costs, and the potential that they may serve a function already addressed by BPA's billing credits program.

The second alternative firm power rate considered was a rate based on the "inverse elasticity" principle. Under the inverse elasticity approach, customers most responsive (highly elastic) to an increase in the cost of electricity would be charged rates closer to incremental cost than those rates charged less elastic customers. The availability of reliable elasticity estimates for BPA's customer classes hinder employment of this approach.

The goal of both the tiered and inverse elasticity approaches would be to increase efficiency of electricity use. Therefore, these designs may have the potential to lessen the overall negative socioeconomic impact of increasing rates.

The seasonally differentiated feature of the proposed rates could encourage a consumption pattern that permits more efficient operation of the Federal Columbia River Power System (FCRPS), thereby minimizing further need for construction of additional generating facilities. Therefore, the negative physical and socioeconomic impacts related to construction and financing of additional facilities could be postponed or avoided.

Seasonal differentiation is of benefit to irrigators and may encourage continued growth of irrigated agriculture. Whereas the resulting socioeconomic effect would be positive, negative effects on the physical environmnent could result from increased silt, pesticide, and fertilizer runoff into rivers and changes in land use.

The diurnally differentiated demand charge in the proposed rate could discourage consumption during peak periods and decrease the need for construction of additional peaking capacity. Positive physical environmental effects would be associated with decreased construction of peaking facilities.

The firm capacity rate schedule applies to capacity sales to utilities on a contract year and/or seasonal basis. Energy associated with the delivery of capacity is returned to BPA.

To encourage capacity purchasers to limit use of Federal generating facilities, both the existing and proposed firm capacity rate schedules include a provision for an additional monthly charge if capacity use is in excess of 9 hours per day. Alternatives to the variable capacity rate were also considered, including a fixed rate that would provide no incentive to limit the duration of capacity purchases and a time-differentiated rate that would be higher during peak than offpeak hours.

Both the proposed firm capacity rate and the time-differentiated capacity rate would encourage consumption patterns that permit efficient operation of the FCRPS. Therefore, future need for construction of additional peaking facilities would be minimized. The fixed rate could result in the need for construction of additional peaking capacity and the negative physical and socioeconomic impacts related to construction and financing of these facilities.

The new resources rate schedule applies to purchases of firm power for resale or direct consumption by purchasers other than direct-service industrial customers. Power is purchased under the new resources rate schedule by IOU's to serve their firm power deficits incurred prior to December 5, 1980, and by public bodies and cooperatives to serve new large single loads.

The proposed new resources rate has been designed to eliminate some of the problems associated with the existing rate, which was based on an averaging of the energy costs of all new resources acquired by BPA. No purchases were made under the existing rate because the energy charge was too high. It is proposed that the new resources rate be equal to a base rate based on lowest cost resources assigned to serve the new resources load. This base rate would apply until purchases exceeded the annual average output of the lowest cost resources. Thereafter, the rate would increase as the IOU requirements load increased and BPA had to purchase additional resources to serve the load.

One alternative to the proposed new resources rate schedule would be a rate schedule similar to the existing rate. This, however, would create the same problems as the existing rate.

A second alternative would be to include two levelized rates in the rate schedule. The first level would reflect the lowest cost resources currently assigned to serve the new resources firm loads. The second level would reflect costs of BPA's most costly new resources, the output of which would be marketed as surplus power. However, this alternative would be unsatisfactory for two reasons. The amount of power purchased under the first level would exceed the capability of the lowest cost new resources, creating an underrecovery of revenue. In addition, the surplus power marketed under the second rate level would be so expensive there would be no market for it.

Although the environmental consequences of the alternatives would vary slightly, none would have more than a minor effect on the environment.

The nonfirm energy rate is for purchase of nonfirm energy both inside and outside the Pacific Northwest. The existing nonfirm energy rate is based on operational considerations and allows BPA a flexibility in setting a charge that responds to market and water conditions. The proposed nonfirm rate structure provides less flexibility for BPA but offers its customers greater predictability and ease of understanding. The proposed rate schedule is composed of (1) a standard rate in effect at all times except when a spill or imminent spill condition exists, (2) a spill rate, and (3) an incremental rate applied to sales of power produced or purchased concurrently with the nonfirm sale.

Alternatives to the proposed rate schedule include an alternative similar to the existing schedule, a share-the-savings rate similar to BPA's 1979 nonfirm energy rate, and a flat rate. The proposed and existing alternatives would allow BPA the greatest flexibility in responding to water and market conditions. This flexibility could conceivably influence the physical and socioeconomic environments. The share-the-savings alternative was designed to displace high cost thermal resources and therefore could result in a reduction of environmental impacts associated with generation. The flat rate would offer BPA no flexibility to respond to water and market conditions and if set too high could discourage purchases of nonfirm energy, resulting in less displacement of thermal resources and increased pollution levels associated with thermal generation.

The industrial firm and modified firm power rate schedule applies to sales of Federal power to BPA's direct-sevice industrial customers. Two versions of the rate schedule are offered to DSI customers to allow for billing differences associated with industrial firm and modified firm contracts available to these customers. The demand and energy charges are time differentiated similarly to those in the priority firm schedule.

Both the existing industrial firm rate and the industrial firm portion of the proposed rate reflect a value of reserves credit that recognizes the value of reserves provided by BPA rights to interrupt DSI load. The credit was calculated differently for the existing rate than for the proposed rate. The credit applied to the existing rate was $76 million and the credit applied to the proposed rate is equal to $62.5 million.

A provision has been added to the proposed industrial and modified firm power rate schedule to establish a minimum bill in order to stabilize BPA revenues. This provision is not included in the existing rate.

There are a number of alternative ways the industrial rate schedule could be designed. Compensation to the DSI's associated with restriction rights could be eliminated or the DSI's could be provided a different amount of compensation. In addition, variations could be employed in the method for applying the credit. Whereas, the proposed method involves granting a credit against the charge for each kilowatthour purchased by the DSI's, an alternative would be to apply the credit only when, and to the extent which, BPA exercised its restriction rights. This approach could create cash flow problems for BPA and it fails to reflect the fact that reserves are of benefit whether used or not. Other alternatives include implementation of a tiered rate structure and elimination of the minimum bill provision. These both could create revenue stability problems.

The environmental consequences of these alternatives would be related to their effect on DSI rate level. Higher rates would reduce impacts created by operations and operation of generation resources to serve the DSI's.

A special industrial power rate schedule was implemented in BPA's 1981 rate filing to serve Hanna Nickel Smelting Company and BPA again has developed a special industrial rate for Hanna. The Regional Act allows the Administrator to establish a special rate that need not be cost based, if any direct service industrial customer using raw materials indigenous to the region would suffer adverse impacts of increased rates pursuant to the Regional Act and if all power sold to such a customer could be interrupted or withdrawn to meet firm loads in the region.

The existing and proposed rates would avoid the adverse impacts on Hanna and its employees that would result if BPA were to apply its industrial rates to Hanna. Employment levels would be maintained in an isolated part of the region without transferring significant cost to the remaining ratepayers.

BPA is proposing to offer three new rate schedules. They include an Energy Broker Rate, surplus firm power rate, and surplus firm energy rate.

The Energy Broker Rate schedule applies to energy sold through the Western Systems Coordinating Council's energy broker program. BPA will use the broker for energy sales only after all available markets have been served under the nonfirm energy rate schedule. The proposed rate would insure maximum efficiency in the marketing and use of available generation resources. To the extent it allows energy to be marketed that otherwise would be spilled, it avoids adverse environmental impacts associated with spilling.

The surplus firm power rate schedule was created to sell any surplus firm power resulting from DSI load curtailments, priority firm load underruns, or over forecasting of IOU net requirements under 7(f). Revenues from the surplus firm power sales would reduce the revenue required from BPA customers. Resulting positive socioeconomic impacts would be offset by negative impacts on the physical environment resulting from operation of surplus resources.

The surplus firm energy rate schedule was established to market surplus firm energy. It is not expected to cause significant environmental impacts.

The design of BPA's proposed reserve power, emergency capacity, and firm energy rate schedules is the same as the design of the existing schedules. It is not anticipated that these rates would significantly affect the physical or socioeconomic environment.

E. Mitigating Measures

Mitigating measures could be applied by various entities to reduce the severity of adverse effects of an increase in wholesale rates. These measures include existing and proposed conservation programs offered by BPA.

BPA offered in FY 1981 and FY 1982 and is planning to offer in FY 1983 energy conservation programs through its utility customers to residential, business, and industrial consumers. Conservation programs targeted for residential consumers are designed to decrease electricity used for space and water heating. Commercial and industrial consumers are being offered energy audits and programs that would help them conserve electricity used in industrial processes, lighting, and water heating.

BPA also is implementing or plans to implement energy conservation programs for other consumers in the Pacific Northwest, including technical assistance to State and local governments, energy conservation audits and installation of conservation measures in institutional buildings, and efficiency improvements for the transmission and distribution systems of regional utilities.

F. Areas of Controversy

Certain issues addressed in the EIS pertaining to 1982 revenue level, cumulative revenue level, and rate design have generated significant controversy.

Concern has been raised throughout the region over the magnitude of the proposed revenue level increase. It has been suggested that adjustments, including exclusion of certain costs, should be made in the Repayment Study to lower the revenue increase needed. It also has been suggested that revenue level should be set to encourage efficient use of resources, rather than to meet financial obligations and provide rates that are as low as possible to consumers. In particular, the issue of LRIC pricing or phased-in LRIC pricing has received considerable attention.

Although impact of a revenue level increase on all customer groups is of concern, particular concern has arisen about the impacts on low-income consumers and irrigated agriculture and whether these impacts should be mitigated. The impact of rate increases implemented or anticipated to be implemented during the 1979-1985 period has been the subject of considerable controversy and therefore a portion of the EIS is devoted to discussing these impacts.

Attention also has been drawn to particular rate design issues, including design of the nonfirm rate and determination of the value of reserves credit applied to industrial and modified firm power rates. Significant controversy has arisen over the issue of "tiered rates" or the application of different rates to specific blocks of consumption.

G. Issues to be Resolved and Choices Among Alternatives

In order to develop proposed rates, it was necessary for BPA to examine and resolve a number of issues related to revenue level, rate design, and impacts. In resolving the issues and developing the rates, BPA considered a variety of objectives, including among others, statutory requirements, environmental impacts, equity, and efficient use of resources. Although all these objectives were taken into account, statutory requirements were an overriding consideration.

For purposes of evaluating impacts, 1982 revenue level alternatives considered in the EIS were limited to five: no action, proposed, modified proposed, LRIC, and phased-in LRIC. Three cumulative revenue level alternatives were analyzed, including a no action alternative, proposed alternative, and LRIC alternative.

BPA believes that the proposed 1982 revenue level and cumulative revenue level are the most reasonable choices among the alternatives explored. The proposed 1982 and cumulative revenue levels meet BPA's statutory requirements, meet all of BPA's required financial obligations, and achieve rate equity in that customers receiving service during the period pay the full costs incurred during the period to provide the service. It is difficult to determine which of the revenue level alternatives would be most desirable from an environmental standpoint because the alternatives that have the most positive effect on the physical environment have the most negative effect on the socioeconomic environment and vice versa. Impacts of the proposed alternatives fall between these two extremes.

Although the EIS did consider effects of the revenue level increase on low-income consumers and irrigated agriculture, it was not recommended that revenue level or rate design be altered in an effort to mitigate these impacts. Various conservation programs offered by BPA may help alleviate adverse impacts consumers would experience from increased rates.

BPA believes that its proposed rate design alternatives represent the most reasonable alternatives, given its rate design objectives. One of the major rate design issues raised concerned the implementation of tiered rates. There are several reasons why BPA is not proposing that tiered rates be established. They could affect revenue stability, cause inequities among BPA customers, fail to be effective if not passed through to consumers in retail rates, and could duplicate the billing credit function.

H. Appeal Process From Administrator's Record of Decision

The Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) established by statute a formal, internal appeal process that allows other agencies, and the public, to appeal from the Administrator's Record of Decision on BPA's 1982 Wholesale Power Rates. Therefore, this final Environmental Impact Statement (EIS) that accompanies the Administrator's Record of Decision falls within the exception to the rule set out in 40 C.F.R. § 1506.10 (1981), requiring notice of a final Environmental Impact Statement to be published in the Federal Register by the Environmental Protection Agency thirty (30) days before a decision can be made on the proposed action.

The rates established by the Administrator's Record of Decision will only become effective upon confirmation and approval by the Federal Energy Regulatory Commission (FERC). 16 U.S.C. § 839e(a)(2). The Regional Act provides that BPA rates are only effective upon a finding by FERC:

> ". . . that such rates -
>
> are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs,
>
> are based upon the Administrator's total system cost, and
>
> insofar as transmission rates are concerned, equitably allocate the costs of the Federal Transmission System between Federal and non-Federal power utilizing such system." 16 U.S.C. § 839e(a)(2).

FERC review under the three enumerated standards of the Regional Act provides interested members of the public and governmental agencies with a real opportunity to alter the Administrator's rates decision. This review process is internal within the Department of Energy. The Department of Energy Organization Act of 1977, P.L. 95-91, established that both the FERC and Bonneville Power Administration are within the Department of Energy.

FERC regulations provide other agencies, and the public, with an opportunity to protest or intervene in final confirmation and approval proceedings concerning BPA rates. "Confirmation and Approval of Rates of Bonneville Power Administration", 46 Fed.Reg. 60613 (1981) (to be codified at 18 C.F.R. § 300.10(a)(4)). FERC general regulations provide that:

> "A petition to intervene may be filed by any person claiming a right to intervene or an interest of such nature that intervention is necessary or appropriate to the administration of the statute under which the proceeding is brought." 18 C.F.R. § 1.8(b) (1981).

Members of the public seeking to intervene in the proceeding before FERC can establish the right to intervene by asserting:

1. A right conferred by statute of the United States; or

2. An interest which may be directly affected and which is not adequately represented by existing parties, if the petitioners may be bound by the Commission's action in the proceeding; or

3. Any other interest of such nature that petitioners' participation <u>may be in the public interest</u>. 18 C.F.R. § 1.8(b). (Emphasis added).

These FERC intervention regulations grant the public broad rights to intervene and make their views known concerning final confirmation and approval of BPA's rates.

Not only will the Administrator's rates decision only become final upon confirmation and approval by the FERC, but only the FERC has authority to approve on an interim basis the rates submitted by the Administrator. 16 U.S.C. § 839e(i)(6). FERC can approve, or disapprove, the final rates submitted by the Administrator on an interim basis, pending FERC's final confirmation and approval in accordance with the Regional Act. 16 U.S.C. § 839e(i)(6). FERC regulations governing interim acceptance and review of BPA rates explicitly provides that:

> ". . . the Commission may take any of the following actions, based on an evaluation of the application:
>
> (1) Order the rate schedule into effect on an interim basis, effective on the date requested by the Administrator or at such time as the Commission may otherwise order;
>
> (2) Deny the Administrator's interim rate request and

reject the application, if the Commission determines that the Administrator's application is:

(i) Patently deficient with respect to the filing requirements of this Part; or

(ii) Fails to comply with the applicable provisions of the Pacific Northwest Electric Power Planning and Conservation Act; or

(3) Deny the Administrator's interim rate request and review the application for final confirmation and approval of the rate schedule pursuant to the provisions of this part." "Confirmation and Approval of the Rates of the Bonneville Power Administration," 46 Fed.Reg. 60613 (1981) (to be codified at 18 C.F.R. § 300.20(b).

If the Commission places a rate schedule filed by the Administrator into effect on an interim basis, such rates are subject to refund with interest. Supra, 18 C.F.R. § 300.20(c). FERC regulations further provide that a notice of any action taken by FERC concerning the Administrator's request for interim rate acceptance will be published in the Federal Register and will be mailed to any interested persons identified in the Administrator's filing. Supra, 18 C.F.R. § 300.20(d). The list of interested persons identified by the Administrator includes all parties to the 1982 Wholesale Power Rate proceeding and all persons that have expressed an interest to BPA in its ratemaking proceedings and have supplied BPA with their addresses.

Any members of the public who desire to be intervenors before FERC in the final confirmation and review process, or the interim approval proceeding, must file a timely petition to intervene with FERC. The timing for filing such a petition to intervene will be triggered by the FERC publishing a Notice in the Federal Register of BPA's request for final confirmation and approval and interim approval. For exact time deadlines and contents of petitions, consult FERC's general regulations governing petitions to intervene, found at 18 C.F.R. § 1.8 (1981).

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IV. Purpose and Need

A. Summary of BPA Authority

Bonneville Power Administration (BPA), an agency of the U.S. Department of Energy, is the marketing agent for the power produced from the Federal Columbia River Power System (FCRPS). The FCRPS consists of the hydroelectric generating projects constructed and operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. BPA also purchases capability necessary to meet its load obligations from thermal generating plants constructed by other entities, such as municipal electric utilities and joint operating agencies. BPA melds (blends) the costs of the thermal and hydro power, and markets this power on a wholesale basis to electric utilities, other Federal agencies, and a limited number of large industrial customers. In addition, BPA constructs and operates an electric transmission system, and transmits (wheels) power over these facilities for other entities.

BPA's major responsibilities, including establishing the rates to be charged to BPA's customers, are embodied in three pieces of Congressional legislation: Bonneville Project Act of 1937, Federal Columbia River Transmission System Act of 1974 (Transmission System Act), and Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Regional Act). While a number of other Acts and agreements influence BPA operations, these three Acts are central to BPA's mission. The Bonneville Project Act established the agency and instructed BPA to set rates to recover all the costs associated with production, acquisition, and transmission of electric power and to recover the Federal investment in the FCRPS. This Act directs that the rates be designed to ". . . encourage the widest diversified use of electric energy" at the ". . . lowest possible rate . . . consistent with sound business principles." The Bonneville Project Act also requires that BPA review the adequacy of its power rates at least every five years and, if necessary, adjust them equitably.

The Transmission System Act placed BPA on a self-financing basis; that is, BPA receives no appropriations from Congress and must pay all operating expenses with revenues collected from its rates. BPA is authorized to sell bonds to the U.S. Treasury to finance construction of new transmission facilities and to fund conservation and other programs.

The Regional Act reaffirmed the above directives and expanded BPA's responsibilities, requiring changes in the process for determining the substance of BPA's rates. Prior to the Regional Act, BPA allocated costs of resources from a single pool of resources which included the hydroelectric facilities comprising the FCRPS, a portion of the Trojan Nuclear Plant, the Hanford New Process Reactor, and three net billed nuclear plants being constructed by the Washington Public Power Supply System. BPA's rates were designed to recover all costs associated with what are now referred to as Federal base system resources. This included the cost of operating and maintaining the FCRPS, the cost of purchase power, the cost of interest on and amortization of the Federal investment in the system, and the cost of repaying that portion of the construction costs at Federal reclamation projects that are beyond the repayment ability of irrigators and have been assigned by law to commercial power revenues. 1/

From a single pool program, the Regional Act, in 1980, created three distinct resource pools and expanded BPA's service to all customer classes in the region. The first resource pool, the Federal base system is defined by the Regional Act to include the FCRPS hydroelectric projects, the resources acquired by the Administrator under long term contracts in force on December 5, 1980, and any resources acquired to replace any reduction in capability of the above resources.

The second resource pool consists of the power purchased under the residential exchange. The Regional Act created this exchange to benefit the residential and small farm consumers in the region. Under the exchange program, BPA is to purchase from utilities wishing to participate in the exchange, an amount of power equal to a prescribed portion of their residential and small farm loads at the utilities' average system costs. 2/ BPA then sells an equal amount of power to the exchanging utilities at the rate BPA charges its preference customers. Any cost reduction resulting from this exchange is to be passed through to the utilities' residential and small farm consumers.

The third resource pool, the new resource pool, includes all new resources that are developed, purchased, or otherwise acquired by BPA.

The costs of each resource pool are to be allocated to particular classes of customers as specified by the Regional Act. The Federal base system resources are to serve BPA's preference customers and the residential and small farm loads of the exchanging utilities. If the Federal base system resources are insufficient to meet these loads, the exchange resource pool would be combined with the Federal base system resources to serve the loads. This situation is projected to occur for a number of months in FY 1983. Should the preference customers and residential and small farm loads exceed the Federal base system and exchange resource pools, resources from the new resource pool would be added to meet these loads. If the Federal base system resource pool is larger than the sum of the preference customer, federal agency and residential exchange loads, the excess could be used to supply DSI loads.

Prior to July 1, 1985, the direct-service industrial customers (DSI's) are to receive power from the exchange resource pool. For FY 1983, the DSI's loads are projected to be smaller than the exchange resources. Until July 1, 1985, if the DSI's loads cannot be fuly met by the exchange resource pool, the new resources pool is to be used to meet this additional need.

BPA's remaining obligations include the following: load growth of the IOU's; any IOU firm power deficits in the year prior to December 5, 1980, that BPA is requested to meet; and new large single loads of BPA's public body, cooperative, and Federal agency customers. These are to be served by BPA's remaining resources, including new resources, after the above needs are met. In FY 1983, BPA anticipates that these loads will be served by a portion of the exchange resources and new resources pools.

B. Rate Development Process

To determine the adequacy of the existing rates to recover revenues sufficient to meet BPA's financial obligations, a repayment study is undertaken. The repayment study determines BPA's total annual repayment requirement. The results of the repayment study are then compared to a forecast of the revenues expected to be derived from the existing rates. If expected revenues are not sufficient to meet BPA's repayment requirement, revisions to the rates become necessary.

Once the repayment study has been completed and the need for revised rates is determined, BPA conducts a cost-of-service analysis. The purpose of the cost-of-service analysis is to identify the costs associated with each class of service. From these allocations of costs, the specific rates are designed to collect the necessary revenues given average water conditions.

In some cases adjustments are made to the cost allocations assigned to each class of service during the rate development process. Because the cost-of-service analysis does not allocate costs from some classes of service or include additional statutory requirements, a separate process is required to adjust the cost-of-service derived cost allocations to reflect the additional requirements, costs, and services. These adjustments include treatment of revenue deficiencies related to fixed contracts, costs and revenues associated with the capacity/energy exchange, the value of reserves provided by direct-service industrial customers, excess revenues from nonfirm sales, equalization of demand charges, and the low density discount for certain utilities. Many of the adjustments made during the rate design process are intended to reflect the results of other rate design studies and concepts.

The basic rate design objectives BPA follows in preparing the rates include: (1) revenues must be adequate to meet repayment obligations; (2) revenue requirements must be met with the burden distributed in an equitable manner among recipients of the service; (3) rates should be designed to encourage conservation and to minimize environmental impact; and (4) rates should be designed to encourage efficient use of the power system by reflecting costs incurred and benefits received. Other factors given consideration include: rate continuity, ease of administration, revenue stability, and ease of understanding.

C. Need for Action

The repayment study conducted for the 1982 rate proposal indicates a need to increase wholesale power rates to enable BPA to meet its FY 1983 financial obligations. This current repayment study finds that BPA needs revenues of $2.440 billion in FY 1983. Revenue during FY 1983 under current rates would amount to $1.709 billion based on forecast FY 1983 loads. Without a rate increase BPA would expect to incur a deficit of about $731 million.

Approximately $477.6 million of the required revenue increase is attributable to increased investment costs of the Washington Public Power

Supply System (Supply System) nuclear projects 1, 2 and 3. Under net billing agreements, BPA is obligated to cover 100 percent of the costs for projects 1 and 2, and 70 percent of project 3. Of the $477.6 million in increased Supply System costs, $207.2 million is debt service for project 3, and has been included for the first time in calculating BPA's total costs. Another new cost associated with the Supply System is the increased cost of shared facilities resulting from the termination of projects 4 and 5. These projects were originally designed to share facilities and costs with projects 1 and 3. However, since projects 4 and 5 have been terminated, the full cost of these shared facilitites must now be borne alone by projects 1 and 3. The amount of this increase in shared facilities cost for projects 1 and 3 is not possible to determine precisely at this time due to uncertainty associated with interest rate levels and other economic factors. Finally, Washington State's Initiative 394, which requires voter approval of new bond issues for the Supply System projects after July 1, 1982 is an additional factor which is difficult to measure. The remainder of the increase in costs attributable to the Supply System ($270.4 million) is the result of debt service on bonds at higher interest rates and higher plant costs on projects 1 and 2.

The costs of the residential exchange authorized by the Regional Act are increasing, resulting in $249.4 million of BPA's increased revenue requirement. The Regional Act provided that BPA increase its service to exchanging utilities from 60 to 70 percent of the exchanging utilities residential and small farm loads beginning July 1, 1982. In addition, several publicly owned utilities have chosen to participate in the exchange because their average system cost is higher than BPA's rate. This contributes to the increased revenue requirement for the exchange. The projected increase in the average system cost of the exchanging IOU's also adds to the increased exchange costs.

BPA's expansion of conservation programs, as mandated by the Regional Act, accounts for $51.5 million of the increased revenue requirement. The expansion includes conservation programs in the residential and commercial sectors as well as programs focused on institutional buildings, industries, and state and local governments.

Approximately $68.2 million is increased operation and maintenance expenses for BPA, Corps of Engineers, and Bureau of Reclamation projects. In addition, $70.2 million is increased annual interest expense required to be paid to the U.S. Treasury for investments made in the FCRPS.

In the recent past, rapidly escalating costs have prevented BPA from making sufficient interest payments to the Treasury. Consequently, BPA estimates that by the end of FY 1982 it will have deferred payyment of $226 million of accrued interest. It is imperative that BPA make payments to repay this deferred interest. Therefore, in FY 1983 that portion of the revenue requirement associated with deferred interest will increase by $32.5 million. The total FY 1983 deferred interest cost will be $197.3 million. Based on this total payment, and FY 1983 payments in FY 1984 and FY 1985, BPA is planning to pay completely the deferred interest and to continue amortization payments such that by the end of FY 1985, BPA will have made sufficient payments to the Treasury to cover the deferral plus an amount of amortization that would have been made in absence of the interest deferral.

Offsetting these increases in the revenue requirement are a decrease of $88.7 million in costs for short term resource acquisitions and power purchases and an increase in revenue of $129.7 million due to forecast increases in sales in FY 1983.

These factors are the primary reasons that require BPA to increase its wholesale power rates for FY 1983 to collect sufficient revenues to meet its current financial obligations.

D. Responsibilities under the National Environmental Policy Act of 1969 (NEPA)

BPA is conducting this environmental impact analysis in order to comply with the requirement, established by the National Environment Policy Act of 1969, that environmental impact analyses be performed prior to arriving at decisions on major Federal actions which have the potential to significantly impact the environment.

BPA implemented wholesale power rate increases on December 20, 1979, and July 1, 1981, for its customers. Based on estimates of the future escalation in costs, BPA anticipates increases to its wholesale power rates in 1983 and 1985. These past and projected rate increases, taken together with the proposed 1982 rate increase, cause BPA to believe that the cumulative impact of the 1979-85 increases should be the subject of environmental analysis. Thus, BPA chose to conduct this environmental impact statement to examine both the effects of the 1982 increase and the cumulative effect of past and projected increases scheduled to occur during the 1979-85 period.

E. Implementation Schedule

BPA's power sales contracts allow for either annual rate reviews with revised rates becoming effective on July 1st or revised rates upon 9 months notice. At BPA's request, its customers agreed to approve contract amendments allowing for a rate adjustment effective October 1, 1982. If approved by the Federal Energy Regulatory Commission (FERC) on an interim basis the proposed rates that are the subject of this EIS would take effect on October 1, 1982.

FOOTNOTES

1/ For a more detailed description of the repayment criteria in effect prior to the Regional Act see Final Environmental Impact Statement, Bonneville Power Administration, 1979 Wholesale Rate Increase, U.S. Department of Energy (DOE/EIS-0031-F), October 1979, pp. II-6 to 7.

2/ For a detailed discussion of the methodology for determining a utility's average system cost see Administrator's Record of Decision, Average System Cost Methodology, Bonneville Power Administration, U.S. Department of Energy, August 1981.

NOTES

V. Comparative Discussion of the Alternatives

A. Introduction

This section of the statement presents the description of BPA's existing rates, proposed rates and reasonable alternative wholesale rate actions, and a comparative analysis of the environmental consequences of each. The purpose here is to summarize the alternatives and their expected environmental consequences in a manner that allows the decisionmaker and the public a basis on which to evaluate the comparative environmental merits of the alternatives. The analytical procedures used to identify the environmental consequences of the alternatives are presented in more detail in the Environmental Consequences chapter of this statement (Chapter VII).

The development of wholesale power rates involves two levels of decisions: (1) the revenue level needed to meet BPA's repayment requirement and (2) the structure of the rate design to achieve that revenue level. Each level of decision requires a choice among alternatives. Therefore, this discussion of alternatives is divided into sections addressing alternative revenue levels and alternative rate designs, both for implementation in 1982.

In addition, the Council on Environmental Quality (CEQ) Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act instruct that the scope of an agency's environmental analysis include cumulative actions and their cumulative impacts (40 CFR 1508.25). In this regard, BPA implemented wholesale rate increases on December 20, 1979 and July 1, 1981, respectively, for BPA's customers. 1/ BPA also foresees rate increases in October 1983 and July 1985, as well as this proposed increase for October 1982. Thus, consistent with the CEQ requirement to address cumulative actions and impacts, this statement will address alternative cumulative effects of BPA's 1979 and 1981 rate increases as well as the impacts of the proposed 1982 increase and the anticipated October 1983 increase. BPA currently does not have sufficiently reliable projections of the July 1985 increase to permit a valid analysis of its impacts.

In order to provide clarity in the analysis of alternatives, this section of the statement has been organized into three distinct discussions: (1) alternative revenue levels for 1982, (2) alternative cumulative 1979-1985 revenue levels, and (3) alternative rate designs for the 1982 rate proposal. The discussions of alternative revenue levels are further subdivided into descriptions of the alternative revenue levels including the no action (existing) and proposed alternatives, comparisons of the revenue and environmental consequences of the alternatives, and a matrix summarizing the consequences of the alternatives. The discussion of rate design alternatives for the 1982 increase is subdivided by the particular rates into a description of the existing rate, the proposed rate, alternative rate designs, and a comparison of the consequences of all alternatives.

B. Alternative Revenue Levels for FY 1983

This section describes and compares the consequences of several alternative revenue levels, including BPA's proposed revenue level, for an

October 1982 rate increase (i.e., for the rates which will be in effect during FY 1983). While some of the alternatives discussed are outside the agency's statutory authority, they are reasonable alternatives as defined by the CEQ regulations and their examination provides comparative information on the consequences of a revenue increase. The five alternatives considered are: (1) No Action Alternative, (2) Proposed Alternative; (3) Modified Proposed Alternative; (4) Long Run Incremental Cost Alternative; and (5) Phased-In Long Run Incremental Cost Alternative.

1. Description of Revenue Level Alternatives

a. No Action Alternative

Under the no action alternative, BPA would maintain its present rate structure (rates effective on an interim basis as of July 1, 1981) resulting in a forecast revenue level of $1.709 billion given estimated FY 1983 loads. This compares to BPA's revenue needs identified by a repayment study for the test year (FY 1983) of approximately $2.4 billion. 2/

b. Proposed Alternative

The proposed revenue alternative would collect revenues sufficient to meet BPA's FY 1983 revenue requirement of $2.4 billion. This would be an overall revenue increase of 51 percent over the estimated revenue that would be collected under the present rates during the test year. Since specific revenue increase impacts on individual customers or customer classes also reflect rate design actions, the individual increase to a customer class may be somewhat different than the overall percentage increase.

c. Modification of Proposed Alternative

There are several aspects of BPA's repayment analysis that could be altered, thereby yielding different revenue requirements. Most of these repayment revisions have been addressed at greater length previously in BPA's Final Environmental Impact Statement, 1979 Wholesale Rate Increase, Chapter III(B) and (C), and the Final Environmental Assessment, 1981 Rate Proposal, Chapter II(A)(2).

(1) Exclusion of Irrigation Assistance

BPA is presently obligated by statute to repay that portion of the construction costs of Federal reclamation projects which exceeds the repayment ability of the irrigators. If this irrigation assistance were eliminated from BPA's revenue requirement, total revenues would be virtually uneffected for FY 1983.

(2) Extend Facility Amortization Period

BPA currently amortizes transmission facilities over a 35-year period and hydroelectric generation plant over a 50-year period. This amortization tends to be "lumpy" in that investments need not be amortized in fixed yearly increments but rather need be amortized only by the end of the respective 35- or 50-year period. It has been argued that generation plant amortization should be extended to 85 years, as this period more closely corresponds to the actual service life of hydro facilities. If this change were incorporated into BPA's repayment policy, the proposed revenue increase could be reduced by approximately 2 percent.

(3) Exclude Transferred Share Costs of Washington Public Power Supply System Plants 4 and 5 from Plants 1 and 3

Supply System Plants 1 and 4, and 3 and 5 were designed to share common facilities such as cooling towers, access roads, etc., and thus share the costs of these facilities. Upon the termination of Plants 4 and 5, the costs of the shared facilities that are essential to the operation of Plants 1 and 3 could no longer be shared. The total costs of these shared facilities now have been assigned to the budgets for Plants 1 and 3. Under BPA's net-billing agreements with the Supply System, BPA is obligated to pay 100 percent of the costs of Plant 1 and 70 percent of Plant 3. The transfer of the costs of the shared facilities increases BPA's revenue requirement for FY 1983 by approximately 3 percent.

d. Long Run Incremental Cost (LRIC) Alternative

LRIC, or marginal cost based rates, would price wholesale power at the projected long run cost of acquiring new power resources in the Pacific Northwest. Economic theory suggests that rates based on marginal costs would represent the real cost or value of providing additional power and would provide accurate price signals to consumers. In theory, under certain assumptions and with a given income distribution, marginal cost pricing would achieve efficient resource allocation and the optimal consumer power consumption decisions. This conclusion is based on the assumption that all substitute goods also are priced at marginal cost. In the Pacific Northwest, the primary substitutes for electricity are natural gas, fuel oil, wood, and various conservation measures, and to a much lesser extent, coal and renewables other than wood.

BPA has completed an updated LRIC Analysis as part of its 1982 rate development process. The results of this study indicate marginal costs of $59.94 kW/yr for capacity and 42.43 mills per kilowatthour for energy (see BPA's 1982 LRIC Analysis for the derivation of these costs). Rates designed based on these costs and BPA's projected FY 1983 sales volume, would recover revenues of approximately $5.7 billion. This would recover revenues approximately 250 percent over the no action alternative and 133 percent over the proposed revenue level.

e. Phased-In LRIC

BPA has not developed a precise methodology for phasing in LRIC based rates. To ease the impact of a sudden shift to marginal cost pricing, one possibility would be a phase-in over a 5-year period. Beginning with this 1982 proposal, BPA would calculate its repayment requirements and resultant rates as is done presently. Then based on the LRIC Analysis, BPA would add to the conventional rate one-fifth of the difference between the conventionally set rates and the LRIC based rates. This process would be continued with the amount of the differential added to the conventional rate increasing by one-fifth in each of the five successive years until rates would reflect full marginal cost. Applied to BPA's projected FY 1983 sales volume, rates designed in this manner would recover revenues of approximately $3.1 billion. This would recover revenues approximately 90 percent over the no action alternative and 27 percent over the proposed revenue level.

2. Revenue Comparison of Alternatives

Table V-1 compares the expected revenues under the alternatives with the proposed repayment requirement for FY 1983. Table V-2 summarizes the comparison of the revenue impacts of the alternatives. The no action alternative would result in an estimated revenue deficiency of $731 million, providing only 70 percent of the revenues necessary to meet BPA's repayment needs. Thus, BPA would be unable to meet its financial obligations for FY 1983. This revenue shortfall would need to be added to subsequent repayment periods to allow BPA to meet its long-term financial obligations. This would increase the financial burden on future ratepayers and present equity problems, depending on the particular distribution of the burden to future rate classes. The no action alternative, therefore, would violate BPA's statutory requirement to be self-financing, would not fully cover all financial obligations, and would necessitate recovery of a shortfall from future ratepayers.

The proposed alternative is expected to provide sufficient revenues to meet BPA's FY 1983 repayment requirement. This alternative would not present the problems of under or overcollecting revenues. Thus, it does not place an inequitable burden on future ratepayers to compensate for revenue shortfall nor does it require BPA to credit any excess revenues to ratepayers. This alternative allows BPA to meet all financial obligations and achieves rate equity, in that customers receiving service during FY 1983 would pay the full costs incurred during FY 1983 to provide that service.

TABLE V-1
FY 1983 REVENUE LEVEL ALTERNATIVES
($ MILLIONS) a/

		A	B	C	D	E
		Revenue Alternative				
Line No.	Revenue Consequences	No Action (Existing Rates)	Proposed b/	Modified Proposed Rates c/	Phased-In LRIC	LRIC
1.	Expected Revenues	1,709	2,440	2,324	3,087	5,676
2.	Revenue Required for Proposed Repayment	2,440	2,440	2,440	2,440	2,440
3.	Revenue Surplus/ (Shortage)	(821)	---	(116)	647	3,236
4.	Expected Revenues as Percent of Proposed Repayment	66	100	95	127	233

a/ Assumes estimated FY 1983 loads without any variation as a result of pricing alternatives; the only variables are the firm power rates for the particular alternative.

b/ Assumes proposed rates will meet BPA's total FY 1983 revenue requirement.

c/ Calculated by reducing the FY 1983 repayment requirement by the sum of irrigation assistance, incorporating the monetary impact of shifting to an 85 year generation plant accounting life, and assigning the Supply System Plants 4 and 5 shared costs to Plants 1 and 3 (these modifications are estimated to be 5 percent of FY 1983 revenue requirement before the costs of the exchange are added).

TABLE V-2
FY 1983 REVENUE LEVEL COMPARISON
1982 REVENUE ALTERNATIVES

Line No.	Criteria	A No Action (Existing Rates)	B Proposed	C Modified	D Phased-In LRIC	E LRIC
1.	Meet BPA statutory requirements	No	Yes	Possibly a/	No	No
2.	Meet all required financial obligations	No	Yes	No b/	Yes	Yes
3.	Maintains equity between present and future ratepayers c/	No	Yes	Possibly d/	No e/	No e/

a/ Would require legislative amendment.
b/ Does not meet present obligations. Would require removal of legislative obligation for irrigation assistance and assumes that some entity completes Supply System Plants 4 and 5.
c/ Assumes present ratepayers should pay all costs incurred during period of service.
d/ Subject to impediments to modifying the revenue requirement as described are removed.
e/ Assumes a strict interpretation of equity and does not consider the possibilities of prepayment of amortization, a lump sum payment to ratepayers, or a local government subsidy. These options raise equity questions and increase the administrative burden.

Modifications of BPA's repayment requirement as described previously are either outside BPA's current statutory authority and thus would require Congressional action in order to implement the modification, or would violate current contractual agreements. Discontinuing payment for irrigation assistance would be inconsistent with Congressional intent, as expressed in the Grand Coulee Third Power Plant Act of 1966, that BPA supplement the irrigators' repayment obligations. Exclusion of the shared facilities' costs would violate the terms of the net-billing agreements requiring that BPA cover 100 percent of the cost of Supply System Plant 1 and 70 percent of the cost of Plant 3. If the irrigation assistance and shared facilities costs were merely excluded from the 1982 revenue requirement, these costs would ultimately be borne by future ratepayers and would have corresponding equity implications. Generation plant life could be extended to 85 years and/or BPA could shift to a cost accounting, fixed amortization schedule approach for its transmission and generation plant. Both would require approval by the Department of Energy and the Office of Management and Budget, and potentially these changes could require Congressional action. The net impacts on revenue needs of this action would be minimal.

Both the revenue level based on LRIC pricing and that based on the phased-in LRIC would yield revenues significantly in excess of BPA's repayment requirement for FY 1983 and all years for the foreseeable future. However, the phased-in LRIC would result in fewer excess revenues in the short run than would the LRIC approach. However, both would violate BPA's Congressional directive in the Bonneville Project Act "to encourage the widest diversified use of electricity" at the "lowest possible rate . . . consistent with sound business principles." This overcollection would raise potential equity and significant administrative questions as to a mechanism for equitably distributing and/or investing excess revenues in the interest of the regional ratepayers. Either of these LRIC based revenue levels would, of course, more than enable BPA to meet all of its financial obligations.

3. Environmental Consequences of the Alternatives

The alternative revenue levels have varying consequences for the physical and the socioeconomic environments. These potential impacts are outlined in Table V-3. This table consists of a matrix assessing the no action, proposed, and LRIC alternatives. The modified repayment proposal is not included because the impact of this alternative would be very close to that of the proposed alternative both in the short and long run (see Table V-1).

As the matrix demonstrates, the no action alternative would be expected to have the most negative impact on the physical environment and the most beneficial impact on the region's socioeconomic environment. On the other hand, the LRIC alternative would be expected to have the most positive effect on the physical environment and, at least in the short-term, the most negative effect on the socioeconomic environment. The impacts of the other alternatives would fall within the range defined by the no action and LRIC alternatives.

a. Effects on Demand for Electricity

Based on BPA's econometric analysis (Energy Simulation Model), one can expect that an increase in the price for electricity will result in a decrease in the consumption of electricity. The effect of each revenue alternative on electricity consumption is presented in Table V-4. For each alternative, this table provides information on the total projected amount of regional electricity consumption. The years 1990 and 2000 were selected to demonstrate estimated short and long run price effects, respectively.

TABLE V-3
COMPARATIVE ANALYSIS OF
IMPACTS OF REVENUE LEVEL ALTERNATIVES:
1982 ANALYSIS

Item No.	Revenue Level ($ millions)	A Need for Generation	B Conservation	C Fuel Switching (Btu's X 10)	D Agriculture	E Water Quality/ Quantity	F Air Quality	G Priority Firm Power Rates
1.	No Action 1,709	1990 Load = 140,991 GWh; Plant Capacity = 24,203 MW; 2000 Load = 194,826 GWh; Plant Capacity = 33,494 MW.	Serves as base case for comparison to other alternatives.	Base case: Regional consumption by fuel type in 2000 Oil = .75 Gas = 384 Coal = .020	Base case: Number of acres under irrigation in 2000 = 4.034 million; irrigation pumping load in 2000 = 3,671 GWh.	Base Case: Water diversion losses for irrigation in 2000 = 8.472 million acre feet; Stream siltation and Chemical contamination from irrigation would be greatest.	Base case	Average rate = 11.4 mills/ kWh.
2.	Proposed 2,440	1990 Load = 133,733 GWh; Plant Capacity = 22,957 MW; 2000 load = 179,366 GWh; Plant Capacity = 30,790 MW.	Base case minus Proposed in 1990 = 4,540 GWh; Base Case minus Proposed in 2000 =12,250 GWh.	Percent increase in consumption over base case by fuel type: Oil = 5.3 Gas = 1.8 Coal = 5.0	Percent decrease in irrigated acreage relative to base case by 2000 = 0.6; Percent decrease in pumping load = 11.7.	Percent decrease in water diversion losses = 0.6. Some reduction in chemical contamination and stream siltation due to irrigation.	Amount (tons) by which base case impact would be reduced in 2000: Particulates=214.7; SO_2=9.8; NO_x=15.5; hydrocarbons=6.7; CO=11.3; CO_2=19.0.	Average rate = 19.7 mills/ kWh.
3.	Phased-in LRIC 3,087	1990 Load = 114,652 GWh; Plant Capacity = 19,681 MW; 2000 Load = 145,158 GWh; Plant Capacity = 24,918 MW.	Base case minus Phased-in LRIC in 1990 = 7,320 GWh; Base Case minus Phased in LRIC in 2000 = 29,390 GWh.	Percent increase in consumption over base case by fuel type: Oil = 20.0 Gas = 14.1 Coal = 10.0	Percent decrease in irrigated acreage in 2000 = 18.5; Percent decrease in pumping load = 35.1.	Percent decrease in water diversion losses = 15.4; Significant redution of stream siltation and chemical runoff from irrigation.	Particulates= 575.5; SO_2= 28.5; NO_x= 42.6; hydrocarbons=18.0; CO=29.6; CO_2= 76.0.	Average rate = 26.6 mills/ kWh.
4.	LRIC 3,087	1990 Load = 114,807 GWh; Plant Capacity = 19,708 MW; 2000 Load = 147,681 GWh; Plant Capacity = 25,351 MW.	Base case minus LRIC in 1990 = 7,650 GWh; Base Case minus LRIC in 2000 = 28,110 GWh.	Percent increase in consumption over base case by fuel type Oil = 20.0 Gas = 13.0 Coal = 10.0	Percent decrease in irrigated acreage in 2000 = 18.3; Percent decrease in pumping load = 35.1.	Percent decrease in water diversion losses = 18.3. Greatest diversion decrease in impacts associated with irrigation.	Particulates= 575.5; SO_2= 28.5; NO_x=42.6; hydrocarbons= 18.0; CO=29.6; CO_2=76.0.	Average rate = 54.0 mills/ kWh.

TABLE V-4
ESTIMATED REVENUE LEVEL IMPACT
ON REGIONAL ELECTRIC LOAD a/

Line No.	Revenue Level	A Year 1990 Load b/ (GWh)	B Year 2000 Load b/ (GWh)
1.	No Action	140,991	194,826
2.	Proposed	133,733	179,366
3.	LRIC	114,807	147,681
4.	Phased-In LRIC	114,652	145,158

a/ Pacific Northwest Region firm residential, commercial, and industrial load from BPA's Energy Simulation Model.

b/ A gigawatthour (GWh) equals 10^6 kWh.

The lowest load would occur under the LRIC and phased-in LRIC pricing alternatives. Regional load requirements in the year 2000 would be 47,145 GWh's less under the LRIC alternative, and 49,668/GWh's less under the phased-in LRIC alternative, than under the no action alternative. Loads are somewhat lower under the phased-in approach than under the approach which assumes initiation of full LRIC pricing in FY 1980 because the delay associated with phasing in LRIC causes the final full value of LRIC to be higher (due to inflation) by the time the full LRIC level is achieved. The proposed revenue level alternative would result in a load that is 15,460 GWh's lower than that under the no action alternative.

These differences in electricity consumption would be the result of a combination of consumer responses to price including conservation and conversion to an alternative energy source. Studies by BPA for its 1974 rate increase (BPA, 1973, p. A-42) as well as by National Economic Research Associates (Devine, et. al., 1977, p. 95) indicate that roughly one-third of the demand response to electricity prices would take the form of reduced energy use with the remainder reflecting fuel switching. An analysis based on results obtained from data developed through use of BPA's updated econometric model during analyses performed for the 1982 rate increase indicated approximately four-fifths of the difference in electricity consumption under the no action and proposed alternatives is due to conservation. The remainder is due to fuel switching. Under the LRIC and phased-in LRIC alternatives, about three-fifths of the difference is due to conservation and two-fifths to fuel switching.

As Table V-5 demonstrates, both the proposed and LRIC alternatives induce changes in the estimated consumption of natural gas and oil by regional utility customers. In the year 2000 under LRIC pricing of electricity, natural gas consumption would be expected to be approximately 13 percent greater than under the proposed alternative; oil consumption would be 20 percent higher. The percent decline in electricity consumption under the LRIC alternative is projected to be greater in the year 2000 than in 1990 (14 and 18 percent, respectively). This could be attributed to consumers responding to the initial "jolt" of higher prices with investments in conservation. The greatest percentage of decline in electricity consumption is found under the phased-in LRIC (14 percent in 1990; 19 percent in 2000). This could be attributed to the fact that consumers have a longer lead time before the full LRIC level is reached and therefore are able to make earlier conservation investments.

TABLE V-5
ESTIMATED REGIONAL CUSTOMER ELECTRICITY, GAS, AND OIL CONSUMPTION IN BTU EQUIVALENTS a/
(10^{12} BTU'S)

		A	B	C	D	E	F
Line	Revenue	Year 1990			Year 2000		
No.	Level Alernative	Electricity	Gas	Oil	Electricity	Gas	Oil
1.	No Action	481	333	86	665	384	75
2.	Proposed	457	342	86	612	391	79
3.	LRIC Pricing	392	386	96	504	434	90
4.	Phased-In LRIC	391	386	98	496	438	90

a/ Assumes price established in 1983 and then held constant in real terms throughout the forecast period. West Group total public and private per BPA's Energy Simulation Model.

b. Effects on Need for New Generation

Over time, increases in the price for electricity and the corresponding decrease in the growth of demand for electricity will limit the regional need for new generation resources. Estimates of the total demand for generation that would result by the years 1990 and 2000 from each of the revenue alternatives for 1982 are presented in Table V-6. As indicated in Table V-6, the proposed alternative would require about 1246 fewer megawatts of plant capacity in 1990 and approximately 2654 fewer in 2000 than would the no action alternative. Corresponding figures for the difference between demand under the LRIC and that under the no action alternative would be approximately 4495 and 8093 megawatts, respectively. There is little difference in electricity demand in 1990 between LRIC and phased-in LRIC; in 2000 there is more of a difference (1 trillion Btu's and 8 trillion Btu's, respectively). There appears to be more switching to gas and oil under phased-in LRIC than occurs under LRIC. This could be due to the longer lead time of phased-in LRIC, allowing for more planning time for fuel switching.

TABLE V-6
ESTIMATED EFFECT OF REVENUE ALTERNATIVES
ON THE NEED FOR GENERATION CAPACITY a/

Line No.	Revenue Alternative	A Year 1990 Required Capacity (MW)	B Year 2000 Required Capacity (MW)
1.	No Action	24,203	33,444
2.	Proposed	22,957	30,790
3.	LRIC	19,708	25,351
4.	Phased-In LRIC	19,681	24,918

a/ Nameplate capacity required to serve estimated load (see Table V-4), assuming a 70 percent plant factor, a 5 percent transmission loss factor, and a 100 percent load factor.

For purposes of analyzing the environmental consequences, the additional capacity required under the no action and proposed alternatives, over and above that required for the LRIC alternative, is assumed to be met by a combination of coal and nuclear plants. However, increases in the regional demand for additional electricity as a result of lower electricity rates might increase the use of renewable resources for generation. All else equal, the greater the reduction in the rate of load growth, the lesser the need for all resources including renewables. 3/

c. Effects on Consumers

(1) Effects on Retail Rates

Preference Customers

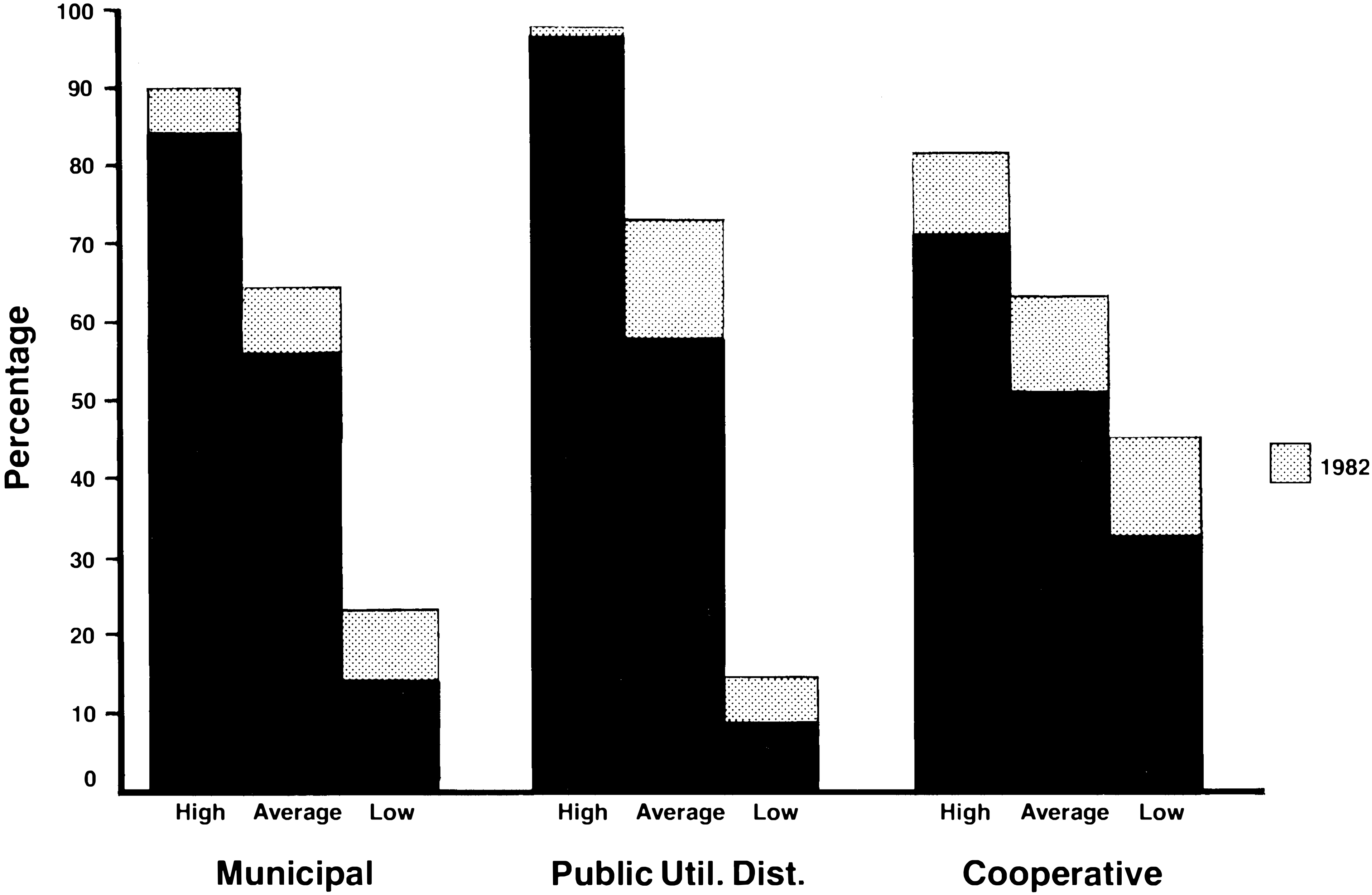
It is impossible for BPA to predict the exact impact of its revenue increase at the wholesale level on the retail rates of its utility customers. The individual effects depend on a number of factors including: (1) the amount of the utility's power obtained from BPA, (2) the utility's total operating costs, and (3) the utility's individual rate design. One utility may choose to simply increase its retail rates across the board regardless of customer class, while others may target the greater share of a rate increase toward a particular class of customer. Still other utilities may choose to increase and alter their current rate designs in an attempt to achieve greater efficiency.

Regardless of specific utility decisions, a BPA wholesale rate increase will result in an increase in the operating costs of the utilities purchasing from BPA. To illustrate this impact, the cost of BPA power as a percentage of the preference utilities' (municipalities, Public Utility Districts (PUD's), and cooperatives) total costs under the 1982 proposed revenue alternative is presented in Figure V-1. PUD's would experience the greatest range in the percent of total costs for purchase of BPA power under this increase (14 percent to 98 percent), followed by municipal utilities (22 percent to 90 percent), and cooperatives (45 percent to 81 percent). On the average, 64 percent, 72 percent and 63 percent of the total expenditures for municipal utilities, PUD's, and cooperatives, respectively, would be associated with the purchase of BPA power under the proposed revenue alternative.

The increase in utility purchase power costs as a percentage of total costs becomes magnified when these costs reflect the effects of the LRIC based revenue alternatives. Although not indicated in Figure V-1, the unconstrained LRIC alternative, if fully implemented in 1982, would increase power costs on an average of 358 percent for municipal utilities, 383 percent for PUD's, and 315 percent for cooperative utilities. Respective increases under the modified LRIC alternative, assuming FY 1983 as the initial year of implementation, would be 123 percent, 134 percent, and 113 percent.

FIGURE V-1

BPA POWER AS PERCENTAGE OF TOTAL UTILITY EXPENSES



Investor-Owned Utilities

In assessing the impact of a BPA revenue level increase on the retail rates of investor-owned utilities, two different factors must be considered: the effects on the residential and small farm exchange and the effects on the new resources pool. Under the provisions of the Regional Act, from July 1, 1982 to June 30, 1983, BPA is to serve 70 percent of the residential and small farm loads of exchanging utilities at the rate charged BPA's preference customers. Any cost benefits resulting from the exchange are to be passed through to the utilities' residential and small farm customers. The exchange provision of the Regional Act generally caused a decrease in the retail rates to the participating IOU's residential and small farm customers in 1981. BPA anticipates that the effects of implementing the proposed revenue level increase on the retail rates charged to the IOU's residential and small farm customers would be similar to the effects on BPA's preference customers as described above. If BPA were to implement the LRIC revenue alternative and BPA's consequent rate exceeds the average system cost of an exchanging utility the "Deemer provision" of the exchange contract would take effect. Under this provision the exchange would continue to be in effect, but BPA would compensate the utility for costs above the utility's average system cost. Thus the net effect would be a retail rate for residential and small farm consumers of an exchanging utility no higher than the rate that would have been determined based on the utility's costs. An account would be kept of the amounts of compensation provided to an exchanging utility whose average system cost fell below the priority firm rate. At such times as the utility's average system cost rose above the priority firm rate, BPA would pay only the priority firm rate for exchange resources provided by the utility until such time as return of the amounts provided to the utility through the deemer provision had been returned to BPA.

Under the provisions of the Regional Act relating to the new resources pool, BPA is to meet on request any IOU firm load deficits that existed prior to December 5, 1980, and any IOU load growth occurring after December 5, 1980, at the cost of BPA's newly acquired resources. The charges for providing this service would increase approximately 37 percent under the proposed alternative. This increase would not be expected to have a substantial impact on the retail rates of the IOU's because the service under this provision is so small relative to the other IOU costs. Whereas the total IOU load is forecast to be 7031 average megawatts in FY 1983, forecast IOU purchases under the new resources rate are only 492 average megawatts.

Pacific Southwest Utilities

The issue of impacts of BPA revenue level increases on the retail rates of Pacific Southwest Utilities, was addressed in the Final Environmental Impact Statement, 1979 Wholesale Rate Increase, V(A)(2) and VI(C)(4). The impact of the proposed or LRIC revenue levels on the retail rates in California again is expected to be limited to socioeconomic effects. For example, higher priced nonfirm energy sold to California utilities potentially could reduce the quantity of electricity demanded by all classes of customers in California and affect employment levels nominally in the manufacturing and small business sectors. California utilities that utilize nonfirm electricity from BPA generally reduce output from their most expensive generating units (usually oil-fired plants) leading to lower costs of energy to California consumers and a local reduction in atmospheric emissions. 4/ The proposed change in BPA's nonfirm rate is not expected to significantly alter the use of nonfirm energy by utilities in the Southwest. The average rate for nonfirm sales would be 9.5 mills per kilowatthour under the existing rate and 11.9 mills per kilowatthour under the proposed NF-2 rate (an increase of 25 percent).

(2) Effects on Low-income Consumers

Historical trends and consumer demand elasticities (ability to change demand in reponse to a change in price) are important indicators of the effects of increases in the price of electricity on the poor. As shown in Tables VII-5 and VII-6, the distribution of historic energy costs has had a disproportionate impact on low-income residential households. High-income consumers, by and large, have been able to slow the rate of growth in their home energy expenditures compared to the poor. Significant increases in BPA's electricity prices since 1979, have very likely had their most serious socioeconomic effects on low-income consumers (see Chapter VII(D)(4)).

In light of the historic evidence on the impacts of increasing energy prices and the consequences of differences in consumer demand elasticity, it would appear that the effects of the no action revenue alternative would be of greater immediate benefit to the poor as compared to other electric consumers. At the retail level, the increase in electricity prices under the no action alternative would essentially reflect the effects of inflation on those portions of utility costs not associated with purchasing power from BPA.

The proposed revenue alternative, in contrast, would increase the amount and proportion of income paid for electricity by low-income households. While more may be paid in absolute terms by high-income households, the increase in the proportion of total income paid would be less than for low-income consumers. Although the magnitude of the proposed alternative would be expected to cause low-income households to conserve electricity, the limited financial resources available to the poor inhibit their ability to effectively pursue many conservation measures. Furthermore, as previously stated, the uses to which the poor put electricity involve primary needs (cooking, lighting, refrigeration) rather than luxury uses (air conditioning, decorative lighting, etc.) and reductions in use may require serious changes in comfort and lifestyle.

The LRIC alternative (and also the phased-in LRIC) would have a much more severe impact on low-income households than either the no action or proposed alternatives. As demonstrated in the previous section, the LRIC alternative would increase the cost of power purchased by municipalities, PUD's and cooperatives, by an average of 358, 383, and 315 percent, respectively. Given cost increases of this magnitude, low-income persons in the region would experience disproportionate increases in the portions of their incomes required for the purchase of electricity relative to the portion spent by higher income persons. Unless adequate measures for mitigating the burden were developed, low-income consumers would be required to drastically alter their lifestyles in order to live within their income constraints. Moreover, while the impacts of the LRIC alternative would be most severe on the low-income, it also would exacerbate the problems for the near-poor and those on moderate incomes. These consumers' struggles to protect their budgets from the pressures of inflation and imposition of LRIC based rates would further erode their purchasing power.

The proposed alternative and especially the LRIC alternative (and phased-in LRIC) could pose especially serious problems for the low-income elderly, who number approximately 148,000 in the region. In the mid-1970's alone, the impact of energy price inflation increased the portion of the elderly poor's budget spent on fuel and utilities by an average of nearly 10 percent in the Pacific Northwest (Federal Energy Administration, 1975, p. 2.44). Compounding the problem for the low-income elderly is the fact that many are on fixed incomes that will not allow for significant flexibility to reduce their energy use or shift home budget-item expenditures.

Indirect socioeconomic consequences of the respective 1982 revenue level alternatives would depend on a number of underlying variables. Together with income level, these variables can exert pressure on the low-income consumer's ability to react to increases in electricity prices. Among them are: homeowner/renter status, location of residence, mix of energy sources utilized, retail rate structure and family size. For example, on the average apartment dwellers comprise a much larger percentage of the poor than of the nonpoor (33 percent to 8 percent), but in many cases lack the incentive to conserve because utility costs are included in rent and individually controlled thermostats are not always available (Grier, 1977, p. 17). In addition, opportunities for capital intensive conservation measures are simply not as available to the renter as they are to the homeowner.

d. Effects on Business and Industry

Assessing the effects of an electricity price increase on the operations of business and industry is very complex and, because of the diverse characteristics of industries, is necessarily speculative. Generally, electricity is a minor input to production in comparison to factors such as the costs of labor, materials, production process equipment, and transportation. Thus, an increase in electricity price generally is not a determining factor as to the economic viability of business and industry. Exceptions to this generalization may occur for industries where electricity is a major input in production or for those businesses that are at or near the margin and can not pass the increased costs on to their customers without becoming noncompetitive.

Researchers have found that industries for which electricity is a major factor in production include: primary metals (aluminum, other non-ferrous metals, and iron and steel), mining, chemicals, and pulp and paper. Not surprisingly, these industries also are found to be most responsive to changes in the price of electricity.

In the Pacific Northwest, some of the major industries in these categories comprise BPA's direct-service industrial customers (DSI). Under the provisions of the Regional Act, the DSI's are assumed to be served primarily by resources from the exchange pool and are to pay a rate sufficient to recover the cost of exchange resources used to serve them. This provision resulted in a substantial rate increase to the DSI's in 1981 (estimated at between 166 and 240 percent). BPA's 1982 proposed revenue level increase to the industrial customers is not as large (27.2 percent) as the percentage increase in 1981, or the 1982 proposed increase to the preference customers and to the IOU's (59.4 percent) for service to their residential and small farm customers. While the costs of the exchange resources are higher than the cost of resources assigned to priority firm customers, the relative increase is at a slower rate than the cost increases in the Federal base system resources.

Indications are that the previous and currently proposed BPA electricity price increases may have caused individual operations among the DSI's to approach parity with other production regions. Thus, in times of economic downturn, the most inefficient Pacific Northwest plants may experience slowdowns in operations or temporary shutdowns. In the cases of the least efficient plants, over time the individual companies may face decisions to improve the plant efficiency or possibly shut down operations entirely. The effect of BPA's 1982 revenue level increase to the DSI's may hasten the time for these decisions. This could be interpreted as a positive effect if the industries improve efficiency, increasing output for each increment of energy consumed. However, for those plants that cease operations entirely, there would be a negative economic effect on employment and regional income that could be severe for individual communities, depending on their dependence on the particular industry that discontinues operations.

BPA has not conducted a specific analysis to estimate the effects of LRIC or phased-in LRIC pricing on the DSI's. However, it can be logically concluded that an increase in electricity price of that magnitude (approximately 133 percent) for industries that are at parity with their competitors could not be passed on in increased product price (subject to market demand conditions) and therefore could cause substantial plant closures and resulting unemployment and reduced regional income.

e. Effects on Irrigated Agriculture

An increase in the price of electricity would be expected to affect Pacific Northwest irrigated agriculture. There could be: (1) changes in existing and future irrigated acreage; (2) effects on the average agricultural income; (3) changes in crop patterns; and (4) potential regional socioeconomic ramifications.

(1) Changes in Existing and Future Expected Irrigated Acreage

Table V-7 shows the 1990 and 2000 sprinkler irrigated acreage and power requirements effects on land which existed in 1982. A later table shows the effects on land which may be developed in the future for irrigation. Under the no action alternative, irrigated acreage is expected to decrease by less than 1 percent, from 4,057,381 to 4,034,262 acres, between 1990 and 2000. Over the same period, irrigation power requirements are projected to decrease by approximately 10 percent, from 4067 to 3671 GWh/year. These adjustments are the result of irrigators' long run responses to prior electricity rate increases by improving their management and technology, and reducing their acreage to minimize their costs.

TABLE V-7
ESTIMATED EXISTING SPRINKLER IRRIGATION RELATED POWER DEMAND, POWER USE, AND ACREAGE IMPACTS

		A	B	C	D
		Year 1990			
Line No.	Revenue Level Alternative	Irrigated Acreage	Power Requirements (GWh/Yr)	Avoided Diversion Losses a/ (GWh/Yr)	Net Requirement Reduction (GWh/Yr)
1.	No Action	4,057,381	4067	--	--
2.	Proposed	4,057,381	4035	32	64
3.	LRIC b/	3,676,481	3225	842	1684
		Year 2000			
4.	No Action	4,034,262 c/	3671 c/	--	--
5.	Proposed	4,011,143	3243	428	856
6.	LRIC	3,295,580	2383	1288	2576

a/ Diversion losses are foregone hydroelectric production as a result of irrigation water withdrawn from streamflows; assumes a 1:1 ratio between irrigation power use and avoided diversion losses.

b/ Assumes LRIC power cost equal to 57.2 mills/kWh; also assumes linear adjustment process from short to long run.

c/ Assumes a reduction of acreage and power requirements equivalent to 50 percent of the reduction expected to occur under the proposed alternative. This assumption accounts for irrigators response to BPA's past rate increases.

Under the proposed alternative, irrigated acreage in 1990 is expected to remain the same as under the no action alternative and power requirements are expected to decrease by an additional 32 GWh/year over that under the no action alternative. When avoided diversion losses resulting from water remaining in the stream that would have been withdrawn for irrigation are added, net power requirements are expected to decrease by an additional 32 GWh/year for a total of 64 GWh/year. By the year 2000, the proposed alternative would reduce irrigated acreage from that expected under the no action alternative by less than 1 percent to 4,011,143 acres. Irrigation power requirements would decline to 3243 GWh/year, for an approximate 12 percent reduction from that expected in the year 2000 under the no action alternative.

The LRIC alternative would produce the most significant reductions in acreage and power usage. By the year 2000, acreage could be 18 percent or 739,000 acres below that expected with the no action alternative. The resulting power requirements would be 35 percent lower under the LRIC alternative for a total of 2383 GWh/year in 2000. The net requirements reduction under the LRIC alternative, including avoided diversion losses, is projected to be 2576 GWh/year by the year 2000. Again, this difference in power requirements is a function of reduced acreage, the implementation of alternative irrigation management and technology, and avoided diversion losses. The phased-in LRIC alternative was not analyzed separately as to its effects on irrigated agriculture. It could be assumed that the effects would closely follow the effects of full LRIC.

The estimated long run impacts of electricity price on the development of new irrigated acreage in the Northwest are outlined in Table V-8. It should be noted that from the farmer's perspective, the final determination as to the economic feasibility of developing new irrigated lands is not solely a function of electricity price. Capital and land subsidies, tax incentives, crop support prices, available technology, other input costs, and existing and projected market demand, are other factors that influence the decision to develop a given tract of land.

As indicated in Table V-8, development of new irrigated acreage would not be expected to differ measurably under the no action and proposed alternatives. Implementing the LRIC alternative, however, could result in approximately 400,000 fewer acres being brought under irrigated agricultural production. 5/ As a result of not developing this land, power requirements would be reduced by about 1800 GWh/year, including reduced diversion losses.

(2) Agricultural Income Impacts

Table V-9 shows projected long run changes in net farm income as a result of changes in electricity price. The table displays estimated income effects of the proposed alternative and the LRIC alternative in 2000 by state and subregion. (Figure VII-1 shows the major subregions of the Pacific Northwest.) Regionwide, the proposed alternative could, in the long run, reduce farm incomes by an average of $3 per acre and the LRIC alternative could cause an average income reduction of $29 per acre in 2000.

When the effects on specific subregions are addressed, most of the long run changes in profitability are relatively small, with only the Mid-Columbia regions of Washington and Oregon showing changes of $10 or more per acre in response to the proposed revenue level by the year 2000.

TABLE V-8
ESTIMATED POWER DEMAND, POWER USE, AND ACREAGE
IMPACTS OF FUTURE IRRIGATION DEVELOPMENT IN YEAR 2000

		A	B	C	D	E
Line No.	Revenue Alternat.	Probability of Development	Irrigated Acreage	Power Require. (GWh/Yr)	Diversion Losses a/ (GWh/Yr)	Net Require. (GWh/Yr)
1.	No Action	Most Likely	472,000	1194	1505	2699
		Less Likely	257,000	447	223	670
		Total	729,000	1641	1728	3369
2.	Proposed b/	Most Likely	472,000	1194	1505	2699
		Less Likely	257,000	447	223	670
		Total	729,000	1641	1728	3369
3.	LRIC c/	Most Likely	316,240	800	1008	1808
		Less Likely	-	-	-	--
		Total	316,240	800	1008	1808

a/ Derived from Whittlesey, January 1982 study, Table 18, p. 50
b/ Whittlesey assumed that BPA's October 1982 rate proposal would not be the primary factor in the development of future acreage and that non-electricity price factors would have the major impact.
c/ It was assumed that the LRIC alternative would reduce the most likely category by one-third and eliminate the less likely category.

In the long run, the LRIC based price increase would result in significantly larger farm income changes than the no action or proposed alternatives. The income effects shown in Table V-9 reflect the average price for all sprinkler irrigated acreage in the Northwest. Consequently, those farms with high pump lifts in each region would experience greater income effects than farms with low pump lifts. Also, only those farms buying electricity to divert and apply water were considered.

TABLE V-9
ESTIMATED REAL DECREASE IN NET FARM INCOME IN
RESPONSE TO 1982 REVENUE LEVEL ALTERNATIVES, 2000 a/

		A	B
		Long Run Decrease in Income ($/Acre/year)	
Line No.	State/Region	Proposed Alternative	LRIC Alternative
	Washington		
1.	Northern Idaho	5	22
2.	Upper Columbia	8	40
3.	Yakima	4	21
4.	Lower Snake	5	23
5.	Mid Columbia	12	47
6.	Lower Columbia	3	14
7.	State Average	8	36
	Oregon		
8.	Mid Columbia	11	44
9.	Willamette	.50	13
10.	Klamath	4	28
11.	Mid Columbia (central)	.50	17
12.	Central Snake	1	21
13.	Closed Basin	3	18
14.	State Average	4	24
	Idaho		
15.	Central Snake	2	43
16.	Upper Snake	-7	13
17.	State Average	-3	27
18.	Montana	3	12
19.	Regional Average	3	25

a/ Farm income effects are estimated for only those acres currently under sprinkler irrigation. No adjustment is made for anticipated additions to acreage under irrigation. The short run (year 1990) effects of the proposed alternative are not expected to be appreciably different from the long run (year 2000) effects. If the no action alternative were maintained there would not be any expected decrease in farm income. Consequently, the no action alternative is not shown in this table. The price induced income reductions are given only for the year 2000; the intermediate year 1990 effects could be more severe because of the inability to make intermediate adjustments on the part of the region's "marginal" farms.

In sum, the relative income effects of the alternatives vary by subregion, with the LRIC alternative having a substantially greater effect than the proposed alternative. These estimated income effects allow for changes in crops and utilization of newer technology. The ultimate income effects will vary with changes in actual future market demand and farm cost conditions.

(3) Changes in Crop Patterns

No analysis was undertaken to determine the specific changes in crop type and/or crop patterns that may be induced by higher electricity prices. As mentioned earlier, farmers will respond with a mix of changes in order to maximize their overall returns or, in some instances, to minimize their losses. Beneficial techniques that may be implemented include better irrigation management, improved pumping efficiency, improved irrigation technology, altered crop patterns, and possible reversion to dryland farming. These adjustments to higher electricity prices (as well as changes to other input costs) have been and will continue to occur over time as farmers react to changing costs.

(4) Socioeconomic Ramifications

The ultimate socioeconomic impacts of increased electricity prices on irrigators and their respective communities at this time are very speculative. However, the proposed alternative would be expected to result in withdrawal of approximately 23,000 more acres of existing irrigated acreage from sprinkler irrigation by 2000 than under the no action alternative. This represents a reduction of about one-half of one percent of the total acreage expected to have been irrigated if the no action alternative were implemented. The LRIC alternative would result in 779,000 fewer acres in sprinkler irrigation, or about 19 percent less than that expected under the no action alternative. These reductions could result in some individual farmers going out of business and some acreage reverting to dryland agriculture. Other acreage, especially under the LRIC alternative, may be withdrawn from production altogether. The ultimate community and regional impacts will depend on the locations of the most seriously impacted farms. For example, communities with a large proportion of marginal farms may experience a disproportionate share of economic impacts.

In contrast to the potential negative impacts of an electricity price increase on irrigated farm lands are the potential positive impacts associated with a reduction in the amount of power required for irrigation and the associated avoided diversion losses. The reductions in existing irrigated acreage that would occur under the proposed and LRIC alternatives could result in projected power savings of 856 GWh/year and 2584 GWh/year, respectively, by the year 2000. Assuming 5 percent transmission losses and a 70 percent plant factor, by the year 2000 the proposed and LRIC alternatives could result in power reductions from irrigated agriculture that would avoid the nameplate generation equivalents of 147 MW and 444 MW of plant, respectively, relative to the no action alternative.

With regard to the projected effects on future irrigated acreage, the proposed alternative would not be expected to reduce the requisite power requirements below those anticipated under the no action alternative, while the LRIC alternative could reduce nameplate generation requirements by 268 MW by the year 2000. The data presented in Tables V-7 and V-8 is summarized in Table V-10 to present aggregate estimated present and future acreage and power effects under the three 1982 revenue level alternatives in the year 2000. As shown in the table, by the year 2000 the proposed and LRIC alternatives could result in power requirements for irrigation of 49 and 326 average megawatts less than requirements under the no action alternative. These reductions represent nameplate generation capacity amounts of 74 MW and 490 MW, respectively, assuming a 70 percent plant factor and a 5 percent transmission loss factor. These savings would result in a reduction in the need for future generation resources and thus would avoid the costs necessary to supply this generation.

TABLE V-10
ESTIMATED AGGREGATE SPRINKLER IRRIGATED ACREAGE AND POWER IMPACTS RESULTING FROM 1982 REVENUE LEVEL ALTERNATIVES

		A	B
		Year 2000	
Line No.	Revenue Level Alternative	Irrigated Acreage	Power Requirements a/ (aMW)
1.	No Action	4,763,262	804
2.	Proposed	4,740,143	755
3.	LRIC	3,611,820	478

a/ Includes direct irrigation electricity consumption plus additional or avoided diversion losses (aMW = GWh/8.76).

f. Effects on the Physical Environment

The primary physical environmental effects of an increase in BPA's revenue level are those that are avoided because of the difference in the amount of generation required to serve load and those that result from switching to other sources of energy. As noted earlier, the proposed and LRIC revenue level alternatives would result in the need for significantly less generation by the year 2000 (2654 MW and 8,093 MW, respectively) than would the no action alternative. For purposes of evaluating possible environmental effects that could be avoided by implementing either the proposed or LRIC alternatives, the avoided capacity is assumed to be a combination of coal-fired and nuclear facilities. Table V-11 indicates that by the year 2000, the increase in rates under the proposed alternative relative to the no action alternative would dampen demand for electricity sufficiently to avoid the need for and consequent effects to the physical environment of constructing and operating three

500 megawatt coal plants and one 1000 MW nuclear plant. The LRIC alternative, on the other hand, would avoid the equivalent effects of eight 500 MW coal plants and four 1000 MW nuclear plants. It is assumed that the phased-in LRIC would have similar results.

TABLE V-11
CHANGE IN GENERATION REQUIREMENTS AND EQUIVALENT FACILITIES IN RESPONSE TO 1982 REVENUE LEVEL ALTERNATIVES, YEAR 2000

Line No.	Revenue Alternative	A Avoided Generation (average MW)	B Equivalent Facility a/
1.	Proposal	2,654	3 coal 1 nuclear
2.	LRIC	8,093	8 coal 4 nuclear

a/ Assumes coal fired to nuclear facilities in a ratio of 2:1 (1 coal = 500 MW; 1 nuclear = 1000 MW). Facilities allocated based on the assumption that if remaining capacity were over 250 MW, a coal facility would be added with sale of excess capacity and if remainder were under 250 MW additional needs would be met through purchases. The discrepancy between the Energy Simulation Model and environmental analysis capacity factors is assumed to be negligible and provided for in rounding to the nearest coal facility.

Table V-12 summarizes the major annual environmental effects that would be avoided annually by these alternatives. These environmental effects would be associated with three distinct activities: mining, processing, and power production. These activities generally occur at different locations. Mining and processing are expected to occur primarily outside the region. All the activities have land use, solid waste, water, and air quality impacts.

TABLE V-12
ENVIRONMENTAL EFFECTS OF GENERATION AVOIDED
ANNUALLY BY THE YEAR 2000 AS A RESULT OF 1982 REVENUE
LEVEL ALTERNATIVES

Line No.		A Proposal	B LRIC
	Mine Site		
1.	Land Use, permanent (acres) a/	14.3	38.6
2.	Overburden Removed (tons)	1,402,235.0	5,605,960.0
3.	Process Water Used (acre/ft)	28.4	86.8
4.	Solid Waste (tons) b/	50,676.0	140,696.0
	Air Pollutants (tons)		
5.	Particulates	214.7	575.5
6.	SO2	9.8	28.5
7.	NOx	15.5	42.6
8.	Hydrocarbons	6.7	18.0
9.	CO	11.3	29.6
10.	CO2	19.0	76.0
	Water Pollutants (tons) b/		
11.	Dissolved Solids	11,170.7	44,455.2
12.	Suspended Solids	8.7	23.2
13.	Other	167.9	448.0
	Process Sites		
14.	Land Use, permanent (acres) a/	.2	.8
15.	Process Water Used (acre/ft)	1422.5	5,690.0
16.	Solid Waste (tons) b/	3.0	12.0
	Air Pollutants (tons)		
17.	Particulates b/	51.8	207.2
18.	SO2	199.4	797.6
19.	NOx	52.5	210.0
20.	Hydrocarbons	.5	2.2
21.	CO	1.3	5.2
22.	Water Pollutants (tons) b/	5.0	20.0
	Generating Site		
23.	Land use, permanent (acres) a/	119.4	323.6
24.	Process water used (acre/ft)	1,255.5	4,404.0
25.	Solid Waste (tons)	56,121.0	149,656.0
	Air Pollutants (tons)		
26.	Particulates	341.4	3,641.6
27.	SO2	2,537.7	4,036.0
28.	NOx	9,011.7	3,729.6
29.	Hydrocarbons	71.4	190.4
30.	CO	225.9	602.4
31.	Other b/	.1	.4
	Water Pollutants (tons)		
32.	Dissolved Solids	2,620.5	6,988.0
33.	Suspended Solids	1.0	2.6
34.	BOD	4.2	11.2
35.	COD	411.6	1,097.6
36.	Nitrates	5.6	15.2
37.	Other b/	23.9	95.6

a/ This represents total permanent disturbance and is not on an annualized basis.

b/ Denotes radioactive materials included.

The environmental effects that would be avoided as a result of the lower need for electric generation facilities under the proposed and LRIC alternatives would be somewhat offset by the physical environmental effects resulting from induced increases in the use of alternative energy sources. BPA's Energy Simulation Model assumes that the lower generation requirements under the proposed and LRIC alternatives will be compensated for by a combination of natural gas, oil, and conservation in a ratio of two increments of natural gas and oil to one increment of conservation. In fact the mix of alternative energy sources would be far more complex and would include a variety of renewable resources as well. The unknown nature of future substitution of alternative energy sources and the complexity of the actual mix makes quantification of the resulting environmental effects very speculative. Consequently, for purposes of this statement the potential effects of alternative resources will be briefly described with no quantification of the net environmental effects of the revenue alternatives.

Combustion of oil and natural gas cause atmospheric emissions of carbon monoxide, sulfur oxides, nitrogen oxides, carbon dioxide, hydrocarbons, particulate matter, water, and other materials. Additional impacts include increased solid waste disposal and increased impacts from extracting, refining, processing, and transporting these fuels. This increased direct fuel usage as a result of the proposed or LRIC alternatives would occur most significantly in populated areas where air quality problems are more common, such as Seattle, Everett, Tacoma, and Vancouver in Washington, and Portland and Eugene in Oregon. Of these cities, all but Everett currently violate one or more ambient air quality standards.

The environmental effects associated with the major renewable resources are summarized in Table V-13. Of these, direct combustion of wood for home heating appears to have substantial environmental consequences. The Oregon Department of Energy finds that "burning wood for home heating is the most rapidly growing source of air pollution in Oregon and the Pacific Northwest" (Hazen, 1980). For example, in Medford, Oregon, emissions from wood used for home heating are the source of two-thirds of the smaller, more harmful smoke particulates. 6/

Generally, the inputs to conservation involve: mining raw material; manufacturing construction materials such as metals, glass and insulation; fabricating the finished products; transporting to the point of use; and installing. These activities would result in some level of air and water pollutants and the risk of accident. Indoor air quality is a concern associated with weatherization of homes, and is the subject of a separate environmental impact statement currently being conducted by BPA. Many aspects of conservation activities are relatively labor intensive and would therefore have beneficial socioeconomic effects.

TABLE V-13
ENVIRONMENTAL EFFECTS OF MAJOR
RENEWABLE RESOURCE TECHNOLOGIES

Line No.	Technology	A Environmental Effects a/
1.	Passive Solar	indoor air quality, fire control
2.	Active Solar	structural safety, occupational hazard (installation) disposal of waste collector fluid
3.	Wind	structural safety in high winds
4.	Wood combustion	hydrocarbon, carbon monoxide, and particulate emissions, fire hazard
5.	Small-scale hydro	fisheries and other aquatic resource effects
6.	Geothermal	noise, brine, and effluent disposal
7.	Photovoltaics	occupational hazard (installation)
8.	Biomass conversion	land use, soil depletion, erosion, air pollution

a/ Sources: Bossong, K., "Hazards of Solar Energy," The Energy Consumer, January 1981, U.S. Department of Energy, Washington, D.C., pp. 26-27, Hayes, D. "Environmental Benefits of A Solar World," The Energy Consumer, January 1981, US Department of Energy, D.C., pp. 27-28, and U.S. Department of Energy, U.S. Department of State, 1981, New and Renewable Energy in the United States of America, DOE/S-0006 Washington, D.C., June.

In terms of air quality, it is unclear whether electricity or fossil-fuel for space heating has the greater total level of pollutants per unit of heat. However, the location of the pollution source and the ability to regulate the level of pollutants are important factors in assessing the relative impacts of each on the human environment. Electric generating plants, by the restrictions placed on their operation, design, and siting, would be required to meet air quality standards and "prevention of significant deterioration" regulations. In addition, they are generally located somewhat isolated from population centers. In this respect, air quality impacts of electric generating plants may be less than the impacts of direct application of fossil fuels or numerous small combustion plants. These activities are not as amenable to regulation and to technological means of limiting emissions and are generally located in populated areas with existing air quality problems (Charles River Assoc., 1978, pp. 175-179; Gordian Assoc., 1972 and 1974).

Adopting the proposed or LRIC alternatives also could have a number of other environmental effects. In terms of the agricultural sector, the proposed and LRIC alternatives would result in 23,000 and 1.1 million fewer acres, respectively, under sprinkler irrigation in the year 2000 than would the proposed alternative. Depending on whether these acres are evenly dispersed in the region or occur in a particular area, there could be appreciable environmental benefits. These environmental benefits could result from lower levels of water withdrawals, reduced siltation and lower amounts of pesticides used. These effects could be significant for particular aquatic environments.

Land which remains unirrigated or is removed from irrigation due to high electricity prices would in most cases remain in dry land agricultural production, would be used for grazing, or would remain undeveloped.

In terms of the effects of the revenue level alternatives on river operations, BPA does not foresee any changes in operation of the hydro system. On the average, 2.1 acre feet of water per acre of land are required annually to irrigate acreage in the Pacific Northwest. Therefore, by the year 2000, approximately 2.3 million acre feet of water would no longer be required for irrigation under the LRIC alternative that would be required under the no action alternative. Of this total, approximately 54 percent would return to the Columbia and its tributaries. Therefore, by the year 2000, river flows could be expected to be about 1.1 million acre feet greater under the LRIC alternative than under the no action alternative. This difference would amount to less than 1 percent of the average annual flow of the Columbia River as measured at The Dalles, Oregon. Furthermore, water withdrawals for irrigation occur primarily during the periods of greatest river flows. For these reasons, the potential effect of the various rate alternatives on the operation of the Federal Columbia River Power System and the use of the Columbia River and its tributaries would not be expected to differ significantly.

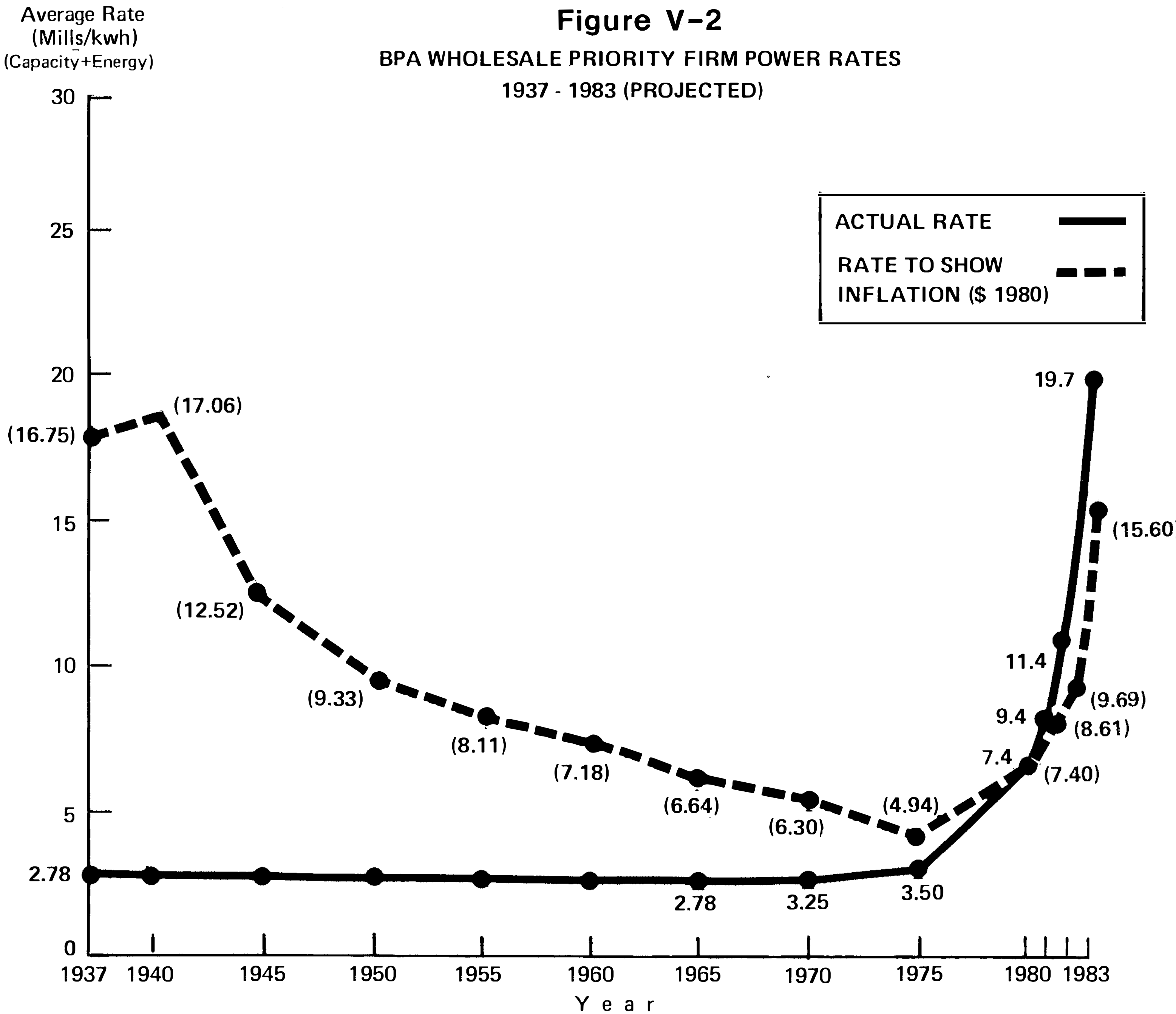
C. Alternative Cumulative Revenue Level Scenarios

BPA is responsible under NEPA to assess the cumulative impacts associated with its past, present, and anticipated future revenue level increases. This section will focus on the estimated short and long run consequences associated with revenue level increases occurring from December 20, 1979, through those expected to occur up to June 30, 1985. December 20, 1979, was selected as the point to begin the analysis because it marks the initial action in a series of substantial BPA revenue level increases that have occurred or will occur in a relatively short period of time. Figure V-2 shows the real cost (i.e., the cost of power adjusted to remove differences due to inflation) of priority firm power in 1981 dollars from 1937 to 1981 as well as the estimated real cost through 1985. As is evident from this figure, the real cost of power, measured against the Gross National Product Index, declined fairly steadily from 1937 to 1979 and then began a rather rapid increase. Consequently, the December 1979 through June 1985 period has been chosen as a period for which the impact of changes in electricity cost and consumption behavior in the Pacific Northwest should be assessed. It also should be noted that the real cost of power in 1985 is projected to be essentially the same as what it was in 1937 (17.75 versus 16.75 mills per kilowatthour, respectively).

Figure V–2

BPA WHOLESALE PRIORITY FIRM POWER RATES

1937 - 1983 (PROJECTED)



1. Description of Cumulative Revenue Level Alternatives

The expected cumulative short and long run consequences of BPA revenue levels for the 1979 to 1985 period are examined under four basic alternatives: (1) no action, (2) a proposed alternative which incorporates BPA's past revenue level increases and those projected to occur prior to July 1 1985, and (3) an LRIC based revenue level as if it had been implemented in 1979, the phased-in LRIC alternative.

a. No Action Alternative

The no action alternative assumes that BPA "froze" the rates that were in effect prior to December 20, 1979 (rates implemented December 20, 1974). These rates, approximately 3.5 mills per kilowatthour for priority firm customers, would then determine the resultant revenue levels in the period 1979 to 1985 and projected to 2000. Thus, with the rates remaining constant, revenue levels would increase only as load increased. The intent of this approach is to establish what would have happened had BPA taken no revenue increase actions during or subsequent to 1979. This establishes a base case from which the cumulative consequences of the past, proposed, and LRIC based revenue level increases can be evaluated and used to project 1990 and 2000 regional demand.

b. Proposed Alternative

The proposed alternative incorporates BPA's actual revenue level increases since 1979, the 1982 proposed revenue level increase, and anticipated revenue level increases through June 30, 1985. The rate as of June 30, 1985, is then held constant to project revenue levels to the year 2000. This alternative is designed to isolate the consequences of BPA's revenue level increases from 1979 to June 30, 1985, only. Thus, the short and long run consequences of these cumulative revenue level increases can be identified and load impacts can be projected for 1990 and 2000.

c. LRIC Alternative

This alternative assumes that BPA initiated unconstrained marginal cost pricing in 1979 and then held the resultant rate constant to the year 2000. The LRIC used in this analysis is based on BPA's 1982 LRIC analysis and resultant revenue level converted to 1979 nominal dollars. The 1982 LRIC analysis is used rather than the 1979 study because the more recent estimates of costs are considered to more accurately reflect BPA's projected future costs.

d. Phased-In LRIC Alternative

The phased-in LRIC alternative phases in the marginal cost pricing formula over a period of 5 years as discussed earlier.

2. Revenue Comparison of the Alternatives

Table V-14 summarizes the comparison of the revenue impacts of the alternatives. Under the no action alternative the revenue shortage would increase throughout the period of analysis to the year 2000. This assumes that the rate is held constant from December 20, 1979, onward. Thus, the no action alternative would significantly undercollect revenues that are necessary to cover BPA's financial obligations for all the subsequent years. This would have serious equity implications since at some future time ratepayers would be required to cover the costs of service provided to today's ratepayers because today's ratepayers would not be covering the cost of their service. The no action cumulative alternative, therefore, would repeatedly violate BPA's statutory requirement to collect revenues sufficient to meet present costs, would increasingly endanger BPA's financial solvency, and would require development of a mechanism to recover this increasing shortfall from future ratepayers.

The proposed alternative is expected to provide sufficient revenues to cover BPA's cumulative repayment requirements during the 1979-1985 period and would not present the problem of under or overcollecting revenues during the period. Thus, all financial obligations would be satisfied by consumers and they would bear the cost of providing their service. 7/ This alternative is consistent with BPA's statutory requirement to be self-financing while simultaneously setting rates as low as possible.

TABLE V-14
CUMULATIVE REVENUE LEVEL COMPARISON
1979-1985 REVENUE ALTERNATIVES

		A	B	C	D
Line No.	Criteria	No Action	Proposed	LRIC	Phased-In LRIC
1.	Meets BPA statutory requirement	No	Yes	No	No
2.	Meets required financial obligations	No	Yes	Yes	Yes
3.	Maintains equity between present & future ratepayers a/	No	Yes	No	No

a/ Assumes that equity requires that present ratepayers should pay all costs during period of service.

If BPA had established unconstrained LRIC based rates in 1979, it would have collected revenues substantially in excess of its costs in that and each subsequent year. This would violate BPA's congressional directive to promote widespread electricity usage at the lowest possible cost. It also would charge current ratepayers at a rate substantially higher than the actual cost of providing service to them. This situation would require BPA to develop a mechanism to redistribute these substantial excess revenues to the regional ratepayers in an equitable manner.

3. Environmental Consequences of Cumulative Alternatives

The four cumulative revenue level alternatives have varying consequences on the physical and the socioeconomic environments. These potential impacts are summarized in a matrix format in Table V-15. The evidence presented in the matrix supports the conclusion that the no action alternative would have the most negative impact on the physical environment and the most beneficial impact on the region's socioeconomic environment. At the other extreme, the LRIC option would be expected to have the most positive effect on the physical environment and the most negative effect on the socioeconomic environment. The effects of the proposed alternative would fall between these two extremes.

a. Effects on the Demand for Electricity

As was observed for the 1982 revenue level proposal and alternatives, an increase in the price of electricity, be it a single increase or a series of increases, will result in a decrease in the consumption of electricity. This effect is magnified by the size of the series of increases. The effect of each of the cumulative revenue level alternatives on electricity consumption as projected by BPA's Energy Simulation Model is presented in Table V-16. For each alternative, this table provides information on the total projected amount of electricity consumption by regional consumers under each of the cumulative revenue level alternatives during the years 1990 and 2000. The years 1990 and 2000 were selected to demonstrate estimated short and long run price effects, respectively.

Demand for electricity would be lowest under the cumulative phased-in LRIC pricing alternative. Regional generation requirements in the year 2000 would be 78,803 GWh's less under the phased-in LRIC alternative than under the no action alternative. Under the proposed revenue alternative demand would be 46,970 GWh's less than under the no action alternative. The disparity between the cumulative no action, proposed LRIC, and phased-in LRIC alternatives is greater than the difference between these approaches when applied to only the 1982 increase because the 1982 alternatives start with a common base in 1982 whereas the divergence among the cumulative alternatives begins in 1979.

By applying the 2:1 ratio of fuel switching to conservation described under the 1982 alternatives, estimates can be made as to the effects of the projected changes in loads under the cumulative alternatives. Approximately one-third of the difference in load between the no action, and proposed and LRIC alternatives would be the result of consumer conservation actions. These conservation actions are those over and above the conservation acquired under BPA's conservation programs, and thus are those induced by an increase in electricity price.

TABLE V-15
COMPARATIVE ANALYSIS OF
IMPACTS OF REVENUE LEVEL ALTERNATIVES:
CUMULATIVE ANALYSIS

Item No.	Revenue Scenario	A Need for Generation	B Conservation	C Fuel Switching (Btu's X 10)	D Agriculture	E Water Quality/ Quantity	F Air Quality	G Priority Firm Power Rates
1.	No Action	1990 Load = 153,147 GWh; Plant Capacity = 26,290 MW; 2000 Load = 220,164 GWh; Plant Capacity = 37,794 MW.	Serves as base case for comparison to other alternatives.	Base case: Regional consumption by fuel type in 2000 Oil = 67 Gas = 365 Coal = .015	Base case: Number of acres under irrigation in 2000 = 4.057 million. Irrigation pumping load in 2000 = 4,944 GWh.	Base Case: Water diversion losses for irrigation in 2000 = 8.521 million acre feet. Stream siltation and chemical contamination from irrigation would be greatest.	Base case	Average rate = 11.4 mills/ kWh.
2.	Proposed	1990 Load = 127,047 GWh; Plant Capacity = 21,809 MW; 2000 Load = 173,194 GWh; Plant Capacity = 29,731 MW.	Base case minus Proposed in 1990 = 15,250 GWh; Base Case minus Proposed in 2000 = 34,425 GWh.	Percent increase in consumption over base case by fuel type: Oil = 21 Gas = 8 Coal = 46.7	Percent decrease in irrigated acreage relative to base case by 2000 = 2.8. Percent decrease in pumping load = 38.6.	Percent decrease in water diversion losses = 2.8. Some reduction in chemical contamination and stream siltation due to irrigation.	Amount (tons) by which Base case impact would be reduced in 2000: Particulates=575.5; SO2=28.5; NOx= 42.6; hydrocarbons=18.0; CO=29.6; CO2= 76.0	Average rate = 19.7 mills/ kWh.
3.	Phased-In LRIC	1990 Load = 114,190 GWh; Plant Capacity = 19,602 MW; 2000 Load = 141,361 GWh; Plant Capacity = 24,266 MW.	Base case minus Phased-In LRIC in 1990 = 13,473 GWh; Base Case minus Phased-In LRIC in 2000 = 45,700 GWh.	Percent increase in consumption over base case by fuel type: Oil = 39 Gas = 24 Coal = 53.3	Percent decrease in irrigated acreage in 2000 = 18.8. Percent decrease in pumping load = 42.9.	Percent decrease in water diversion losses = 18.8. Significant reduction of stream siltation and chemical runoff from irrigation.	Particulates= 934.0; SO2= 45.4; NOx= 68.7; hydrocarbons=29.2; CO=49.3; CO2= 114.0.	Average rate increases from 26.6 mills/kWh in 1982 to 71.6 mills/kWh in 1987 and then remains constant through 2000.
4.	LRIC	1990 Load = 113,055 GWh; Plant Capacity = 19,407 MW; 2000 Load = 146,398 GWh; Plant Capacity = 25,131 MW.	Base case minus LRIC in 1990 = 12,875 GWh; Base Case minus LRIC in 2000 = 45,665 GWh.	Percent increase in consumption over base case by fuel type Oil = 34 Gas = 20 Coal = 53.3	Percent decrease in irrigated acreage in 2000 = 18.8. Percent decrease in pumping load = 51.8.	Percent decrease in water diversion losses = 18.8. Greatest decrease in diversion impacts associated with irrigation.	Particulates= 934.0; SO2= 45.4; NOx= 68.7; hydrocarbons=29.2; CO=49.3; CO2= 114.0.	Average rate = 54.0 mills/ kWh.

TABLE V-16
ESTIMATED CUMULATIVE REVENUE LEVEL IMPACT ON
REGIONAL ELECTRIC LOAD a/
(GWh) b/

Line No.	Revenue Alternative	A Year 1990 Load	B Year 2000 Load
1.	No action	153,147	220,164
2.	Proposed	127,047	173,194
3.	LRIC	113,055	146,398
4.	Phased-In LRIC	114,190	141,361

a/ Pacific Northwest Region firm residential, commercial, and industrial load estimated by BPA Energy Simulation Model.

b/ A gigawatthour (GWh) equals 10^6 kWh.

The remaining two-thirds of the difference between electricity loads under the no action, and under the proposed and LRIC alternatives is the result of substitution of other fuel sources for electricity. For each alternative, Table V-17 projects the amount (in Btu equivalents) of electricity, natural gas, and oil that would be used in 1990 and 2000 by consumers served by BPA's preference customers.

TABLE V-17
CUMULATIVE ANALYSIS OF ESTIMATED REGIONAL
CUSTOMER ELECTRICITY, GAS, AND OIL CONSUMPTION
IN BTU EQUIVALENTS a/
(10^{12} BTU'S)

		A	B	C	D	E	F
Line	Revenue	Year 1990			Year 2000		
No.	Level Alternative	Electricity	Gas	Oil	Electricity	Gas	Oil
1.	No Action	523	321	80	752	365	67
2.	Proposed	434	346	92	591	394	81
3.	LRIC	386	396	98	500	438	90
4.	Phased-In LRIC	390	392	96	483	452	93

a/ Estimated by BPA's Energy Simulation Model.

As shown in Table V-17, consumption of natural gas under the cumulative LRIC alternative is higher than under the proposed or no action alternative. In the year 2000 under LRIC pricing for electricity, natural gas consumption would be approximately 21 percent above that under the no action revenue alternative; oil consumption could increase by 34 percent above the levels projected for the no action alternative. The proposed alternative could increase natural gas consumption over the no action alternative by 9 percent by the year 2000. Again, the magnitude of the difference in effects of the alternatives is much broader than that under the action for a single year, reflecting the cumulative effects of the series of increases.

There is a small difference in electricity demand in 1990 between LRIC and phased-in LRIC, with more of a difference appearing in 2000 (4 trillion Btu's and 17 trillion Btu's, respectively). This could be due to the longer lead time of phased-in LRIC, allowing for earlier conservation investments.

b. Effects on Need for New Generation

The slowed growth in the demand for electricity as a result of increasing price will reduce the projected need for new generation resources. Table V-18 shows the estimated demand and generation impacts associated with the four cumulative revenue level alternatives. The estimated new generation capacity avoided as a result of the proposed and LRIC alternatives is 8,063 MW and 12,663 MW, respectively. For the purpose of analyzing the environmental consequences, the additional capacity required under the no action and proposed alternatives, over and above that required for the LRIC alternative, is assumed to be met by a combination of coal and nuclear plants.

TABLE V-18
ESTIMATED EFFECT OF CUMULATIVE REVENUE
ALTERNATIVES ON THE NEED FOR GENERATION CAPACITY a/

Line No.	Revenue Alternative	A Year 1990 Required Capacity (MW)	B Year 2000 Required Capacity (MW)
1.	No Action	26,290	37,794
2.	Proposed	21,809	29,731
3.	LRIC	19,407	25,131
4.	Phased-In LRIC	19,602	24,266

a/ Nameplate capacity required to serve estimated load (see Table V-16) assuming a 70 percent plant factor, a 5 percent transmission loss factor, and a 100 percent load factor.

c. Effects on Consumers

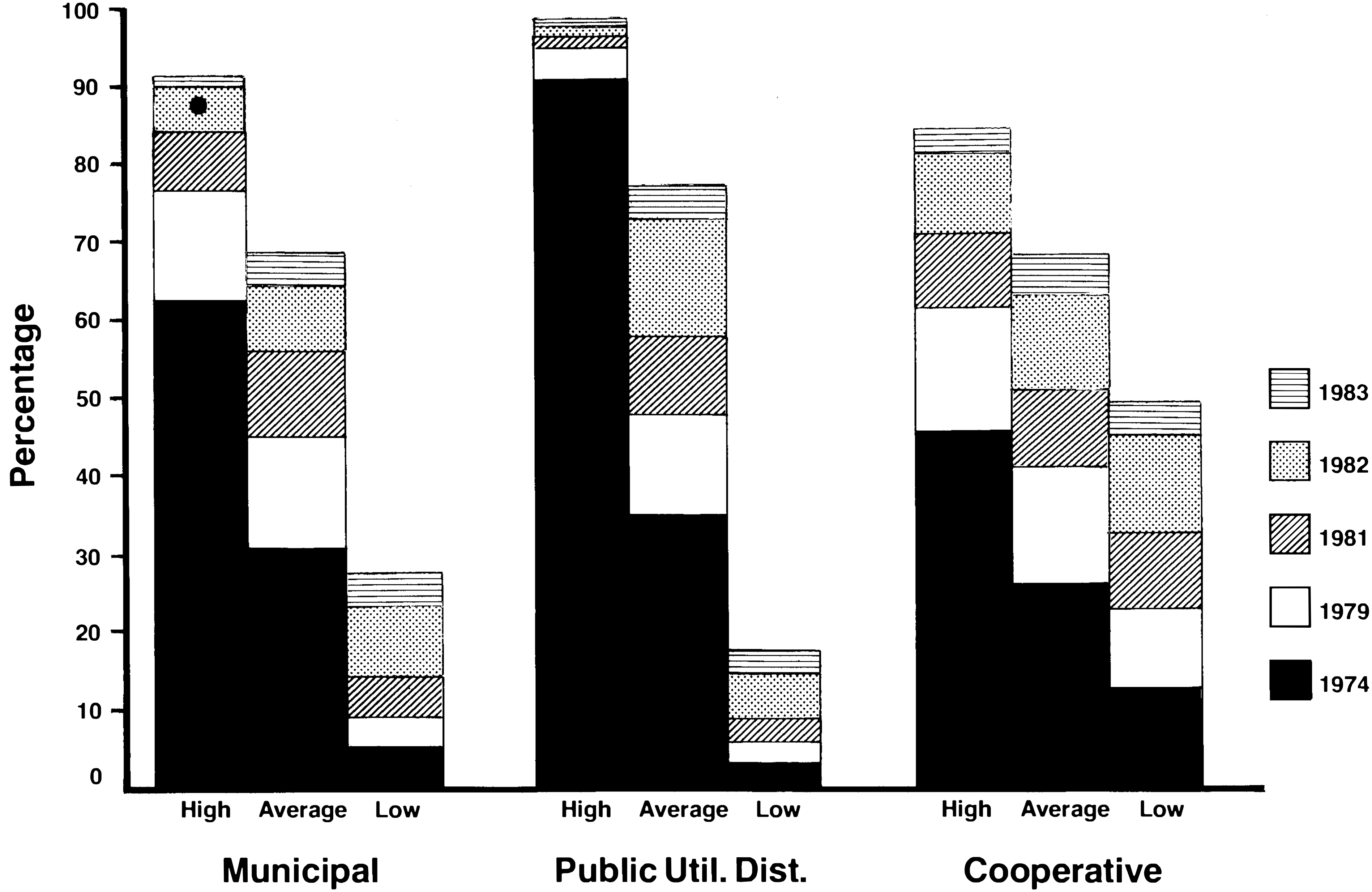
(1) Effects on Retail Rates

Preference Utilities

As in the case of the analysis of the 1982 revenue increase, cumulative BPA increases would cause increases in the retail rates of BPA's customers. Figure V-3 shows that municipalities, PUD's and cooperatives devoted, on the average, 56 percent, 58 percent, and 51 percent, respectively, of their total costs to the purchase of BPA power in 1981. Also indicated are the comparable percentages that would have resulted had the 1974 and 1979 rates been in effect in 1981. As noted earlier, had the proposed 1982 rates been in effect in 1981, purchases from BPA would, on the average, have represented 64 percent, 72 percent, and 63 percent of the total costs for municipalities, PUD's, and cooperatives, respectively. By FY 1984 under the proposed alternative, PUD's would apply the highest average percentage of their revenues toward the purchase of BPA power (76 percent), followed by municipal utilities and cooperatives (average of 68 percent for each class).

FIGURE V-3

BPA POWER AS PERCENTAGE OF TOTAL UTILITY EXPENSES



Investor-owned Utilities

Since BPA did not serve firm loads of the IOU's prior to July 1, 1981, no detailed analysis of the cumulative effect of BPA revenue level increases on IOU's has been conducted. For those utilities participating in the residential exchange program during FY 1983, 70 percent of their residential and small farm load could be purchased under the proposed PF-2 priority firm rate. The proportion would increase to 80 percent between July 1, 1983 and June 30, 1984 during which time BPA's projected October 1983 rate increase would take effect. The October 1983 rate increase would be maintained through June 30, 1985. During the period July 1, 1984 through June 30, 1985, 90 percent of the IOU residential and small farm loads would be eligible for service under the priority firm rate implemented in October 1983.

In addition to priority firm purchases, investor-owned utilities are expected to purchase very limited amounts of new resources firm power under the NR rate.

The increase in the October 1983 priority firm rate over the proposed October 1982 priority firm rate is projected to be about 22 percent. No estimate is yet available for the October 1983 new resources rate. The fact that the proportion of IOU load eligible for priority firm service increases from 70 percent to 90 percent between October 1, 1981 and June 30, 1985 would partially offset the upward effect of the priority firm rate increase on IOU costs.

Pacific Southwest Utilities

The impacts of the proposed, LRIC, and phased-in LRIC alternatives on the retail rates of California utilities will largely depend on the availability of nonfirm electricity and the demand for it in the Northwest during the study period. However, the proposed cumulative increase in BPA nonfirm power may still be less than the costs associated with the most expensive power resources in California.

The highest cost resources in the Southwest, typically oil-fired, have been considerably greater than BPA's secondary energy rate. Between 1965 and 1974, BPA's rate for secondary energy was 2 mills per kilowatthour. In 1974 the secondary energy rate was increased to 3.0 mills per kilowatthour during the summer and 3.5 mills per kilowatthour during the winter. In 1979, secondary nonfirm energy purchased for the purpose of displacing thermal generation was priced at one-half the decremental cost of the purchaser's highest cost resource with the condition that the rate not exceed 20 mills per kilowatthour or be less than 4.5 mills per kilowatthour for offpeak hours. The minimum charge for peak hours was 6.5 mills per kilowatthour. The average charge for nonfirm is 9.5 mills per kilowatthour at the present time. The proposed 1982 BPA nonfirm energy rate is 11.9 mills per kilowatthour. The growth in BPA's nonfirm energy rate between 1979 and projected 1983 represents a 65 percent increase.

When the Northwest/Southwest Intertie first became operational (mid-1970), oil-fired generation in California had incremental operating costs of 3 to 4 mills per kilowatthour. In 1979, average operating costs increased to 39 mills per kilowatthour for conventional oil-fired steam turbines and 58 mills per kilowatthour for oil-fired peaking units. 8/ BPA estimates average 1983 incremental operating costs of oil-fired generation at 70 mills per kilowatthour (conventional steam turbines) and 92 mills per kilowatthour (peaking units). Between 1979 and 1983, incremental operating costs increased, on the average, 79.5 percent for conventional oil-fired generation and 58.6 percent for oil-fired peaking generation.

The cumulative increased cost for nonfirm energy would increase the overall cost of power to retail consumers of most Northwest utilities purchasing nonfirm energy from BPA, thereby resulting in less consumption by those consumers. However, in the case of California utilities, BPA's nonfirm energy would be substantially less expensive cumulatively than higher cost resources as noted above. Nonfirm energy purchased by California utilities during the cumulative period could therefore displace the more costly resources and reduce energy costs to California consumers. Any reduction in the retail rates of California consumers resulting from the displacement of high cost resources could encourage the consumption of electricity and potentially create demand for additional generation facilities. On the positive side, displaced oil-fired generation would lead to a reduction in atmospheric pollutants.

As suggested at the outset of this discussion, explicit impacts of proposed cumulative energy costs on the retail rates of Pacific Southwest utilities depend in large measure on: (1) water conditions in the Northwest which vary from year to year, and (2) the proportion of nonfirm energy used by Northwest customers and the proportion of nonfirm energy which is then available to be passed through to California utilities from BPA or other utilities.

(2) Effects on Low-income Consumers

The cumulative impacts across consumer income groups of the no action, proposed, LRIC, and phased-in LRIC revenue level alternatives would be similar to, only stronger, than those associated with the single 1982 increase. All things being equal, low-income households would experience a larger proportionate increase in electricity costs over time (see Tables VII-5 and VII-6).

Under the cumulative no action alternative (maintaining the revenue level under rates in effect before December 20, 1979), electricity would be a relatively cheap commodity assuming that a utility's other costs increased at about the overall inflation rate. This in turn might stimulate the use of electricity as well as encourage purchases of electricity consuming devices. The extent to which this would occur would likely be inversely related to income level (i.e., the lower the income, the less the proportional increase in electricity consumed).

In contrast, the proposed cumulative alternative could lead to a wholesale rate increase of approximately 224 percent by 1985 over that in 1979. Consumers with average or above average incomes would have the option of mitigating the effects of such an increase through investment in conservation measures or alternative energy sources. The low-income consumer on the other hand, having less flexibility over his use of electricity, would face greater difficulty in adapting to rate increases and those higher costs passed along by business and industry.

The cumulative socioeconomic impacts of the LRIC and phased-in LRIC alternatives on low and fixed-income households would be the most severe of all the alternatives. Wholesale rates under this alternative could increase by 673 percent between 1979 and 1985. This could have serious effects on the social and economic well-being of the poor unless mitigated by income support and conservation assistance programs, and possibly through retail rate design.

As suggested earlier (see Chapter V(3)(C)(2)), empirical evidence and economic theory suggests that poor consumers have lower long run demand elasticities than the nonpoor since a larger share of their income is committed to necessities such as food, shelter, and clothing as well as energy (Barth, 1975, p. 85). For example, in 1979 those with incomes of less than $5,000 (1979 dollars) spent 23 percent and 26 percent of that income on food and shelter, respectively. Only 12 percent and 10 percent, respectively, of total gross income was devoted to food and shelter by those earning $25,000 and more (Bureau of Labor Statistics, 1978, p. 387). This is despite the fact that those same low-income consumers averaged expenditures of only $3,838 per year for food and shelter compared with $11,560 averaged by those with high incomes (1979 dollars). The poor, having already limited their consumption to essential needs, would have to experience genuine deprivation under LRIC (to a lesser extent under the proposed alternative) in the early to mid-1980's to achieve reductions in energy use in the absence of income transfer or energy conservation support.

The potential cumulative consequences of the proposed, LRIC, and phased-in LRIC revenue level alternatives would be particularly acute for the fixed income elderly poor. This segment of the population tends generally to be in worse health than the young. This often places strains on their mental and economic well-being. Moreover, the elderly poor are more susceptible to health problems aggravated by the cold (e.g., respiratory ailments, arthritis, accidental hypothermia), increasing the potential hazards of adapting to lower home temperatures (Design Alternatives, 1979, p. 6).

(3) Effects on Irrigated Agriculture

The analysis of the effects of the cumulative revenue level alternatives on existing sprinkler irrigated agriculture will be limited to projections of power use and acreage. Effects of the alternatives on future additions to irrigated acreage were not quantified because it is not anticipated that the additions would differ substantially from those presented under the single 1982 revenue level alternatives (Table V-8). Many factors in addition to electricity price will ultimately determine future additions to sprinkler irrigated acreage in the Pacific Northwest. The difference in power costs between the 1982 and cumulative alternatives are expected to play a relatively minor role in agricultural investment decisions.

Table V-19 shows the estimated acreage and power requirements for existing sprinkler irrigation under the three cumulative revenue level alternatives in the years 1990 and 2000. Irrigated acreage would be lowest under the LRIC alternative and highest under the no action alternative. About 762,000 more acres (representing a direct power requirement of about 2600 GWh per year) would be under irrigation by the year 2000 under the no action alternative than under the LRIC alternative. In the long run under the proposed alternative, 112,000 fewer acres of currently irrigated land would remain under irrigation than under the no action alternative and direct power requirements would be approximately 1900 GWh/year lower under the proposed than under the no action alternative. This represents a relatively small acreage adjustment. The difference in power requirements are a function of the amount of land in production, the efficiency of farm management and technology, and water diversion. A phased-in LRIC analysis was not developed for irrigated agriculture, however, it is assumed that such results would be similiar to the LRIC effects.

TABLE V-19
ESTIMATED EXISTING SPRINKLER IRRIGATION RELATED POWER DEMAND, POWER USE, AND ACREAGE IMPACTS

Line No.	Cumulative Revenue Alternative	A Irrigated Acreage	B Power Require. (GWh)	C Avoided Divers. Losses a/ (GWh)	D Net Require. Reduc. (GWh)	E Gener. Equiv. b/ (MW)
		Year 1990				
1.	No Action c/	4,057,381	4,944	--	--	--
2.	Proposed	4,057,381	4,005	939	1,878	322
3.	LRIC d/	3,676,481	3,225	1,719	3,438	590
		Year 2000				
No Action c/		4,057,381	4,944	--	--	--
Proposed		3,945,347	3,038	1,906	3,812	654
LRIC d/		3,295,580	2,383	2,561	5,122	879

a/ Assumes a 1:1 ratio between power use and avoided diversion losses.
b/ Nameplate capacity avoided to serve estimated net requirement reduction assuming a 70% plant factor, a 5% loss factor, and a 100% load factor.
c/ Assumes power consumption would remain at the 1979 level.
d/ Assumes LRIC energy and capacity cost equal to 57.2 mills/kWh and a linear adjustment process from the short to long run.

(1) Agricultural Income Impacts

Table V-20 shows long run changes in net farm income resulting from the cumulative effects of the proposed and LRIC revenue level alternatives. The table divides the estimated income impacts by state and subregion (see Figure VII-1). In the long run (2000) under the proposed alternative, the State of Washington would experience the greatest average per acre income reduction of $14 and Idaho would experience the lowest average per acre income reduction of $2. The average income reduction for the four states would be $7.50/acre/year. Under the LRIC alternative, the long run (2000) per acre income reductions are substantially greater than the under the proposed alternative. The average income reduction for the four states would be $32/acre/year under the LRIC alternative, which is almost four times the reduction under the proposed alternative. Again, Washington would experience the greatest average reduction ($42 per acre). The income reductions shown in Table V-20 reflect the average of all sprinkler irrigated acreage in the respective states and subregions. Those electricity intensive farms with high pump lifts would experience greater income effects than would farms with low pump lifts.

In sum, the relative income impacts of the alternatives vary by subregion, with the LRIC alternative having a substantially greater impact than the proposed alternative. This analysis of estimated income impacts allows for changes in crops and technological improvements. The ultimate income effects will vary with actual changes in future market and production cost conditions.

TABLE V-20
ESTIMATED DECREASE IN NET FARM INCOME IN RESPONSE TO CUMULATIVE REVENUE LEVEL ALTERNATIVES, 2000 a/

Line No.	State/Region	A: Decrease in Income From 1979 Levels ($/Acre/Year) — Proposed Alternative	B: Decrease in Income From 1979 Levels ($/Acre/Year) — LRIC Alternative
	Washington		
1.	Northern Idaho	10	27
2.	Upper Columbia	15	47
3.	Yakima	6	23
4.	Lower Snake	8	26
5.	Mid Columbia	23	58
6.	Lower Columbia	7	18
7.	State Average	14	42
	Oregon		
8.	Mid Columbia	21	54
9.	Willamette	1.50	13
10.	Klamath	7	31
11.	Mid Columbia (central)	3.50	19
12.	Central Snake	5	25
13.	Closed Basin	7	22
14.	State Average	9	39
	Idaho		
15.	Central Snake	8	49
16.	Upper Snake	-3	17
17.	State Average	2	32
18.	Montana	5	14
19.	Regional Average	7.50	32

a/ Farm income effects are estimated for only those acres currently under sprinkler irrigation. No adjustment is made for anticipated additions to acreage under irrigation. If the 1979 rates (no action alternative) were maintained there would not be any expected decrease in farm income. Consequently, the no action alternative is not shown in this table. The income reductions which would result under the LRIC and proposed alternatives are given only for the year 2000; the intermediate (1990) impacts could be more severe because of the possible inability by farmers to make intermediate adjustments.

e. Effects on the Physical Environment

The cumulative revenue level alternatives would have physical environment effects that are the same in type as those for revenue level alternatives for 1982 but the magnitude of the effects would be greater. The major category of effects would be those associated with the difference in the need for generation and the conversion to alternative energy sources as a result of the revenue level alternatives. Again, the proposed, phased-in LRIC, and LRIC alternatives would result in the need for significantly less generation capacity than would the no action alternative (8063 MW and 12,666 MW less, respectively). For purpose of analyzing the environmental consequences, it is assumed that the proposed alternative could avoid capacity equal to eight 500 MW coal-fired and four 1,000 MW nuclear facility in the year 2000 as shown in Table V-21. The LRIC alternative could avoid the capacity equal to thirteen 500 MW coal fired and six 1,000 MW nuclear facilities.

The annual environmental effects of avoiding the need for these facilities are shown in Table V-22. As was described for the 1982 revenue level alternatives the effect associated with mining and processing would likely occur outside the region and those from generation would occur within the region. All three activities would have land use, solid waste, water, and air quality impacts. (The values shown in Table V-22 realistically would be a range of effects. Refer to Chapter VII for specific environmental data.)

TABLE V-21
CHANGE IN GENERATION REQUIREMENTS AND
EQUIVALENT FACILITIES IN RESPONSE TO CUMULATIVE
REVENUE LEVEL ALTERNATIVES, YEAR 2000

Line No.	Revenue Alternative	A Avoided Generation (average MW)	B Equivalent Facility a/
1.	Proposal	8,063	8 coal 4 nuclear
2.	LRIC	12,663	13 coal 6 nuclear

a/ Assumes coal fired to nuclear facilities in a ratio of 2:1 (1 coal = 500 MW; 1 nuclear = 1000 MW). Facilities allocated based on the assumption that if remaining capacity were over 250 MW a coal facility would be added with sale of excess capacity and if remainder were under 250 MW additional needs would be met through purchases. The discrepancy between the Energy Simulation Model and environmental analysis capacity factors is assumed to be negligible and provided for in rounding to the nearest coal facility.

TABLE V-22
ENVIRONMENTAL EFFECTS OF GENERATION AVOIDED
ANNUALLY BY THE YEAR 2000 AS A RESULT
OF CUMULATIVE REVENUE LEVEL ALTERNATIVES

Line No.		A Proposal	B LRIC
	Mine Site		
1.	Land Use, permanent (acres) a/	38.6	62.5
2.	Overburden Removed (tons)	5,605,960.0	8,409,685.0
3.	Process Water Used (acre/ft)	86.8	136.9
4.	Solid Waste (tons) b/	140,696.0	226,546.0
	Air Pollutants (tons)		
5.	Particulates	575.5	934.0
6.	SO2	28.5	45.4
7.	NOx	42.6	68.7
8.	Hydrocarbons	18.0	29.2
9.	CO	29.6	49.3
10.	CO2	76.0	114.0
	Water Pollutants (tons)		
11.	Dissolved Solids b/	44,455.2	66,739.7
12.	Suspended Solids	23.2	37.7
13.	Other	448.0	728.0
	Process Sites		
14.	Land Use, permanent (acres) a/	.8	1.2
15.	Process Water Used (acre/ft)	5,690.0	8,535.0
16.	Solid Waste (tons) b/	12.0	18.0
	Air Pollutants (tons)		
17.	Particulates	207.2	310.8
18.	SO2	797.6	1,196.4
19.	NOx	210.0	315.0
20.	Hydrocarbons	2.2	3.0
21.	CO	5.2	7.9
	Water Pollutants (tons) b/	20.0	30.0
	Generating Site		
22.	Land use, permanent (acres) a/	323.6	523.9
23.	Process water used (acre/ft)	4,404.0	6,760.5
24.	Solid Waste (tons)	149,656.0	243,191.0
	Air Pollutants (tons)		
25.	Particulates	3,641.6	1,479.4
26.	SO2	4,036.0	6,558.5
27.	NOx	3,729.6	6,060.6
28.	Hydrocarbons	190.4	309.4
29.	CO	602.4	978.9
30.	Other b/	.4	.6
	Water Pollutants (tons)		
31.	Dissolved Solids	6,988.0	11,355.5
32.	Suspended Solids	2.6	4.3
33.	BOD	11.2	18.2
34.	COD	1,097.6	1,783.6
35.	Nitrates	15.2	24.7
36.	Other b/	95.6	143.4

a/ This represents total permanent disturbance and is not on an annualized basis.

b/ Denotes radioactive materials included.

In contrast to these environmental effects that would not occur because of the avoided generation, the proposed and LRIC alternatives would result in environmental effects from the conversion to alternative energy sources. The general environmental effects of alternative energy sources are described in the previous discussion of the 1982 revenue level alternatives. The cumulative revenue level alternatives would have similar effects but to a greater extent.

Other environmental effects of the cumulative revenue level alternatives would again occur in the agricultural sector. Adopting the proposed and LRIC alternatives would result in 79,000 and 769,000 fewer acres under sprinkler irrigation in the year 2000 than would the no action alternative. Depending on the location and concentration of these acres within the region, there could be environmental benefits from lower amounts of water withdrawals, reduced siltation and less pesticide use as a result of these acres not being sprinkler irrigated.

Again, the cumulative effects of the proposed or LRIC revenue level alternatives for the period 1979-1985 are not expected to alter operation of the hydroelectric system. Consequently, the alternatives would not effect the use and resources of the Columbia River and its tributaries.

D. Rate Design Alternatives

The process of electric utility ratemaking involves consideration of several rate design objectives. BPA, as a Federal power marketing agency, is a nonprofit organization having different rate design objectives than investor-owned or consumer-owned utilities. BPA is obligated to collect sufficient revenues to recover all its costs and is mandated to seek the lowest possible rates to consumers consistent with sound business principles.

The basic rate design objectives BPA follows in designing its wholesale power rates include: (1) ensuring adequate revenues to meet its repayment obligation; (2) meeting the revenue requirements while distributing the burden in an equitable manner among recipients of the service; (3) designing rates to encourage conservation and minimize environmental impacts; and (4) designing rates to encourage efficient use of the resources that it markets by reflecting costs incurred and benefits received. Additionally, consideration is given to rate continuity, ease of administration, revenue stability, and ease of understanding.

BPA's existing "Wholesale Power Rate Schedules and General Rate Schedule Provisions" are available from BPA upon request and will not be described in detail here. The existing schedules will be discussed in general terms as necessary to provide a comparative analysis of the proposed rate schedules. The proposed rate schedules are twelve in number. Each new rate, designated by a "2", is intended to replace an existing rate schedule, designated by a "1".

For the 1982 rate proposal, there are three new rate schedules (SP-1, SE-1, and EB-1) and two of the existing rates have been combined into one schedule (IP-2(MP-2)).

In each of the following sections that address BPA's twelve proposed rate schedules, discussions are included on the proposed rate relative to (1) any previously existing rate, and (2) reasonable alternatives to the proposed rate designs. A comparison of the environmental consequences of the proposed rates and alternatives also is presented. These discussions will not address alternatives to BPA's proposed CE-2, RP-2, FE-2, SI-2, SP-1, SE-1, and EB-1 rate schedules. It is not anticipated that significant amounts of revenue will be derived from sales under these rates or that they have the potential for significant environmental effects. Alternative rate designs for all other rates currently offered and proposed by BPA will be addressed. These include the Priority Firm Power Rate, PF-2; Wholesale Firm Capacity Rate, CF-2; New Resources Firm Power Rate, NR-2; Nonfirm Energy Rate, NF-2; Industrial Firm (Modified Firm) Power Rate, IP-2 (MP-2).

1. Priority Firm Power Rate, PF-2

a. Existing Rate

The PF rate schedule is for sale of firm power to be used within the Pacific Northwest by public bodies, cooperatives, Federal agencies, and IOU's participating in the residential and small farm exchange under Section 5(C) of the Regional Act. This rate schedule contains both a demand and an energy charge. The demand charge for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m., is $2.80 per kilowatt of billing demand. The demand charge for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m., is $1.44 per kilowatt of billing demand. There is no demand charge for all other hours of the year. The energy charge is 7.4 mills per kilowatthour of billing energy for the billing months September through March, and 6.9 mills per kilowatthour for the billing months April through August.

Adjustments to the rate include an adjustment that reduces the monthly demand charge by $0.257 per kilowatt of billing demand for customers purchasing at-site firm power under existing contracts, a low-density discount that may be applied to that portion of the customer's bill resulting from purchases under the PF-1 rate schedule, and an adjustment to encourage customers to match their power factor to their loads to permit efficient operation of the transmission system.

b. Proposed Rate

The basic proposed rate design remains the same as the existing rate. There is no longer an at-site power adjustment. There is a new adjustment for exchange costs that will allow BPA to collect all exchange costs that have not been collected through the rates. The adjustments for low-density discount and power factor continue in the proposed rate.

The proposed rate schedule contains increases in both demand and energy charges. The demand charge for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m. is $4.75 per kilowatt of billing demand. The demand charge for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m., is

$2.39 per kilowatt of billing demand. There is no demand charge for all other hours of the year. The energy charge is 12.9 mills per kilowatthour of billing energy for the billing months September through March, and 12.1 mills per kilowatthour for the billing months April through August.

c. Alternatives

BPA has considered two alternative rate designs to a uniformly applied priority firm power rate. In one case the rate is differentiated on the basis of the amount of energy consumed per end-use customer. In the other case, the rate varies from one class of customer to another depending on differences in the price elasticity of the classes. The first alternative will be addressed as the "tiered rate" alternative. The second will be termed the "inverse elasticity" alternative.

(1) Tiered Rates

Tiered rates involve the application of different rates to specific blocks of electricity consumption by customers. For example, the initial block of consumption would be charged a lower price than subsequent blocks. The determination of the amount of power to be sold at lower (base) rate can depend on a variety of factors. The baseline (BPA, 1979b) amount may reflect an attempt to represent basic needs such as cooking, lighting, refrigeration, and possibly heating. For example, BPA could sell to a utility, at BPA's baseline rate, an amount of power sufficient to meet the fundamental needs of each of the utility's retail customers. All additional sales to that utility would then be made at the higher second tier rate. Alternatively the base rate may reflect the relative amounts of power available from comparatively inexpensive hydropower facilities versus high cost thermal generation resources. It also could reflect a differentiation between existing load and load growth as of a given date.

Proponents of tiered rates have based their advocacy primarily on two assumed effects. First, it is claimed that a tiered rate may produce a more equitable method of cost recovery than a uniform or flat rate structure. The reasoning behind this conclusion is that customers using electricity in amounts beyond that required to meet basic needs are causing a demand for additional generation beyond that necessary to serve only basic needs. It is further argued that since this usage is presumably of a luxury nature, and since the additional generation required to meet this demand is relatively costly, the rate applied to such consumption should fully reflect the cost of the additional facilities.

The second argument advanced in favor of tiered rates is that they have a potential for encouraging conservation. It is suggested that consumers will be more sensitive to their marginal than to their average cost of electricity. Thus, a tiered rate would be presumed to produce a conservation response, relative to a uniform rate, since most consumers' marginal costs would be greater under tiered pricing than under uniform pricing. No systematic empirical evidence currently exists which would confirm a conservtion effect for tiered rates at the wholesale level. Tiered rates may also lessen revenue stability and, in BPA's case, may result in duplication of the billing credits BPA must offer under the Regional Power Act. A further discussion of these matters is presented in Appendix B of BPA 1982 Wholesale Power Rate Design Study.

(2) Rate Reflecting Application of the Inverse Elasticity Rule

In discussing alternatives to the proposed revenue level, the option of basing revenues on LRIC pricing was discussed. The justification for considering this alternative is that economic theory holds that LRIC pricing would result in an economically optimum distribution and consumption of resources. BPA's current marketing authority precludes collection of the large amount of excess revenue which would result from marginal cost pricing. However, in light of this revenue constraint, many economists suggest that rates reflecting the application of the inverse elasticity rule are the second best means of achieving an efficient distribution of resources.

Under the inverse elasticity approach, customers most responsive (highly elastic) to an increase in the cost of electricity would be charged rates closer to incremental cost than those rates charged less elastic customers. More specifically, the ratio of the elasticity of one customer to that of another should equal the inverse of the ratio of the respective quotients for each customer of (1) the difference between marginal cost and the price charged the customer, and (2) the price charged the customer (BPA, 1981d).

In order to apply the inverse elasticity rule to classes of customers it is necessary to have reliable elasticity estimates for each of the classes concerned. The availability of reliable elasticity estimates for BPA's customer classes is a potential obstacle to employment of this approach to rate design.

d. Comparison of Consequences

Rate design may have the potential to influence both the amount and type of additional generation required to meet future regional load growth. To the extent rate design can limit increases in the consumption of electricity, the impacts associated with new generation facilities can likewise be limited. To the extent that rate design can influence the types of resources developed to meet load growth, the impacts of meeting that growth can be altered.

Rate design also has the potential for effecting the distribution of socioeconomic impacts associated with purchasing electricity. The existing flat rate charges the same for all classes purchasing under the PF schedule. Both of the tiered and inverse elasticity alternatives would differentiate the rates based on certain consumption characteristics. In each case, however, the goal would be to achieve an increase in the efficiency of electricity use. Therefore, these designs may have the potential to lessen the overall negative socioeconomic impact of increasing rates.

In the Northwest, the capability of the region's hydroelectric system peaks in the spring and early summer as the result of snow melt, whereas the demand for electricity peaks during the winter heating season, necessitating additional generation or purchases of power. Differentiating the rates so as to charge higher rates during periods of high demand, reflecting parallel variations in the cost of generating the electricity, encourages a consumption pattern that permits more efficient operation of the FCRPS. This efficiency could minimize the future need for construction of additional generating facilities. Therefore, the seasonally differentiated feature of the existing rate design has potential environmental benefits because negative physical and socioeconomic impacts related to construction and financing of additional facilities could be postponed or avoided.

The seasonal differentiations under the rate, with a lower charge in June through November, also are beneficial to the region's irrigators and may encourage continued irrigation operations and possibly continued growth of irrigated agriculture. Whereas this may be viewed as a positive socioeconomic effect, irrigated agriculture carries the potential for creating certain negative physical effects in the form of increasing the introduction of silt, pesticide, and fertilizer runoff into the rivers and changes in land use.

Finally, the existing rate contains a diurnally differentiated demand charge which has potential for discouraging consumption of electricity during peak periods. The average cost of generation needed to provide electricity during the peak period is greater than during the offpeak period as additional relatively high cost facilities have to run to meet peak demand. Time-differentiated rates could lessen the need for construction of additional peaking capacity, but would not necessarily relieve the need for additional energy supplies. Therefore, although there would be some positive physical environmental effects associated with the decreased need for construction of peaking facilities, this design feature would not preclude major negative impacts associated with the future construction of additional baseload generation facilities.

2. <u>Firm Capacity Rate Schedule, CF-2</u>

a. <u>Existing Rate</u>

The CF rate schedule applies to capacity sales to utilities on a contract year and/or seasonal basis. The energy component associated with the delivery of capacity is returned to BPA.

Application of the basic rates for contract year service and contract season service is as follows: (1) billing of the contract year service of $25.44 per kilowattyear is rendered monthly by charging one-twelfth ($2.12 per kilowattmonth of contract demand) of the annual charge for capacity under the PF-1 rate schedule; (2) similarly, billing for the contract season service is done monthly at one-fifth of the seasonal rate of $11.76 per kilowatt per season ($2.35 per kilowattmonth of contract demand). The rate for contract season service (June 1 through October 31) is based on the costs as allocated in BPA's Cost-of-Service Analysis.

To encourage capacity purchasers to limit their use of Federal generating facilities, the CF rate schedule includes a provision for an additional monthly charge ($0.029) if capacity use is in excess of 9 hours per day. The rationale for this additional charge is that the Federal hydro peaking system cannot produce as much capacity during daily sustained hourly periods (in excess of 9 consecutive hours) as it can for shorter periods (less than 9 hours). When the FCRPS produces capacity for extended periods, its ability to meet firm commitments is reduced. Moreover, the return of inordinate amounts of energy during offpeak hours has the potential to place the Federal system in a spill condition and thereby reduce the economic utilization of the FCRPS hydro resources.

b. Proposed Rate

The proposed rate design remains the same as the existing rate. The proposed rate schedule contains increases in all charges. Application of the basic rates for contract year service and contract season service is proposed as follows: (1) billing of the contract year service of $42.84 per kilowatt per year is rendered monthly by charging one-twelfth ($3.57 per kilowatt per month of contract demand) of the annual charge; (2) similarly, billing for the contract season service is done monthly at one-fifth of the seasonal rate of $17.76 per kilowatt per season ($3.55 per kilowatt per month of contract demand). The capacity charge for annual or seasonal service will be increased by $0.04 per kilowatt per month of billing demand for each hour and each portion of an hour that the customer's monthly demand duration exceeds 9 hours. 9/

c. Alternatives

An alternative to the variable capacity rate in BPA's existing firm capacity rate would be a fixed rate based on the cost of resources required to provide the service. Such a rate would reflect the average cost of providing capacity and would ignore the duration of capacity purchases. It would provide no incentive to limit the duration of capacity purchases during the peak period.

Another alternative would be to offer a time-differentiated firm capacity rate resulting in a higher rate during peak than during offpeak hours. The peak period rate could be established at marginal cost, thereby providing a strong incentive to avoid extended purchases during the peak period. Excess revenues derived from peak period sales at marginal cost could be credited against costs associated with fixed contracts and the DSI value-of-reserves credit.

d. Comparison of Consequences

The design of the existing firm capacity rate encourages a consumption pattern that permits efficient operation of the FCRPS, therefore minimizing the future need for construction of additional peaking facilities. One of the alternatives considered would charge a time-differentiated rate resulting in a higher peak period rate. This design would have approximately the same effect as the variable charge of the existing rate with regards to the operation of the FCRPS. Therefore, there would not be significant environmental differences between this alternative and the existing rate design.

The other alternative considered was a fixed rate based on the cost of service. This rate would fail to achieve the gains in efficiency of operation of the FCRPS presumably achievable by either time-differentiation of rates or a peak use surcharge. This could result in the need for construction of additional peaking capacity and the negative physical and socioeconomic impacts related to construction and financing of these facilities.

3. Emergency Capacity Rate, CE-2

a. Existing Rate

The CE rate covers emergency capacity provided to utilities on a weekly basis when available. Return of energy associated with the delivery of this capacity is required. BPA will provide short-term capacity sales only when an emergency condition exists as defined by BPA's General Contract Provisions (Section 24 "Uncontrollable Forces") and when BPA has capacity available.

Application of the basic rate is as follows: (1) billing of the contract week service of $0.56 per kilowattweek is rendered monthly; (2) billing for deliveries over the intertie of $0.22 per kilowattweek is rendered monthly.

b. Proposed Rate

The proposed rate design remains the same as the existing rate. The proposed rate schedule contains increases in all charges. Application of the proposed basic rate is as follows: (1) billing of the contract week service of $0.95 per kilowattweek is rendered monthly; (2) billing for deliveries over the intertie of $0.36 per kilowattweek is rendered monthly.

c. Comparison of Consequences of Existing and Proposed Rates

It is not anticipated that there will be significant environmental differences between the existing and the proposed rates.

4. New Resources Firm Power Rate, NR-2

a. Existing Rate

The NR rate schedule is available for the purchase of firm power for resale or for direct consumption by purchasers other than DSI customers (who take power under rate schedules IP and MP). It is available for sale to the IOU's to serve any of their firm power deficits in the year prior to December 5, 1980, plus any IOU load growth, and new large single loads of public body, municipal, or cooperative utilities.

The NR-1 rate schedule contains both a demand and an energy charge. The demand charge for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m., is $2.80 per kilowatt of billing demand. The demand charge for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m., is $1.44 per kilowatt of billing demand. For all other times there is no demand charge. The energy charge is 30.8 mills per kilowatthour of billing energy for the billing months September through March, and 24.7 mills per kilowatthour for the billing months April through August.

b. Proposed Rate

The proposed NR-2 rate has been constructed in such a way as to resolve some of the uncertainty associated with the IOU's purchasing net requirements from BPA. Currently, no customer purchases under NR-1. The amount of IOU requirements load to be placed on BPA is dependent on the level of the NR-2 rate. However, the amount of resource and, therefore, the costs BPA must incur and collect from NR-2 is dependent on the amount of IOU net requirements placed on BPA. Therefore, there is a circular cause and effect relationship. To resolve this problem, the NR-2 rate is constructed with a base rate which is based on a block of the lowest cost resources assigned as serving the New Resources load. The NR-2 rate is equal to the base rate until the total purchases exceed the annual average output of the lowest cost resources. Thereafter, the NR-2 rate will increase as the IOU requirements load increases and BPA must purchase additional resources to serve the load. The NR-2 rate will be calculated under three circumstances: (1) at the beginning of the operating year; (2) when a new customer starts purchasing under NR-2; and (3) when BPA has surplus firm resources. The first two rate calculations occur when there are major changes of the load to be served under NR-2. In the third instance when BPA has surplus firm resources that are lower cost than a part of the resources that originally went into calculating the NR-2 rate, the NR-2 rate will be recalculated substituting the lower cost resources for the previously assigned resources. The higher cost resources that are no longer in the NR-2 rate will be available for sale as surplus firm resources.

The demand charge for NR-2 is the same as for the priority firm rate schedule: $4.75 per kilowatt of billing demand during winter peak hours and $2.39 per kilowatt of billing demand during summer peak hours. There is no demand charge for offpeak hours. The energy charge, if the total purchases of all customers under this rate schedule are less than or equal to 316 average megawatts, shall be: 29.5 mills per kilowatthour of billing energy for the winter period and 27.2 mills per kilowatthour of billing energy for the summer period. If the total purchases of all customers under this rate schedule exceed 316 average megawatts, the energy charge will be determined from the energy costs recovered in the above energy charge plus the energy costs of additional resources.

The NR-2 rate schedule includes an adjustment for power factor and exchange.

c. Alternatives

One alternative to the proposed NR-2 rate would be to maintain uniform seasonal energy charges based on averaging the energy costs of all new resources acquired by BPA. The demand charge would be the same as under the proposed NR-2 rate; however, the summer energy charge would be 35.6 mills per kilowatthour and the winter energy charge would be 38.9 mills per kilowatthour. These energy charges are substantially above those which would be employed for marketing up to 316 average megawatts of new resources firm power under the proposed NR-2 rate schedule.

The primary problem with this first alternative to the proposed NR-2 rate is that the energy charges would be so high as to cause the power to be virtually unmarketable.

A second alternative would be to market power from new resoures under two levelized (uniform) rates. The first would reflect the cost of the lowest cost resources currently assigned to serve new resources firm loads. This rate would be applied to all new resources firm loads. The second rate would reflect the cost of BPA's most costly new resources (i.e., renewable resources) the output of which would be marketed as surplus power.

Problems with this second alternative are twofold. First, the rate established for supplying new resource firm loads would be low enough so that the demand for this power would exceed the capability of the available lowest cost new resources, creating an underrecovery of costs. Second, output from the remaining relatively high cost renewable resources would be very expensive and not marketable, thereby resulting in unrecoverable resources costs or precluding the acquisition of such resources.

d. Comparison of Consequences

The environmental consequences of the NR-2 rate and its alternatives could vary somewhat, although none of the cases would be expected to have more than a very minor effect on the environment. Since the uniform energy charge approach would propably prevent new resources firm power sales, it would also eliminate the small localized effects associated with BPA's acquisition and operation of new resources.

The low cost/high cost approach could create increased demand for service which would increase the impacts associated with construction and operation of new resoures.

The proposed alternative would create effects whose magnitude would fall between those of the two previously discussed alternatives, since it would be likely the same sales of new resources firm power would be made, however, these would be somewhat limited due to the increase in the energy charges which would accompany growth in the demand for new resources firm power.

5. Nonfirm Energy Rate Schedule, NF-2

a. Existing Rate

BPA's existing NF rate represents a departure from the 1979 share-the-savings rate design. The share-the-savings concept is a pricing mechanism that attempts to reconcile the difference between the cost of energy to the seller and the value of energy to the purchaser by establishing a price between the two. The existing NF-1 nonfirm energy rate is designed to reflect the costs of resources used to produce Federal nonfirm energy. Therefore, operational considerations are the basis of this rate design.

The rate for nonfirm energy sales is based on the average cost of transmission, at 2.0 mills per kilowatthour, plus one of the following: (1) the diurnally-differentiated average cost of power from hydroelectric facilities, which is 4.5 mills per kilowatthour during the period Monday through Saturday, 7 a.m. through 10 p.m.; and 3.0 mills per kilowatthour for all other hours of the year, or (2) the cost of a power purchase in mills per kilowatthour incurred since the preceding July 31, or since the last time that all FCRPS reservoirs were substantially full, or (3) BPA's cost of other resources in mills per kilowatthour operated since the preceding July 31, or since the last time that all FCRPS reservoirs were substantially full, or (4) a weighted average in mills per kilowatthour based on cost from the preceding categories.

For contracts that refer to the nonfirm energy rate schedule for determining the value of energy, the rate is 9.6 mills per kilowatthour.

b. Proposed Rate

This rate would be for the purchase of nonfirm energy both inside and outside the Pacific Northwest, and also for energy delivered for emergency use under the conditions set forth in Section 5.1 of the General Rate Schedule Provisions. This rate would not be for the purchase of energy that BPA has a firm obligation to supply.

The price per kilowatthour for the NF-2 rate would be set according to the following three conditions. More than one condition may apply at any given time.

(1) A standard rate would apply at all times except under conditions when 2 below applies. It reflects the average cost of power, at 20.5 mills per kilowatthour.

(2) A spill rate could be applied to all sales of energy when a spill or imminent spill condition exists at one or more FCRPS hydroelectric plant as a result of excess energy on the FCRPS. This rate would be time-differentiated as follows: 10.0 mills per kilowatthour during the period Monday through Saturday, 7 a.m. through 10 p.m.; and 8.5 mills per kilowatthour for all other hours of the year. This rate would not be in

effect when the Federal system is spilling for reasons other than an excess of energy such as fish operations.

(3) An incremental rate could be used for displaceable power produced concurrent with a nonfirm sale. When the incremental cost of that displaceable power is greater than that specified in the Standard Rate above, the rate will be equal to the incremental cost of that displaceable power plus a factor of 15 percent but not to exceed the fully distributed costs of the resource being sold.

c. Alternatives

One alternative to the proposed NF-2 rate would be to leave the structure as it was in the NF-1 schedule which was based on a fixed cost of transmission plus one of four cost differentials designed to reflect the costs of resources used to produce nonfirm energy. Another alternative would be to revert to the share-the-savings rate design used in the 1979 rate schedule (the H-6 rate). This rate was based on the cost of the resources the customers were running and not on BPA's own operating cost, except that a floor and ceiling were established. A final alternative considered was a single flat rate, without adjustments for spillage or operating cost.

d. Comparison of Consequences

The proposed NF-2 and the three alternative designs considered vary in potential environmental consequences. The alternative (and existing) NF-1 design probably allowed BPA the most flexibility, in terms of rate levels and ability to respond to water and market conditions. This flexibility could conceivably influence both physical and socioeconomic environmental impacts. The proposed NF-2 rate has lost some of the flexibility to respond to market and water conditions, and therefore, could conceivably have less of an influence on physical and socioeconomic environmental impacts.

The share-the-savings alternative design (H-6) was designed to displace high-cost thermal resources, which could be accompanied by a reduction of generation associated environmental impacts. None of the other nonfirm energy rate designs are so targeted at reducing generation from specific resources.

Finally, the flat rate design alternative offers no flexibility to respond to water and market conditions and therefore distorts the economics by ignoring the current operating characteristics. Further, the level at which the rate would be set could have an environmental impact. For example, if set too high, a flat rate could preclude the sale of nonfirm energy, thus forcing BPA to spill water and waste energy. A high fixed rate could also be a disincentive to the purchase of nonfirm energy from BPA. In instances when the nonfirm energy would have been purchased to displace relatively high cost thermal plants, the result of too high a flat rate level could be increased pollutant levels associated with the thermal generation.

6. Reserve Power Rate Schedule, RP-2

a. Existing Rate

The RP schedule is available for the purchase of (1) firm power to meet a purchaser's unanticipated load growth as provided in a purchaser's power sales contract; (2) power for which BPA determines no other rate schedule is applicable; or (3) power to serve a purchaser's firm power loads in circumstances where BPA does not have a power sales contract in force with the purchaser and BPA determines that the rate should be applicable.

The existing reserve power rate is based directly on the results of the Long Run Incremental Cost Analysis and the Time-Differentiated Pricing Analysis of long run incremental costs. This rate includes a demand charge that is time-differentiated both diurnally and seasonally. The demand charge for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m., is $12.57 per kilowattmonth of billing demand. The demand charge for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m. is $3.47 per kilowattmonth of billing demand. There is no demand charge during other hours of the year. The energy charge is 62.1 mills per kilowatthour and is applicable all hours of the year. The RP rate includes an adjustment for power factor.

b. Proposed Rate

The proposed rate design remains the same as the existing rate. For this rate filing the Long Run Incremental Cost Analysis and the Time-Differentiated Pricing Analysis has been combined into one analysis, the Time-Differentiated Long Run Incremental Cost Analysis. The proposed rate schedule contains decreases in all charges.

The reserve power rate includes a demand charge which is time-differentiated on both a daily and seasonal basis. The demand charge for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m., is $9.95 per kilowatt of billing demand. The demand charge for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m., is $4.96 per kilowatt of billing demand. There is no demand charge during other hours of the year. The energy charge is 43.9 mills per kilowatthour and is applicable all hours of the year. The RP-2 rate includes an adjustment for power factor.

c. Comparison of Consequences of Existing and Proposed Rates

It is not anticipated that sufficient sales would occur under this schedule to create a significant environmental effect regardless of the design of the rate.

7. Firm Energy Rate Schedule, FE-2

a. Existing Rate

This rate is designed to serve the requirements of contract purchasers of firm energy in the amounts and during the periods specified in the contracts. The rate is based on the application of the PF-1 rate assuming 100 percent load factor.

The rate for wholesale firm energy is 10.0 mills per kilowatthour for all hours of the year. An adjustment for power factor also is included in the FE-1 rate.

b. Proposed Rate

The proposed rate design remains the same as the existing rate with the addition of an exchange adjustment.

The rate for wholesale firm energy is 17.5 mills per kilowatthour for all hours of the year.

c. Comparison of Consequences of Existing and Proposed Rates

It is not anticipated that sufficient sales would occur under this schedule to create a significant environmental effect regardless of the design of the rate.

8. Industrial Firm and Modified Firm Power Rates, IP-2 and MP-2

a. Existing Rates

The existing IP and MP rate schedules are two separate rate schedules for the sales of Federal power to BPA's direct-service industrial customers. In developing these rates it was assumed that a portion of the power needed by the DSI's would be provided by Federal base system resources and the remainder by exchange resources acquired from participating utilities. Consequently, the rates were based on costs from two resource pools. The demand and energy charges of the IP-1 and MP-1 rate schedules are time-differentiated similarly to those of schedule PF-1.

BPA offered two power rate schedules, IP-1 and MP-1, to DSI customers to allow for billing differences associated with the two types of contracts available to these customers. Although the IP-1 and MP-1 rate schedules share many common features, significant differences occur in the areas of power availability, the value of reserves adjustment, and advance of energy.

A value of reserves adjustment was included under the IP-1 rate schedule, but not under the MP-1 schedule, because of the differences in the quality of power available under the two rate schedules and in the associated contracts. The DSI customers provide BPA with reserves through the interruptible provisions contained in the interim contracts which are associated with the IP rate. In general, BPA can interrupt the top quartile of the industrial load at any time for any reason for service of the Administrator's other firm loads. Another 25 percent can be interrupted to offset loss of power due to delays in construction or the inability to operate new generating projects. Additional restrictions can be made for forced outages and/or to maintain system reliability. BPA has fewer restriction rights under the MP contracts. To determine the value of reserves, BPA categorized and analyzed three types of reserves: operating reserves, planning reserves, and stability reserves. A value-of-reserves rate adjustment which totals $76 million is included under the IP-1 rate schedule in the form of a uniform reduction in the monthly demand and energy charges. The adjustment is $1.18 per kilowatt of billing demand and 1.2 mills per kilowatthour of billing energy.

Finally, the delivery of advance energy and the obligation for its potential return was provided for under the IP-1 rate schedule but was not available under the MP-1 rate schedule. Advance energy was a limited amount of power delivered during periods when BPA restricts industrial firm power. The power must be returned if the energy was needed to serve other firm loads. If excess water flows occur and reservoirs refill or are operated for flood control, then the obligation to return the advance energy was waived. Return of advance energy to BPA, when required, could occur either through the purchase by the obligated customer of energy from a source other than BPA or through a reduction in load by the obligated customer. In either case, BPA's ability to serve its other firm loads remains unchanged.

The demand charges for the IP-1 and MP-1 rates are the same as the demand charges for the existing priority firm rate. The winter peak charge is $2.80 per kilowatt of billing demand, the summer peak charge is $1.44 per kilowatt of billing demand, and there is no demand charge during offpeak hours. The energy charge is equal to BPA's existing firm energy charge plus an amount sufficient to recover the cost of exchange power acquired under the residential and small farm exchange program. The formulas used in calculating the energy charge are the greater of: (1) for the billing months of September through March, 7.4 mills per kilowatthour of billing energy; for April through August, 6.9 mills per kilowatthour of billing, or (2) for the billing months September through March, [1.7 + (X/2465)] mills per kilowatthour of billing energy; for the months of April through August, [1.6 + (X/2480)] mills per kilowatthour of billing energy (where X equals the actual month's cost in thousands of dollars incurred by the Administrator pursuant to Section 5(c) of the Regional Act). A value-of-reserves rate adjustment was included under the IP-1 rate schedule in the form of a uniform reduction in the monthly demand and energy charges. The adjustment is $0.33 per kilowatt of billing demand and 2.1 mills per kilowatthour of billing energy.

b. Proposed Rate

The IP and MP rates have been combined into one rate schedule. Most DSI customers are currently operating under new 20-year contracts which incorporate provisions of the Regional Act and the IP-2 version of this rate schedule is available to these DSI's for the purchase of power; the MP-2 version is available to those DSI's who have not signed new contracts and wish to purchase power under their Modified Firm contracts.

There is a change in the value of reserves determination. BPA is basing its determination of the value of reserves provided by BPA's restriction rights on DSI load on combined cycle combustion turbines and an alternative load tripping scheme. The estimated annualized investment cost of constructing the turbines is $124 million per year for 20 years. BPA estimated the variable costs that would be incurred in FY 83 from operating the turbines to be $1 thousand based on average water. Stability reserves are valued at $0.8 million per year, based on an alternative load tripping scheme. BPA's analysis of the value of reserves appears as Appendix C to the Wholesale Power Rate Design Study.

The cost of the outages to the DSI's in FY 83 was estimated to be $0.2 million. A share the savings approach was used to calculate the value of reserves credit which resulted in a credit of $62.5 million. The credit was to be classified via the reverse of the LRIC classification percentages of the fixed components of generation costs or 76 percent to capacity and 24 percent to energy. This was to be done in order to maintain the proper price signal to the DSI's. However, an error was found in which the percentages were switched, i.e., 24 percent was classified to capacity and 76 percent was classified to energy. This error will be corrected in the final proposal. The credit is in the form of a uniform reduction in the demand and energy charges in the same manner as the current IP-1 rate schedule.

Service to the DSI's under the Regional Act is for power subject to interruption in order to serve BPA's other firm loads. As part of the service to the DSI's, BPA is to plan and acquire sufficient firm resources to satisfy three quarters of the DSI load. The remaining one quarter, referred to as the "top quartile" is treated as firm load for operating purposes only. The top quartile is a quasi-firm load, to be served by operating resources in such a manner as to produce a quantity of power with firm characteristics for six months, while not installing additional resources to meet it on an absolute firm basis. If planning or operating shortages occur, service to the top quartile can be restricted in order to provide service to BPA's firm load.

There are four portions to the DSI top quartile service. First, there is service with shifted Firm Energy Load Carrying Capability (FELCC). FELCC is a planning device provided for under the Pacific Northwest Coordination Agreement of 1964 to permit maximum flexibility in the use of the region's hydro and thermal resources. In general, it is the shaping of reservoir draft (depth) from one year to another in anticipation of greater than critical level streamflows over a 4-year period. In practice this means that reservoirs are drawn down to an earlier and deeper draft than otherwise would be permitted. If normal or better than average rainfall occurs, the reservoirs operate as anticipated, and other resources operate as anticipated, the reservoirs will refill. There is risk involved in shifting FELCC if the better than critical streamflows do not materialize which may result in BPA"s restriction of power to the top quartile and possibly the pulling back of an equivalent amount of power from the second and third quartile in later periods to compensate for the borrowed FELCC.

A second portion of the service to the top quartile is nonfirm energy. Nonfirm energy is the extra energy produced from average streamflows versus critical period streamflows. Serving the top quartile would result in an additional usage of nonfirm energy. Since Northwest utilities can use nonfirm energy to serve their loads and either shutdown their higher cost (thermal) resources or sell power from their high cost resources to the Pacific Southwest, this could perhaps result in the displacement of fewer firm thermal resources.

Due to a recent court decision, preference customers have priority to nonfirm energy marketed by BPA. The court decision is subject to rehearing and possible appeal. However, to make its contracts with the DSI's consistent with the court's decision, BPA has offered DSI's contract amendments providing that the delivery of Industrial Firm Power for the DSI's top quartile loads pusuant to the provisions of Sections 7(c) and 8 (a)(2) of the DSI contracts, for the DSI's third quartile loads pursuant to section 7(e)(6) of the DSI contracts, and the conservation, recall, or acquisition of power to deliver, or avoid the restriction of Industrial Firm Power for the DSI's top quartile loads pursuant to Section 8(c)(9) will be subject to the preference and priority to be given to public bodies and cooperatives.

A third method of serving the top quartile also involves advancing energy from a later period into an earlier period. As with shifting of FELCC, the success of advancing energy is dependent of streamflow conditions. Provision for payback of advanced energy is made if streamflows are not above a critical level.

A final alternative to serving the top quartile is flexibility. Flexibility is the same as shifting FELCC, but is within one year rather than between years of the critical period. Flexibility can only be used within the constraints of the Coordination Agreement and must be paid back at a later time, if streamflows don't materialize.

Finally, a new provision is added to the IP-2 (MP-2) rate schedule to establish a minimum bill. The minimum bill is based on the forecasted annual revenues BPA would receive from the lower 3 quartiles of DSI load, divided by the total DSI operating demand, and divided by 12 months in a year which results in $11.56 per kilowatt per month of operating demand. The minimum bill provision was included in the IP-2 rate in order to stabilize BPA's revenues. The revenues from 3/4 of the DSI load was chosen as a basis because 3/4 of the DSI load is served as firm. That is, BPA has planned resources and incurred costs for those resources in order to serve DSI load. If BPA is able to sell its resources that are surplus, the Administrator may waive the minimum bill. If BPA restricts the DSI's such that the revenues BPA would have received from the bottom three quartiles adjusted for restrictions on the bottom three quartiles are less than the minimum bill, the minimum bill would be waived.

The demand charges for the IP-2 (MP-2) rate is the same as the demand charges for the priority firm rate. The winter peak charge is $4.75 per kilowatt of billing demand, the summer peak charge is $2.39 per kilowatt of billing demand, and there is no demand charge for the offpeak hours. The winter season energy charge is 19.5 mills per kilowatthour of billing energy and the summer season charge is 18.7 mills per kilowatthour of billing energy.

An adjustment for value of reserves is provided only under the IP-2 portion of the rate schedule. The adjustment is $0.38 per kilowatt of billing demand and 1.7 mills per kilowatthour of billing energy. Additional adjustments which apply to both industrial firm and modified firm power rates are a power factor adjustment and an exchange adjustment.

Finally, the IP-2 (MP-2) rate schedule is subject to a minimum bill provision. Payment for sales of power shall be the greater of the monthly calculated bill or a minimum bill. Such minimum bill will be $11.56 per kilowatt of monthly operating demand but may be adjusted by the exchange adjustment. The minimum bill provision may be waived at the discretion of the Administrator.

c. Alternatives

One alternative to both existing and proposed rates would be to eliminate any compensation to the DSI's associated with the restriction rights. Another alternative could be to provide some form of compensation to the DSI's in recognition of their reserves, but in an amount different from that provided under the IP rate.

The valuation process leading to the determination of the reserve credit employed in developing the existing IP rate is described in detail in BPA's 1981 Wholesale Power Rate Design Study.

Although variations can be considered for each of the steps in the valuation process the most significant alternatives are those involving the method used for assigning a value to the reserves. Whereas the value reflected in the proposed IP-2 rate is based on the captial cost of building and the energy cost of running combined cycle combustion turbines, it could be argued that a different valuation may have merit. An alternative would be to use BPA's 1983 average cost of power as a valuation basis. In essence this would reflect the fact that BPA would have purchased resources over the same time frame as purchasing resources to meet firm load. This rationale could be used to justify a value of reserves based on embedded cost. This alternative would produce a much lower value of reserves than a method employing incremental costs.

In addition to varying the basis for valuing the reserves, variations could be employed in the method for applying the credit. Whereas the proposed method involves granting a credit against the charge for each kilowatthour purchased by the DSI's, an alternative would be to offer a credit only when, and to the extent to which, BPA exercised its restriction rights. This approach could create cash flow problems for BPA in poor water years and fails to reflect the fact that the benefit of the reserves lies in their existence, whether or not they are used.

In addition to alternative methods for valuing the reserves and assigning a credit to the DSI's, variations in the form of the IP-2 rate could be employed. For example, a tiered rate structure could be developed under which top quartile sales could be made at a rate based on the average cost of BPA's nonfirm resources. The rate applied to all other DSI service could be based on costs of the firm resources assigned to serve them.

A primary problem with this tiered approach is that the DSI's have the option of curtailing below the first quartile before curtailing the first quartile when the first quartile is being served with shifted FELCC or advanced energy. This could contribute to a revenue stability problem for BPA. However, this approach could potentially serve to lessen BPA's exposure to revenue instability due to water conditions.

A second alternative rate form would be for BPA to apply a melded rate with no minimum bill provision to the DSI's. This would make BPA's revenue stability vulnerable to DSI load curtailments, however.

d. Comparison of Consequences

The primary environmental consequences of one or another of the pricing alternatives under discussion would be related to the effect of each alternative on the level of the DSI rate. Higher rates would be expected to result in greater curtailment of DSI loads which would reduce the impacts created by DSI operations and by operation of generation resources required to serve the DSI's. Higher rates may also have socioeconomic consequences affecting DSI employment levels, industrial output and overall financial status, as noted in Section VI (B)(2)(b).

9. Special Industrial Power Rate Schedule, SI-2

a. Existing Rate

Section 7(d)(2) of the Regional Act allows the Administrator to establish a special rate that need not be cost based, if any direct-service industrial customer using raw materials indigenous to the region would suffer adverse impacts of increased rates pursuant to the Regional Act and if all power sold to such a customer could be interrupted or withdrawn to meet firm loads in the region. Hanna Nickel Smelting Company (Hanna) has submitted information demonstrating that adverse impacts on Hanna's operations would have resulted from increased power costs had BPA's IP-1 rates been made applicable to its sales to Hanna.

Therefore, BPA proposed the SI-1 rate to serve Hanna, contingent upon acceptance by Hanna of a special class of power consisting of one-half nonfirm energy and one-half "junior firm" power. The SI-1 rate was essentially a cost based rate. The savings in purchased power costs associated with not serving the second quartile of the Hanna load with firm power are reflected as a reduction to the IP-1 rate, in arriving at the SI-1 rate. The structure of the SI-1 rate is the same as the IP-1 rate except that the SI-1 rate has both a floor and a ceiling. BPA included a surcharge in the Hanna contract to recover costs of serving Hanna that are not recovered through application of the rate if there are such nonreimbursed costs and if (1) Hanna's sales price for nickel increases and/or (2) the Hanna operation realizes profit.

The demand charge for SI-1 power for December through May, Monday through Saturday, 7 a.m. through 10 p.m., is $2.80 per KW of billing demand per month. For the months of June through November, Monday through Saturday, 7 a.m. through 10 p.m., the demand charge is $1.44 per KW of billing demand per month. During all other hours there is no demand charge. The energy charge is the greater of (1) 7.4 mills per kilowatthour of billing energy for the billing months September through March and 6.9 mills per kilowatthour of billing energy for the months April through August or (2) [(X/2465) - 4.8)] mills per kilowatthour for the months September through March and [(X/2480) - 4.9] mills per kilowatthour for the months April through August, where "X" equals the actual monthly costs in thousands of dollars incurred by the Administrator pursuant to section 5(c) of the Regional Act. The energy charge is not to exceed 10.6 mills per kilowatthour in any month, excluding any surcharges.

b. Proposed Rate

The SI-2 rate is based on the IP-2 rate with the same provisions and adjustments.

The SI-2 rate is calculated on the net of the additional costs, based on the TDLRIC Analysis, of 23.5 megawatts of resources which BPA would have incurred if Hanna had not agreed to additional interruptible provisions in its special contract and the loss of revenues from 23.5 megawatts being no longer available for nonfirm sales. This net is classified to demand and energy using the TDLRIC classification results for generation costs including fixed and variable costs of 19 percent to capacity and 81 percent to energy, then time differentiated via Hanna's billing determinants for winter and summer. This credit is subtracted from the total costs allocated to Hanna in order to derive the rate (Table 24). The SI-2 rate schedule has a minimum bill provision similar to the IP-2 rate. However, it is based on revenues from Hanna's bottom two quartiles.

c. Comparison of Consequences of Existing and Proposed Rates

The existing and the proposed rates have positive socioeconomic impacts by mitigating the adverse impacts on Hanna and its employees that would result from increased power costs if BPA were to apply its IP rates to Hanna. These positive impacts include maintenance of employment levels in an isolated part of the region without transferring significant cost to the remaining ratepayers.

10. Energy Broker Rate, EB-1

a. Existing Rate

BPA does not presently offer an energy broker rate.

b. Proposed Rate

In October 1981, BPA entered into an agreement with the Western Systems Coordinating Council (WSCC) to participate in WSCC's Energy Broker program. The broker program offered by WSCC is a communication and scheduling procedure for matching potential sellers of electric energy with potential buyers. A computer system (the energy broker) arranges selling and buying quotations between participating utilities and identifies all energy transactions. BPA will use the broker for energy sales only after all available markets have been served under the nonfirm energy rate schedule. Once nonfirm energy is offered on the Broker, public agency and regional preference will no longer be a factor in determining who will purchase nonfirm energy. Both buy and sell transactions are negotiated on an hourly basis and are interruptible immediately upon notification.

BPA may also act as a broker in the WSCC system for its customers when energy is desired to be sold by those customers on the Broker. Power sold in this manner would be from previously stored energy in the FCRPS and would not include service, storage, wheeling, or deration charges that BPA assesses its customers for storage service.

The WSCC agreement defines the BPA buy price quote as the estimated decremental or equivalent expense per kilowatthour which would otherwise have been incurred by BPA in generating or purchasing energy from alternative sources in lieu of broker energy scheduled for delivery to BPA during that hour. BPA's buy price quote is intended to be no less than the decremental cost of energy from alternative resources online that hour, or the decremental cost of energy available for purchase or being purchased that hour on a prescheduled basis. BPA may use the broker to purchase energy primarily to meet short-term energy requirements.

The WSCC agreement defines the BPA sell price quote as the estimated incremental or equivalent expense per kilowatthour which would be incurred by BPA in supplying broker energy scheduled for delivery during such hour to the buyer from resources which are available to supply energy during that hour as determined by BPA. BPA's sell price quote is intended to be no greater than the incremental cost of energy stored in the FCRPS, the incremental cost of operating thermal resources, or the incremental cost of energy purchases. Such stored, thermal or purchased energy quoted for sale would either be concurrently online to BPA on that hour or stored in the FCRPS on a prior hour. Cumulative balances of stored energy from the FCRPS used for sale on the broker system would be reduced when the energy quoted is sold. Again, nonfirm BPA energy would be offered for sale only when the nonfirm energy cannot be sold through BPA's normal scheduling process and BPA studies indicate that the energy would otherwise be spilled.

In practice, hourly energy transactions on the WSCC broker system between utilities and BPA may occur when the buyer's decremental (avoided) costs of reducing generation and purchased energy exceed the seller's incremental costs of increasing generation and purchased energy. The broker will identify potential transactions when the sell price is at least 2 mills per kilowatthour less than the buy price. The final transaction rate for brokered nonfirm energy will be based on splitting the difference between buy and sell prices. The responsibility for wheeling charges and energy losses to intermediate systems will be shared equally between BPA and participating utilities unless otherwise agreed and identified in the Energy Broker. Wheeling charges in mills per kilowatthour and energy losses will be in accordance with Exhibit A of the WSCC Broker Transmission Service

Agreement, with the settlement for wheeling charges based on energy received by the participant providing transmission service, and energy losses based upon the transaction price or a mutually agreed upon price not to exceed the transaction price.

c. Consequences of the Proposed Rate

The proposed rate is expected to insure maximum efficiency in the marketing and use of available generation resources and should, accordingly, facilitate minimization of the socioeconomic effects of the sale of the nonfirm energy being marketed. To the extent that the proposed rate insures marketability of energy which would otherwise be spilled, it also prevents development of environmental effects (e.g., nitrogen supersaturation) which could result from such spills.

11. Surplus Firm Power Rate Schedule, SP-1

a. Existing Rate

No BPA rate currently exists for marketing surplus firm power.

b. Proposed Rate

In FY 83 BPA may have firm surplus resources due to DSI load curtailments, priority firm load underruns, or over-forecasting of IOU net requirement loads under 7(f). The surplus firm power rate was created to sell any such firm power. The rate is based on the cost of the identified surplus resource, or, if the surplus is due to load curtailment and that load was identified as being served with exchange resources in the development of the rate filing, the rate will be equal to the cost of the exchange resources. In identifying a surplus resource other than exchange, the resource will be the highest cost marketable resource available to BPA. This rate schedule is available for purchases outside the United States.

This rate schedule is in two parts. The first part applies when a firm surplus can be identified due to curtailment or underruns of load that were identified as being served with exchange resources in the development of the rate filing. The demand rate is $4.75 per kilowatt of billing demand during the winter peak hours and $2.39 per kilowatt of billing demand during the summer peak hours. There is no demand charge for all other hours. The energy charge is 20.3 mills per kilowatthour of billing energy during the winter period and 19.4 mills per kilowatthour of billing energy during the summer period.

The second part is for purchase of firm surplus power from specified resources. The demand charge is the same as above and the energy charge is based on the annual costs of the resource that are not recovered by the demand charge plus 5 mills per kilowatthour for administrative and transmission costs. The SP-1 rate schedule includes an adjustment for power factor and exchange.

c. Consequences of the Proposed Rate

The firm surplus rate would permit BPA to market power from resources which would be surplus to BPA's regular loads. The revenue derived from such sales would mitigate the negative socioeconomic effects which would otherwise befall BPA's customers if the cost of such resources were to be recovered from them. However, the sale of surplus energy could contribute to generation impacts resulting from operation of surplus resources. It is not possible to quantify these impacts since the amount of resource involved cannot be predicted.

12. Surplus Firm Energy Rate Schedule, SE-1

a. Existing Rate

No schedule for the sale of surplus firm energy is currently offered by BPA.

b. Proposed Rate

Due to the nature of the FCRPS, it is possible to have firm surplus energy without surplus capacity. It is also possible to market surplus firm energy to capacity customers. Therefore, another rate schedule in addition to SP-1 was created for such situations. The rate is an energy charge based on the variable costs of an identified resource or resources plus 76 percent of the fixed costs plus 5 mills per kilowatthour of administrative and transmission costs. This classification percentage is the generation classification percentage of the energy portion of fixed generating costs as calculated in BPA's Time-Differentiated Long Run Incremental Cost Analysis. The identified resource will be the highest cost marketable resource or resources available to BPA. This rate schedule is available for sales outside the United States.

Delivery of energy under this rate schedule is assured during the contract period. However, BPA may interrupt the delivery of firm energy, in whole or in part, at any time that BPA determines that it is unable to deliver such energy because of system operating conditions. An adjustment for power factor is included in the surplus firm energy rate.

c. Consequences of the Proposed Rate

Since the SE-1 rate schedule would permit BPA to market surplus firm energy at a rate above its nonfirm rate, the amount of revenue required from other customers could be reduced. The amount of this reduction, although not known, is not likely to be of sufficient size to significantly affect the rates of other customers, however. It is not expected that this rate schedule has potential for creating a significant environmental impact.

E. Consultation, Review, and Permit Requirements

In addition to their responsibilities under NEPA, Federal agencies are required to carry out the provisions of other Federal environmental laws. Most of the Federal actions related to the proposed rate adjustment discussed in this EIS do not require any particular response with regard to the resources addressed in these other Federal laws because the requirements are more concerned with site-specific proposals and alternatives, rather than the broad rate decisions being analyzed in this document.

There are a number of these Federals laws which clearly do not apply to the braod rate decisions which BPA is currently considering. The rate proposal analyzed in this document does not recommend any actions which might jeopardize the continued existence of a listed species, a species proposed for listing, or the critical habitat of any listed or proposed species, pursuant to the Endangered Species Act . Floodplains and wetlands are protected by statutes which apply only to specific proposals for land use, resource planning, and construction and improvements. The rate proposal does not recommend that any farmlands be converted to other uses. BPA's wholesale rate alternatives do not include actions that would adversely affect recreation resources such as wilderness areas, parks, campgrounds, trails, and scenic areas.

No site-specific actions or recommendations are presented in the rates proposal which might affect navigable waters cause any discharges of dredged or fill materials, or require right-of-way permits. The rate alternatives examined in this EIS do not include the procurement of goods, services, or materials from a facility on the EPA's List of Violating Facilities.

The following laws were examined more closely to determine their application to BPA's 1982 wholesale rate proposal.

1. Coastal Zone Management Act

There must be a determination whether BPA's activities (the proposal and alternatives) "directly affect" the coastal zone. If these activities directly affect the coastal zone, a "consistency determination" is required.

In the BPA service area, two States have approved management programs: Washington and Oregon. No activities such as the BPA proposal and alternatives are listed in either the Washington State Coastal Zone Management Program (WSCZMP) or the Oregon Coastal Management Program (OCMP). Thus, the BPA proposal and alternatives do not directly affect the coastal zone as a result of a listing in an approved State management program.

An activity can be said to directly affect the coastal zone if the activity would be affected by the terms of the approved State management programs. The BPA proposal and alternatives are policy-oriented, not development-oriented, and are not affected by the WSCZMP or the OCMP.

2. Heritage Conservation

Impacts to properties on or eligible for the National Register of Historic Places are not included within the range of impacts caused by the proposed 1982 rate increase. While owners of these properties may undertake measures (i.e., weatherization) to mitigate economic effects of generally increasing energy costs, and while the measures may indeed have effects to the properties, it is not reasonably foreseeable that the 1982 rate increase in itself would generate these effects. Therefore, impacts to properties on or eligible for the National Register of Historic Places are outside the scope of this EIS and not considered further.

However, separate from the 1982 rate increase, BPA is proposing several conservation programs--including weatherization. In considering the environmental effects of these programs, BPA will consult with the Advisory Council on Historic Preservation and the State Historic Preservation Officers to determine effects on National Register or eligible properties and to develop means of avoiding adverse effects.

3. State, Areawide, and Local Program Consistency

Since the BPA rate alternatives do not involve direct Federal development (e.g., specific projects, disposition of real property, and technical assistance), State, regional, and local land use plans and programs will not be affected. However, to the extent that any of the alternatives would cause some socioeconomic impacts to State and local interests due to the cost of power, these impacts are analyzed in this EIS.

FOOTNOTES

1/ As defined in the Bonneville Project Act of 1937 and reaffirmed in the Regional Act, cooperatives and public bodies (states, public utility districts, counties, municipalities and Federal customers) have preferential rights to power generated from the FCRPS.

2/ For purposes of developing revised rates to take effect October 1982, fiscal year (FY) 1983 is the test year for which cost and load estimates are projected.

3/ For further discussion regarding the impacts of electricity price on regional generation resources see BPA, 1981a, Chapter III (B)(2)(c); BPA, 1979, Chapter IV(C) and (D).

4/ For a more detailed discussion of the impacts see BPA, 1979b; Fullen, et al. 1976, pp. 35-42.

5/ See Chapter VII for explanation of basic assumptions under which this number is generated.

6/ See Chapter VII.

7/ Revenue over or undercollection is possible in a given year or series of years and would either be returned to or collected from future ratepayers. This can happen depending on streamflow, temperature, power purchase, and/or other conditions that may affect a given year's power supply/demand situation. However, it is not a purposeful result of the design of the rates.

8/ Cost estimates adapted from: Electric Power Research Institute, 1979, Technical Assessment Guide, Palo Alto, California, July. Computations for conventional oil-fired generation costs based on data from: California Energy Commission, 1980, Estimating Utilities' Prices for Power Purchases from Alternative Energy Resources, Sacramento, California, March, p. 6.

9/ A customer's demand duration for the month is determined by dividing the number of kilowatthours supplied to the purchaser under the rate on the day of the purchaser's maximum use between 7 a.m. and 10 p.m. (excluding Sunday) by the purchaser's contract demand for the month.

VI. Affected Environment

This chapter briefly describes the environment of the region and highlights those aspects that are most likely to be affected by increases in BPA's wholesale power rates.

A. Regional Setting

The Pacific Northwest region consists of the states of Washington, Oregon, Idaho, and Montana west of the Continental Divide as shown in Figure VI-1 and generally defines BPA's service area. In addition, BPA sells to the Pacific Southwest nonfirm power that is surplus to the Northwest. While increasing wholesale power rates may have an impact on the Pacific Southwest region (and those impacts will be described in this EIS), the primary impacts would be on the Pacific Northwest region. The region is divided into six subregions according to similar environmental characteristics. These are the Puget Sound-Willamette Valley, the Columbia River Plateau, and the Snake River Plateau; these are separated by the Coast Range, the Cascades, and the Rocky Mountains.

The region's climate is generally mild. West of the Cascades the region is mild and wet year-round, while east of the Cascades the region typically receives no more than 15 inches of precipitation and temperatures vary more seasonally. The entire region receives less precipitation during the summer than during the rest of the year. Numerous streams, many of which feed the Snake and Columbia rivers, offer abundant opportunities for transportation, irrigation, commercial fishing, recreation, and the production of electricity.

Half of the region is forested. West of the Cascade Range the climate is particularly well-suited to the growing of trees with three-quarters of the area being covered by forest. East of the Cascades less than one-third of the area is forested. Range and agricultural land uses cover the second largest area of the region. Rangeland occupies substantial areas in the Snake River and Rocky Mountain subregions. Agricultural lands are located primarily on the Columbia River Plateau, along the Snake River, and in the Willamette Valley.

About two-thirds of the region is publicly owned with Federal ownership accounting for half of the region's land. The bulk of this property is managed by the U.S. Forest Service or Bureau of Land Management for forest and range uses. State and local governments own about one-sixth of the region and private ownership accounts for about one-third of the area.

The region's total population is about 8 million. The major population centers are Seattle-Tacoma, Portland-Vancouver, Eugene-Springfield, Spokane, and Boise-Nampa-Caldwell. During the past two decades, the region's population growth rate has exceeded the national average, with Oregon and Washington growing more rapidly than the rest of the region.

FIGURE VI-1

Bonneville Power Administration Service Area

Of this regional population about 3 1/2 million persons are employed. During the past 20 years the cyclical nature of the region's economy has caused the region's unemployment rate generally to be higher than that of the Nation as a whole. Within the region itself, Idaho usually has had the lowest unemployment rate and western Montana has had the highest. In the early 1970's Washington had the region's highest unemployment rate as a result of the recession in the aircraft industry. Presently, the entire region is experiencing high unemployment because of the nationwide recession.

About two-thirds of the region's labor force is employed in the areas of retail and wholesale trade, services, government, and transportation. Transportation activities have been particularly important to the region's economy. The modes include an interstate highway system, coastal and inland water traffic, railroad lines from the regional centers to the major ports, and air transportation between the major cities.

One-fourth of the regional labor force is employed in manufacturing and construction. The largest manufacturing employers are the lumber and wood products, transportation equipment and electronics industries, although the relative importance of these and other manufacturing industries vary considerably among the states. The availability of inexpensive electricity has been an important factor in the growth of certain industries in the region, particularly for chemical and primary metal production.

The remaining portion of the region's labor force is employed in agriculture, forestry, commercial fishing, and mining. Agriculture accounts for a much greater percentage of the labor force than does forestry, commercial fishing, and mining. With the construction of new irrigation facilities, more land is being brought into agricultural production throughout the region.

Regional electricity consumption varies geographically and seasonally. The Puget Sound-Willamette Valley subregion, which accounts for two-thirds of the region's population, uses the greatest amount of electricity. Within this subregion, electric energy consumption is highest during the winter when space heating needs are greatest. East of the Cascades, electric energy use tends to be highest during the summer because of irrigation pumping and air conditioning loads.

Use of electricity in the region also varies by the type of user (see Table VI-1). The industrial sector accounts for 43.73 percent of the electric energy consumed, with the electroprocess industries accounting for 39.43 percent of the total industrial consumption. Other large industrial users are the paper products industries which account for 17.20 percent of the industrial consumption and the chemical industry accounting for 15.45 percent. Residential and commercial users account for 38.49 percent and 17.78 percent, respectively, of total regional electric consumption. Of the total residential consumption, single family dwellings use over 84 percent, while retail/wholesale, office, and education services account for over half of the total commercial consumption. Historically, the

TABLE VI-1
ELECTRICITY CONSUMPTION IN THE NORTHWEST, BY SECTOR, 1980

Line No. for Sector	Sector	A Average Megawatts	B Percent of Total
	Industrial		
1.	Food	279	4.37
2.	Lumber	568	8.90
3.	Paper	1,097	17.20
4.	Chemicals	986	15.45
5.	Metals	393	6.15
6.	DSI's	2,516	39.43
7.	Other	541	8.50
8.	Total	6,380	43.73 a/
	Commercial		
9.	Retail - Wholesale	617	23.80
10.	Office	417	16.10
11.	Auto Repair	30	1.15
12.	Warehousing	100	3.86
13.	Education Services	500	19.28
14.	Health	283	10.91
15.	Public Bldg.	140	5.40
16.	Religious Services	70	2.70
17.	Hotel Bldg.	133	5.12
18.	Other	303	11.68
19.	Total	2,593	17.78 a/
	Residential Total		
20.	Single Family	4,748	84.56
21.	Multi-Family	441	7.85
22.	Mobile Home	426	7.59
23.	Total	5,615	38.49 a/

a/ Represents percent of total consumption over all sectors.

Source: Energy Load Demand Forecast, Division of Power Requirements, Bonneville Power Administration, April 1982.

region's large supply of inexpensive hydroelectricity and limited indigenous supply of gas and oil have resulted in a much greater portion of homes and businesses in the region relying on electricity for space heating than is true for the rest of the nation.

The region possesses one-third of the Nation's hydroelectric potential. Of this potential, however, most economically feasible sites have already been developed. There are 58 major hydroelectric dams in the region, of which 30 are Federally-owned. These Federal dams produce approximately half of the region's electricity. Regional electricity needs also are met by two nuclear plants (one Federally-owned and one non-Federal) and nine non-Federal coal plants. Table VI-II shows the major hydroelectric and thermal generating plants in the Northwest that are currently in operation, under construction, or authorized for construction by Congress.

Approximately three-fourths of the region's bulk high-voltage transmission system is owned and managed by BPA. The system also includes interties with the Pacific Southwest and British Columbia, allowing for exchanges and power sales.

TABLE VI-2
MAJOR NORTHWEST HYDROELECTRIC AND
THERMAL POWER PLANTS, 1981

Line No.	Plant	A Location (stream & state)	B Total Capacity (MW)
	Hydro in Operation		
1.	Bonneville	Columbia, OR-WA	585
2.	Chief Joseph	Columbia, WA	2,069
3.	John Day	Columbia, OR-WA	2,160
4.	Libby	Kootenia, MT	428
5.	McNary	Columbia, OR-WA	980
6.	The Dalles	Columbia, OR-WA	1,807
7.	Grand Coulee	Columbia, WA	6,163
8.	Rock Island	Columbia, WA	622
9.	Rocky Beach	Columbia, WA	1,213
10.	Boundry	Pend Oreille, WA	634
11.	Brounlee	Snake, ID-OR	548
	Hydro Under Construction or Authorized for Construction		
12.	Bonneville	Columbia, OR-WA	491
13.	John Day	Columbia, OR-WA	540
14.	Libby	Kootenia, MT	420
15.	McNary	Columbia, OR-WA	1,050
	Nuclear in Operation		
16.	Hanford	Hanford, WA	860
17.	Trojan	Rainier, OR	1,130
	Nuclear Under Construction Washington Public Power Supply		
18.	No. 1	Hanford, WA	1,250
19.	No. 2	Hanford, WA	1,100
20.	No. 3	Satsop, WA	1,240
	Coal in Operation Colstrip		
21.	No. 1	Colstrip, MT	330
22.	No. 2	Colstrip, MT	330
23.	Jim Bridger, No. 1, 2 and 3	Rock Springs, WY	1,500
24.	Jim Bridger No. 4	Rock Springs, WY	500
25.	Centralia No. 1 and 2	Centralia, WA	1,400
26.	Boardman	Boardman, OR	530

Source: Division of Power Resources, U.S. Department of Energy, August 1981, and Role Environmental Impact Statement, Bonneville Power Administration, December 1980, p. IV-31.

The region's electricity consumers are served by either publicly- or investor-owned utilities (IOU's). Publicly-owned utilities include public utility districts, municipalities, and cooperatives. Typically, rural areas are served by publicly-owned utilities while, with a few exceptions, urban areas are served by IOU's. Publicly-owned utilities predominate in Washington with relatively few in Oregon, Idaho, and Montana.

The publicly owned utilities are BPA's largest customer class, both in number (117) and in quantity of energy purchased. During fiscal year 1981, purchases by these customers accounted for 46 percent of the electricity marketed by BPA (BPA, 1981c). Many of these customers are totally dependent on BPA for power, while a few own their own generation which is supplemented with purchases from BPA. Consistent with the "Preference Clause" provision of the Bonneville Project Act, BPA gives priority for power from the Federal base system to these publicly-owned utilities. The Regional Act continues this preference and commits BPA to meeting the requirements of the publicly-owned utilities.

The region's eight large IOU's accounted for 9 percent of BPA's power sales in fiscal year 1981 (BPA, 1981c). These utilities either totally or jointly own generation resources. Under the Regional Act, BPA is obligated to serve the IOU's existing deficits, load growth, and the statutorily specified percentage of their residential and small farm loads. Service to their residential and small farm load is by means of the residential exchange. From IOU's wishing to participate in the exchange, BPA purchases power equal to a percentage of each utility's residential and small farm load, at the utility's average system cost. In turn, BPA sells the participating utility an equal amount of power at the same rate as that for firm sales to preference customers. The benefits from this exchange are to be passed through to the utility's residential and small farm consumers.

BPA also serves two other customer classes: Federal agencies and direct-service industrial customers (DSI's). The Federal agencies consume a very small block of BPA sales (less than 1 percent in 1979) and are served as preference customers. The 16 DSI's accounted for 33 percent of BPA's power sales in fiscal year 1981. Among them, the aluminum industry is the largest consumer.

In addition to the above customer classes, BPA sells power outside the region (primarily to the Pacific Southwest) when it is surplus to the Northwest region needs and cannot be conserved for later use. These surplus or nonfirm sales accounted for 11 percent of BPA's fiscal year 1981 power sales (BPA, 1981c).

B. Areas of Particular Concern

The purpose of this section is to identify and describe those aspects of the existing environment that are most likely to be impacted by adjustments to BPA's wholesale power rates. The discussion of these aspects of the existing environment is divided into two sections: physical and socioeconomic environment.

1. Physical Environment

a. Columbia River and Tributaries

The Columbia River and its tributaries represent one of the region's major natural resources. The close association which exists between power production and alternative uses of this resource requires that it receive careful consideration in this analysis.

(1) Water Quantity and Quality

The Columbia River and its tributaries comprise the hydrologic system that generates the majority of the power marketed by BPA. To the extent that wholesale power rate adjustments cause changes in demand for power, operations of the dams on the Columbia River drainage may be altered, potentially influencing streamflows and water quality. Changes in river operations could, in turn, affect fish and wildlife and recreational uses of the river system. In addition, the effects of power rates on the use of electricity for irrigation farming may have implications for water quantity, air and water quality, land use, and generation requirements (see Chapter V).

Generally, surface water quality in the Northwest is better than that in many parts of the country. However, significant water quality problems exist in some parts of the Columbia Basin, particularly on a seasonal basis. For example, one measure of water quality, dissolved oxygen content, has long been a problem in the lower Willamette river during summer months. Seasonal temperature increases are another water quality problem in the major Columbia River tributaries during periods of low flow. This condition can affect fish propagation; particularly that of salmonoids.

A major water quality problem directly attributable to the dams is nitrogen supersaturation. This condition occurs in the Columbia and Lower Snake Rivers when flows exceed powerhouse capacity or levels needed for power generation and water must be spilled to regulate reservoir levels. Nitrogen supersaturation presents a threat to migratory salmonoids.

Nutrients such as nitrates and phosphates from agricultural fertilizers have been a major cause of excessive aquatic algal growth in the Snake and Yakima River Basins and other areas where chemical fertilizers are used in conjunction with irrigation. This condition can be remedied with better management of water and fertilized use and if heavy flows and steep river gradients are maintained.

(2) Fish

The Columbia River and its tributaries are internationally recognized for their runs of anadromous (both salmonoid and nonsalmonoid) fish and the commercial and recreational fisheries they support. 1/ Anadromous fish require access to fresh water rivers for spawning purposes. Construction of Grand Coulee Dam on the Columbia River in 1938 limited this access for over 500 miles of the drainage above the dam. Dams also have blocked 50 percent of the Snake River to fish migration.

Impoundments of 450 miles of the Columbia downstream from Grand Coulee Dam have eliminated salmonoid spawning except in the reach from Lake Wallula to Priest Rapids Dam (the Hanford Reach). Juvenile migrant mortality also has been increased by passage through turbines and increased migration time caused by impoundments. In addition, during high flow conditions when large volumes of water are spilled, nitrogen supersaturation creates a potentially lethal condition for fish.

Other activities such as channeling, dredging, logging, and mining have negatively impacted migratory fish by destroying natural habitat and altering water quantity and quality. Pollution from industrial, domestic, mining, and agricultural sources has lowered water quality in some areas by introducing silt, pesticides, organic wastes, and toxins. This pollution has the potential to increase fish mortality.

As a result of the variety of negative effects just discussed, artificial propagation facilities, (including hatcheries and spawning channels), fish passage facilities (for both juveniles and adults), and collection and transportation programs now are employed to maintain the present population of anadromous fish (some populations are no longer at harvestable levels). Provisions in the Regional Act will ensure that adequate programs are developed for the mitigation and enhancement of fish and wildlife along the Columbia River and its tributaries. The Northwest Power Plannning Council, which was established under the Regional Act, has already requested and received fish and wildlife program recommendations from Federal and state wildlife agencies, Indian tribes, and other entities in the Pacific Northwest as required under section 4(h)(2) of the Regional Act. A draft program for protecting, mitigating, and enhancing fish and wildlife on the Columbia River and its tributaries will be completed by July 1982. The final program will be published by November 15, 1982. The program will address the relationship between the development and operation of hydroelectric projects on the Columbia River and its tributaries and protection and enhancement of fish, spawning grounds, wildlife and wildlife habitat.

In addition to the anadromous fish population, several varieties of resident fish inhabit the Columbia River Drainage. Among those of recreational importance are several species of trout (rainbow, cutthroat, lake, brook, and brown), walleye, large- and small-mouth bass, catfish, whitefish and landlocked populations of sturgeon. Most of the easily accessible trout waters are stocked with fish annually because natural production cannot keep pace with demand. While some reservoirs are good resident game fish producers, others have promoted the growth of undesirable fish (squawfish, carp, and suckers) or are poor fish producers because of a variety of factors.

b. Wildlife

There are a number of factors that affect wildlife species in the Pacific Northwest. Many animals, such as small birds, rodents, weasels, snakes, and frogs, have relatively small territories or ranges that are restricted by the variety, type and abundance of cover. Beavers, muskrats, and river otters, for example, require specific vegetation for food. On the other hand, deer, elk, larger birds, and large carnivores have relatively large territories and use a variety of vegetation types. Finally, migratory animals, such as waterfowl, are influenced by weather and the availability of water, and move between communities on a daily and seasonal basis to obtain their required conditions.

Changes or disturbances to vegetation communities have impacts on wildlife populations. The development or abandonment of agricultural land, especially irrigated cropland, has a distinct influence on wildlife diversity and numbers. Species whose habitats are enhanced by irrigation development in the Pacific Northwest include ring-necked pheasants, gray partridges, scrub jays, leopard frogs, montane voles, and yellow-bellied marmots. Those species that tend to be adversely affected by irrigation development include sharp-tailed grouse, short-horned lizards, and various animals that depend on a shrub-steppe ecosystem.

Changes or disturbances to water areas, in particular, the scarcity of wetlands and the availability of high-yield grain crops adjacent to wetlands, contribute to the increase or decrease in waterfowl habitat. The wetlands of the region are very productive for resident species as well as for transient and/or wintering waterfowl, although many of the coastal and inland wetlands in the Pacific Northwest have been altered or destroyed by development.

Changes or disturbances to riparian vegetation are associated with shoreland construction, water level fluctuations, and shoreland erosion. Species adversely affected by loss of riparian habitat include beavers, muskrats, swallows, and kingfishers. Construction and operation of the Federal Columbia River Power System (FCRPS) have modified much of the original riparian vegetation along the Columbia River and tributaries. In accordance with the Endangered Species Act (16 U.S.C. 1531 et. seq.), BPA alternatives examined in this document must avoid jeopardizing the continued existence of any endangered or threatened species or adversely modifying critical habitat. It is expected that none of the endangered or threatened species of the Northwest identified on the Endangered and Threatened Species List (50 CFR, Part 17, May 20, 1980) will be at risk as a result of an increase in BPA rates (see Chapter V for an additional discussion of endangered species).

c. Recreation

The Columbia River and tributaries provide a variety of recreational opportunities for people within and outside the Pacific Northwest including fishing, swimming, boating, and, to a limited extent, rafting. Reservoirs created by the dams have enhanced swimming and boating opportunities, but have severely limited whitewater rafting. Fluctuations in reservoir levels and streamflows can impact each of these recreational activities. Finally, the enhanced habitat for bird species as a result of irrigated grain farming has improved recreational opportunities for hunters and bird watchers.

d. Land Use

Irrigated agriculture is the primary existing land use that could be affected by adjustments to BPA's wholesale power rates. Regionwide, 8.8 million acres of farmland were irrigated in 1980 requiring diversion of 32.5 million acre-feet of water. This water originates primarily from the Columbia River and its tributaries, including the upper and central Snake River.

The Columbia Plateau is a major dryland wheat production area of the United States. In addition, major irrigation projects on the Columbia Plateau have allowed the production of row crops including sugar beets, corn, potatoes, and beans. The Snake River Plains in Idaho is another area of extensive agricultural development, much of which is irrigated. Approximately 50 percent of the row crops in the Pacific Northwest are grown in this area. Potatoes, sugar beets, and corn are the principal crops.

All of the states project increases in irrigated farmlands by the year 2000. Estimates of the increased acreage vary from 1.8 to 3.1 million acres, requiring additional water diversions of between 7.6 and 12.4 million acre-feet (Pacific Northwest River Basins Commission, 1979).

e. Air Quality

Air quality in the Pacific Northwest varies with the level and types of human activity present. The urban areas are often in violation of ambient air quality standards because of the concentration of vehicular and industrial activity. Some rural areas, especially in the Columbia Basin, experience high particulate concentrations as a result of wind blown dust. Factors contributing to this problem include agricultural operations, unpaved roads, and field and slash burning. There also are localized air quality problems caused by particular industrial operations. Direct combustion of wood for home heating is becoming an increasing source of air pollution. The states, through their approved air quality plans mandated by the Clean Air Act, are regulating activities to limit and in some cases reduce air quality degradation.

Areas within the region designated in violation of one or more Federal ambient air quality standards are listed in Table VI-3. (Note that when a final rulemaking is issued in the summer of 1982, some area classifications may be changed.)

TABLE VI-3
AIR QUALITY NON-ATTAINMENT
AREAS IN THE BPA SERVICE REGION a/

Area Line No.		A Total Suspended Particulate	B Carbon Monoxide	C Sulfur Dioxide	D Ozone
		Pollutants for Which Designation is Effective			
Idaho					
1.	Kellogg (Silver Valley)	X	X	X	
2.	Lewiston	X			
3.	Boise			X	
4.	Pocatello	X		X	
5.	Soda Springs		X		
Montana					
6.	Anaconda Area			X	
7.	Butte Area		X		
8.	Columbia Falls Area	X			
9.	Missoula	X	X		
Oregon					
10.	Portland	X	X		X
11.	Eugene-Springfield	X	X		X
12.	Salem	X	X		X
13.	Medford-Ashland	X	X		X
Washington					
14.	Seattle-Tacoma	X	X		X
15.	Port Angeles		X		
16.	Tri-Cities		X		
17.	Spokane		X	X	
18.	Longview	X			
19.	Vancouver	X			X
20.	Walla Walla		X		
21.	Yakima		X	X	
22.	Clarkston	X			
23.	Renton		X		
24.	Kent	X			

a/ This table indicates the general location of non-attainment areas. Some areas are actually quite limited in size. See Federal Register, Nov. 9, 1979 for more specific descriptions of the area boundaries.

f. Non-Renewable Resource Consumption

While much (72 percent) of the electricity produced in the Pacific Northwest is from hydroelectric facilities, which are defined as renewable resources, the remaining needs are met primarily by facilities that consume nonrenewable resources. These facilities include oil and gas fired combustion turbines, and coal and nuclear thermal plants.

Subbituminous coal and lignite reserves in the west 3/ are estimated by the U.S. Bureau of Mines, (1974), to be in excess of 178 billion short tons. Much of the low sulfur coal reserve (approximately 82 percent) is contained in the three state Northern Great Plains region of Montana, Wyoming, and North Dakota (Rieber, 1975). Approximately 31,860 tons of coal are consumed daily in the production of electricity for consumption in the Pacific Northwest. 4/ Nuclear generated electricity in the Pacific Northwest uses 64 tons of nuclear fuel each year. 5/ Projections of uranium requirements in the western world indicate that demand will exceed production capabilities within the next decade (BPA, 1977, Part 1, p. V-55).

Natural gas and oil generally are not indigenous to the region and therefore only small quantities of these resources are used for combustion turbines and other peaking units. Because of the scarcity of these fuels, electric utilities in the Pacific Northwest have not used and do not anticipate using these nonrenewable resources for baseload generation.

2. Socioeconomic Environment

BPA recognizes that the dependence of Northwest consumers on electricity varies across individual consumer classes. As a result, BPA foresees that there may be particular consumer subgroups on which the socioeconomic impact of higher electricity rates would be more severe.

a. Low Income Residential Consumers

Low income residential consumers as a group in the region consist of persons with a variety of social characteristics and living circumstances. Some fall into concise government income guidelines, while others have similar characteristics, but higher incomes. In effect, low income consumers are similar only with respect to their economic position in life.

Low income residential consumers are identified as those households whose incomes fall at or below 125 percent of the Federal government's poverty standards. The Federal standards are based on household size, the gender of head of household, and farm or non-farm residence. These standards are adjusted periodically to reflect changes in the Consumer Price Index. Typically, households with incomes which meet the 125 percent cutoff are considered eligible for various Federal programs designed to assist low-income populations and reduce poverty. For 1975, a 125 percent poverty level income of $5,500 was established for a non-farm family of four. The latest Federal guidelines (1981) place the non-farm four member household poverty level at $10,563.

As noted in the BPA 1979 Wholesale Rate Increase EIS (p. V-28), a single standard definition of the poor does not exist. Therefore, Federal poverty guidelines can be considered only as overall statistical yardsticks of poverty levels. Clearly, to the extent that individual circumstances and consumption needs vary among households, a poverty income cutoff for a given low-income household may not represent the money income required by other low-income households to maintain their economic well being (Bureau of the Census, 1978, p. 189).

The most recent published data on population levels (1979) indicate that there are approximately 2.9 million families and 8 million persons in Washington, Oregon, Idaho, and Montana. The most recent data on poverty levels in the region estimate that 10 percent of the families and approximately 13 percent of the persons have incomes of less than 125 percent of the official poverty level (Table VI-4). Nearly one-fifth (19.7 percent) of the elderly fall into this category. Of the total number of persons in the region, 9.1 percent have incomes that are less than the poverty level income. As may be expected, smaller percentages of the population have incomes that are 75 percent of poverty level.

While it may be assumed that the low-income numbers reflected in Table VI-4 are similar today, recent recession induced changes in the region's economy may have altered the numbers in each category. For example, the slump in the retail trade, housing construction, and wood products industries may have increased the number of households and elderly falling below poverty level standards, making poverty a more prevalent phenomenon.

The escalating costs of energy have had a disproportionate impact on residential consumers by income level. In 1979 for example, the affluent devoted, on the average, only 2.0 percent of their household incomes to aggregated energy costs (Table VII-5). In contrast, the poor spent nearly five times that percentage of their incomes for aggregated energy costs. The financial burden on the poor, and particularly the fixed income elderly poor, appears even heavier if these consumers utilize electricity or fuel oil for their primary heating source.

TABLE VI-4
LOW INCOME POPULATION IN THE PACIFIC NORTHWEST
(1975) a/

Line No.		A Income Less than Poverty Level Number (000)	A % of Total	B Income Less than 75% of Poverty Level Number (000)	B % of Total	C Income Less than 125% of Poverty Level Number (000)	C % of Total
1.	Families	137 (5051)	7.0 (9.0)	85 (2929)	4.3 (5.0)	196 (7394)	10.0 (13.2)
2.	Unrelated Individuals	196 (4891)	22.9 (23.7)	109 (2887)	12.7 (13.9)	277 (6859)	32.4 (33.2)
3.	Persons	674 (23,991)	9.1 (11.3)	398 (14,064)	5.4 (6.6)	968 (34,817)	13.1 (16.5)
4.	Elderly (65 & over)	84 (3,059)	11.2 (14.0)	28 (1,211)	3.7 (5.5)	148 (5,124)	19.7 (23.5)

a/ *Numbers in parenthesis indicate total U.S. poverty levels.

Source: US Department of Commerce, Bureau of Census, Money Income and Poverty Status of Families and Persons in the US and the West Region, by Divisions and States, 1978.

b. Energy Intensive Industries

BPA presently serves 15 direct-service industrial customers and has signed a contract to supply power to the Alumax corporation's aluminum plant proposed for construction near Hermiston, Oregon. The regional aluminum companies comprise the largest share of BPA's direct-service sales, purchasing more than 90 percent of this category of power. Collectively, these plants produce about one-third of the aluminum produced in the United States. The other two major production regions are the Tennessee and Ohio Valleys, with some production occurring along the Gulf Coast.

Historically, the aluminum companies located in the Northwest in order to increase this country's aluminum production capacity in response to World War II and to take advantage of the surplus hydroelectric energy available from the Columbia River Power System. This low-cost hydro power enabled the region's aluminum companies to maintain a viable competitive position despite the additional costs for transporting their product to market.

The Northwest aluminum companies provide about 13,000 relatively high paying jobs with an annual payroll of more than $1 billion.

The industry's total regional primary and secondary economic impact is estimated at $2.5 billion annually. Thus, the industry is an important element of the regional economy.

The aluminum industry is very sensitive to periods of economic recession particularly as it relates to construction, auto, and aircraft sectors of the economy. This sensitivity also translates into rapid responsiveness to periods of economic recovery. Individual corporate responses to economic downturns vary depending on the efficiency of a plant and its overall share of a company's total output. A one plant company, for instance, is not likely to curtail operations in the short run except under the most adverse market conditions. This is especially true if the long term market outlook appears favorable. Permanent shutdown would occur only if the company found it improbable that the plant would recover its fixed and variable costs over the long run.

Production sensitivity of the aluminum industry to varying economic conditions is reflected in a comparison of the proportion of electricity actually consumed by the industry for operating purposes (operation level) to: (1) the maximum amount of electricity allowed for purchase from BPA pursuant to power sales contracts (contract demand) and, (2) the amount of electricity the industry indicates it expects to consume (operating demand). For example, in 1978, a nonrecession year, the operating level of the Northwest aluminum industry was 87.7 percent of contract demand. 6/ The industries operating level declined to 78.6 percent of contract demand in 1980, a year of relatively moderate national recession. From July 1981 to March 1982, a period of relatively severe national recession, the industries operating levels averaged 79.1 percent of contract demand and only 85.1 percent of operating demand.

Companies with several plants at varied locations could more easily curtail an operation and maintain their market share and infrastructure. Thus, companies with this structure can curtail operations at their least efficient plants, depending on the expected length and magnitude of adverse market conditions. These least efficient plants become "swing plants" able to respond to swings in the national market.

BPA rate increases in recent years have reduced the competitive advantage for the aluminum industry in the Northwest. A recent study projects that the Northwest industries are approaching competitive parity with the Ohio and Tennessee Valley industries (Kristensen and Correia, 1979). Since the Northwest has several plants of pre-1946 vintage that tend to be less efficient, this approach to parity could account for some Northwest plants becoming swing plants. If Northwest electric power rates escalate at rates greater than in other primary aluminum production regions, there could, at some time in the future, be permanent plant closures. However, recent studies (Ernst, 1976; Kristensen and Correia, 1979) indicate that, with the possible exception of some of the region's oldest and least efficient plants, the aluminum industry in the Pacific Northwest will remain economically competitive, given forecast increases in the cost of electricity within the region.

FOOTNOTES

1/ Salmonoids include chinook, coho, pink, sockeye, and chum salmon; steelhead and cutthroat trout; and Dolly Vardin trout. Nonsalmonids include American shad, white sturgeon, striped bass, eulachon (smelt) and Pacific lamprey.

2/ This figure is derived from computations by the Division of Power Resources, Bonneville Power Administration, April 1982.

3/ Assumes 3540 MW of coal fired generation requiring an average of 9 tons per megawatt per day.

4/ Includes the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming.

5/ Assumes 1990 MW of nuclear generation requiring an average of 40 tons of fuel per year for a 1250 MW light water reactor.

6/ Percentages derived from computations of customer bills, Division of Rates, April 1982.

VII. Environmental Consequences

A. Introduction

This chapter forms the analytical basis from which the comparison of the consequences of the alternatives in Chapter V is drawn. As such, this chapter examines the methods and techniques employed in arriving at the projections of the consequences of an increase in BPA's wholesale rates with particular focus on the impacts on the aspects of the human environment discussed in Chapter VI.

BPA staff employed an econometric modeling process to analyze the impact of an increase in revenue level on the regional demand for electricity. The results of this analysis formed a basis for projecting the effects of rate levels on types of energy consumption and various aspects of the socioeconomic and physical environment. This econometric model will be described briefly in this chapter.

In addition to investigating the effects of rates on energy consumption in general, a considerable analytic effort was directed toward evaluating the effects of wholesale power rate increases on irrigated agriculture in the Pacific Northwest. For BPA's 1979 Wholesale Rate EIS, the agency commissioned a study of the effects of electric rate increases on irrigated agriculture. That study was updated for this statement and the results of the updated study will be summarized here. From this study's findings, conclusions can be reached as to the socioeconomic and physical environmental consequences of changes in irrigated agriculture resulting from wholesale power rate increases.

A major area of inquiry addressed by the econometric model is the effect of electricity price on the need for generation. For purposes of assessing the potential effects on the physical environment of changes in required generation, new generation requirements are assumed to be met by a combination of coal-fired and nuclear facilities. Therefore, the third section of this chapter provides information as to the environmental effects of typical coal and nuclear plants. From this information the environmental effects of constructing and operating (or avoiding operation of) generation facilities in response to changes in the demand for electricity resulting from changes in electricity price can be quantified.

The fourth section presents background information on the historic response of residential consumers to increases in energy costs, particularly electricity costs. The discussion focuses particularly on low-income residential consumers, who are found to be most impacted by increased electricity prices.

In the fifth section, this chapter will briefly describe alternative rate design concepts and their theoretical or empirical foundation. In particular, attention will be directed toward discussing the implication of alternative rate designs on consumption of electricity and associated environmental consequences. Alternative designs also may have implications on the distribution of wealth and varying impacts on particular customer classes. The extent to which these impacts would be expected to occur in association with particular design concepts will be discussed.

The final sections of this chapter address specific topics of concern in NEPA: mitigating measures, unavoidable adverse impacts, short-term uses of environmental resources versus maintenance and enhancement of long-term productivity, and irreversible or irretrievable commitments of resources.

B. Discussion of BPA's Energy Simulation Model

BPA's econometric model simulates the Pacific Northwest's supply of and demand for electricity and provides a foundation for much of the analysis in this statement. This model accommodates sensitivity analyses of effects over the period 1981-2000 of alternative wholesale energy price levels, future resource mixes, rate structures, and other factors.

The model projects the regional effects of changes in rates on electric consumption levels among residential, commercial, and industrial users. It also forecasts the conversions by consumers to other types of energy (fossil fuels) in response to price and availability of electric power. Given a mix of available current and future sources of electricity, the model develops a schedule for yearly additions of hydroelectric units, thermal units and conservation. Thus, it provides a basis for evaluating environmental impacts during the forecast period.

The current BPA supply model evolved from the model developed in 1977 for use in BPA's Role EIS. The model has been modified on an ongoing basis to represent new developments in areas such as policy decisions, the Regional Act, availability of resources, and planning assumptions. The demand side of the model was developed from the Oak Ridge National Laboratories (ORNL) Residential and Commercial and the Northwest Energy Policy Project (NEPP) Industrial demand models. An overview of the energy simulation model, the types of output generated, and the assumptions made for the analysis in this statement is presented in this chapter. A detailed discussion of the model's logic, components, assumptions, and inputs is included in the technical support paper accompanying this statement.

1. Model Overview

BPA's Energy Simulation Model consists of two distinct elements, i.e., supply and demand. The model is a manually interactive supply/demand model that generates load projections given a set of generated prices. The supply/pricing portion of the model determines wholesale and retail rates based on the cost of resources needed to meet a set of exogenously determined loads. The retail prices for each of 20 years for the public and private utility residential, commercial, and industrial sectors become inputs to the demand side of the model. The demand models use the matrix of prices to generate expected demand for electricity over the same 20 year period. These new demands are entered into the supply/pricing portion of the model and new prices are generated. The new price matrix is then entered into the demand side to generate a new set of loads. This manual iteration between the demand and supply portions of the model continues until a convergence is reached (i.e., loads and prices arrive at a point of equilibrium). The final solution is the expected loads and prices for each sector and the resulting resource mix for each year during the 20 year forecast period.

a. Supply/Pricing Model

(1) Inputs

The amount of load that must be met by the supply/pricing model is determined by a combination of direct inputs of load data and load data generated by the demand models. The direct inputs include fixed contractual loads (excluding the DSI), exports, and Federal agency loads for each of the 20 years in the forecast period. The demand models provide estimates of residential, commercial, and industrial loads served by both public and private utilities.

The model uses both historic and future resources to meet defined load requirements. The composite generating capacity of all regional hydro units under average and critical water conditions is specified. A simulation of historic streamflows is utilized to estimate the secondary energy from the hydro system and allocates it on a priority basis across potential markets. Other resources available to the model include existing and future thermal, capacity/energy exchange agreements, contracted energy from the Canadian Storage Power Exchange (CSPE), and purchase power. The supply/pricing model includes investment, operating, and contract costs of the various energy resources.

Costs of currently budgeted BPA conservation programs are input for FY 1982 through FY 1987. (Conservation expected to result from these programs is input to the demand side of the model.) No conservation costs after FY 1987 are assumed, since direct BPA involvement in programmatic conservation beyond the current planning horizon is difficult to forecast.

BPA transmission costs were input based on recent analysis by BPA staff. Public and private utility transmission costs and costs of distribution to customer groups were derived from annual financial statements and information provided by utility staff.

(2) Operation

This supply/pricing model first enters embedded resources to meet BPA's load requirements in a given year. After making proper adjustments for various contractual arrangements which provide resources to the utilities, the model checks the resource/load balance for public and private utilities. Any deficits for either sector are assumed to be met by purchases from BPA, addition of future available hydro or thermal resources, and purchase power, in that order.

The determination of energy costs begins with a calculation of all capital, operating and contract costs for all resources used to meet the load requirement. The energy costs are adjusted for revenues from secondary hydro energy. The model also assures that the resource pools are matched to the load pools to determine BPA's non-transmission cost of providing energy to the different load pools. This calculation for each year is treated consistent with the Regional Act, which provides for a value of reserves credit to DSI customers and the residential exchange power by participating utilities. Federal transmission costs are then added to determine BPA's rates.

The supply/pricing portion of the model then estimates retail rates of private and public utilities based on their wholesale cost of power from BPA, utility generation and transmission costs, the private residential exchange, and utility costs of distributing power to residential, commercial, and industrial customers.

(3) Results

The supply/pricing model generates forecast data for each year in the 20 year forecast period by customer class, resource type (hydro, thermal, purchase power, etc.), and energy class (firm or secondary). These data include price per kilowatthour, total dollar cost, and total kilowatthours of energy. The model accommodates analyses such as breakdowns of costs between generation and transmission, comparisons of critical and secondary resources to firm and secondary loads, and forecasts of resource mixes necessary to meet aggregate loads.

b. Demand

Demand, as used in the context of this discussion, refers to the term in standard economic reference and not in the context in which the term is used in the electrical energy industry. The demand portion of the model simulates changes in the quantity of electricity consumed in response to changes in the price of electricity, the price of alternate fuels, ownership and use of appliances, housing, population, and income characteristics.

The amount of electricity consumed is a function of the elasticity relationships that the model simulates. Price elasticity is measured by the percentage change in quantity demanded of a good or service divided by the percentage change in price. For example, if electric rates increase by 30 percent but the quantity of electricity demanded decreases by only 5 percent, then price elasticity is said to be relatively inelastic. Cross-elasticity of demand measures the effect of changes in the price of substitute fuels (oil, gas, etc.) on the quantity of electricity consumed. Income elasticity reflects the impacts of income changes on electrical consumption.

The demand side of the model uses three previously developed models, the Oak Ridge National Laboratory (ORNL) residential and commercial models and the Northwest Energy Policy Project (NEPP) industrial model, and direct input information on BPA conservation programs and DSI operating and contract demands.

(1) Inputs

The residential model contains information on energy use for eight end-use categories (space heating, air conditioning, water heating, cooking, refrigeration, freezing, lighting, and other) for the 1979 base year. This information is input for four fuel categories (electricity, natural gas, fuel oil, and other) and for three housing types (single family, multiple family, and mobile homes). Base year values also include behavioral variables used in economic relationships and parameter estimates of technical relationships (i.e., appliance efficiency). In addition, projected housing stocks, fuel prices, and per capita income are input for each year during the forecast period. Cumulative amounts of conservation resulting from BPA conservation programs which are currently budgeted for FY 1982 through FY 1987 are also input through the year 2000. As stated previously (see Section VII.B.1.a.(1)), no additional BPA conservation programs after FY 1987 were assumed due to the difficulty in forecasting the extent of BPA's future involvement in these programs.

The commercial model inputs are also a combination of base year data and forecast data to the year 2000. Data on floorspace in 1924 and yearly additions to floorspace through 1970 for ten building types are input. 1979 base year data on end-use by fuel type, energy use per square foot, fuel prices, and capital costs of heating, ventilating and air-conditioning equipment are included, along with historic and forecast data for fuel prices and real per capita disposable income. As in the residential model, anticipated savings from the currently budgeted BPA conservation programs are reflected for 1982 through 2000.

Forecasts from the industrial model are based on historic and projected energy prices, employment, value added, and personal income. BPA's industrial customer demands for energy during the forecast period constitute a separate input.

(2) Operation

The residential demand model uses measures of short run and long run responses to specified prices of alternate fuels, technical trends (e.g., appliance efficiency), housing characteristics, and income data. This information, in conjunction with prices for electricity obtained from the supply/pricing model, determine yearly electrical demands. An adjustment is made to reflect the effects of BPA programmatic conservation, while price-induced conservation is considered to be part of any decrease in electric consumption in response to price.

The commercial model endogenously projects four characteristics of building fuel use: floorspace (by building type and vintage), floorspace saturations (by fuel type and end-use), equipment utilization, and energy use per square foot. These projections for each year are multiplied together to forecast commercial energy use, using specified projections for non-electrical energy prices and electricity prices input from the supply pricing model. Appropriate allowances are made for BPA conservation programs.

The demand for energy within the industrial sector is forecast using data for projected electrical demand among DSI customers and the NEPP industrial model. The NEPP econometric model estimates, for a given year, total energy demand among non-DSI customers based on estimates for energy prices (electricity prices obtained from the supply/pricing model), employment, value added, and personal income, and the previous year's demand. The model then distributes the total demand for energy among fuel types, taking into account limitations in fuel switching as a result of existing stocks of capital goods. The projected consumption for electricity among DSI industrial customers is based on BPA-DSI contract information.

(3) Results

The residential demand model produces forecasts for energy use by fuel type, by type of dwelling, and by end-use. Forecasts for energy consumption in the commercial sector are by fuel type, building type, and end-use. The industrial model provides forecast energy demand by fuel type.

2. EIS Alternatives

The BPA Energy Simulation Model was used to analyze eight alternatives for presentation in the EIS. The purpose of the analysis was to compare the relative impacts of alternate wholesale electric prices during the period 1980-2000. Because electrical prices in each of the alternatives are exogenously determined, the function of the supply/pricing model to generate prices which achieve an economic load/resource equilibrium is superceded. The function of the supply/price model, for the purpose of analyzing these alternatives, was altered to provide the necessary resource mix to meet electrical demands in response to these exogenously defined prices for electricity. The results of these analyses reflect alternate total generation and resource mixes, which correspond with each alternative.

This EIS examines the impacts of rate increases through two types of study alternatives. A series of four 1982 alternatives, designed to evaluate the impacts of various possible future rates, assume historic rates for FY 1980 through 1982 and alternative future rates from FY 1983 through FY 2000. Four cumulative alternatives, which focus on the impacts of both historic and future rates, assume alternative series of rates for both the historic (1980-1982) and future (1982-2000) periods.

The 1982 alternatives all assume historic BPA wholesale per kilowatthour rates for FY 1980, FY 1981, and FY 1982 of 7.4 mills, 7.4 mills, and 11.4 mills, respectively. The "1982 No Action" alternative assumes that the current price of 11.4 mills remains unchanged through FY 2000. The three remaining 1982 alternatives analyze the impacts of alternative one-time increases effective October 1, 1982, through the end of the forecast period (FY 2000). In the "1982 Proposal" alternative, a rate of 19.6 mills is input for FY 1983 through FY 2000 to examine the long-term effects of the proposed October 1, 1982, rate increase. The "1982 LRIC" alternative uses the current LRIC of electricity, 54.0 mills, from FY 1983 through FY 2000. The final 1982 alternative, the "1982 phase in LRIC" alternative uses a rate of 26.4 mills to reflect the impacts of partial incorporation of LRIC based pricing beginning in FY 1983.

The first cumulative alternative, the "Cumulative No Action" alternative, was used to study impacts which would have resulted from no rate increases after FY 1979. The price of 3.5 mills which was in effect during FY 1979 is assumed for the entire period FY 1980 through FY 2000. The "Cumulative Original LRIC" alternative uses a 1983 LRIC price of 54.0 mills for the entire twenty year period. In the "Cumulative Proposal" alternative, historic prices of 7.4 mills, 7.4 mills, and 11.4 mills are input for FY 1980, FY 1981, and FY 1982, respectively. For this alternative, projected proposed rates of 19.5 mills for FY 1983 and 24.0 mills for FY 1984 through FY 2000 are assumed. The final scenario, the "Cumulative phase in LRIC" alternative, simulates the effects of achieving a full current LRIC price in FY 1987 through a series of five annual graduated increases, beginning in FY 1983. This alternative assumes historic prices for FY 1980, FY 1981, and FY 1982 of 7.4 mills, 7.4 mills, and 11.4 mills, respectively, and graduated LRIC prices of 26.4 mills in FY 1983, 33.3 mills in FY 1984, 40.2 mills in FY 1985, 47. 1 mills in FY 1986, and, finally, 54.0 mills for FY 1987 through FY 2000.

C. Irrigated Agriculture Study

As an integral part of BPA's evaluation of its rate proposal and alternatives, BPA contracted for a re-examination and updated study of the potential impacts of electricity rates on irrigated agriculture in the Pacific Northwest. This study, completed under the direction of Dr. Norman K. Whittlesey, Professor of Agricultural Economics at Washington State University, was completed in January 1982. In 1978, BPA contracted with a team led by Dr. Whittlesey to examine the effects of increasing electricity prices on irrigated agriculture for BPA's analysis of its 1979 rate increase (Whittlesey, 1978, p. 56; and Supplement, 1979). The 1982 study was to update the results of the 1978 study and to reflect changes that have occurred in the intervening period. Both the 1978 and 1982 studies form the foundation for BPA's analysis of the effects of electricity price on the region's irrigated agriculture as discussed in Chapter V.

The primary objective of the Whittlesey study was to estimate changes in the quantity of electricity demanded by irrigated agriculture for pumping water in response to increases in the cost of electricity. Whittlesey developed a computer model that incorporates estimates of price elasticities of demand by irrigated agriculture in subregions of the Pacific Northwest to project responses to increasing electricity price over time. The 1982 Whittlesey study focused on: (1) changes in existing irrigated acreage; (2) changes in future expected irrigated acreage; (3) average irrigated agriculture income impacts; and (4) alterations of crop patterns. Additionally, projections of new irrigation development were made, apart from the formal modeling effort, to consider irrigated land expansion resulting from increases in demand (see Table V-8). The following summarizes the methodology and general findings of the Whittlesey study. The specific projections with respect to the 1982 and cumulative proposed rates and alternatives are presented in Chapter V. Copies of the Whittlesey study are available from BPA's Public Involvement Coordinator.

Figure VII-1 shows the major subregions of the Pacific Northwest examined in the study. Of this area, 9 million acres is irrigated land. Idaho has the largest share of total irrigated land with 4 million acres; Oregon and Washington follow with approximately 2.4 million acres and 2.0 million acres, respectively. The Columbia River Basin also includes smaller amounts of irrigated land in Montana, Wyoming, Utah, and Nevada. Table VII-1 shows total irrigated acreage, by state, in the Pacific Northwest.

TABLE VII-1
IRRIGATED LANDS IN THE PACIFIC NORTHWEST
1980

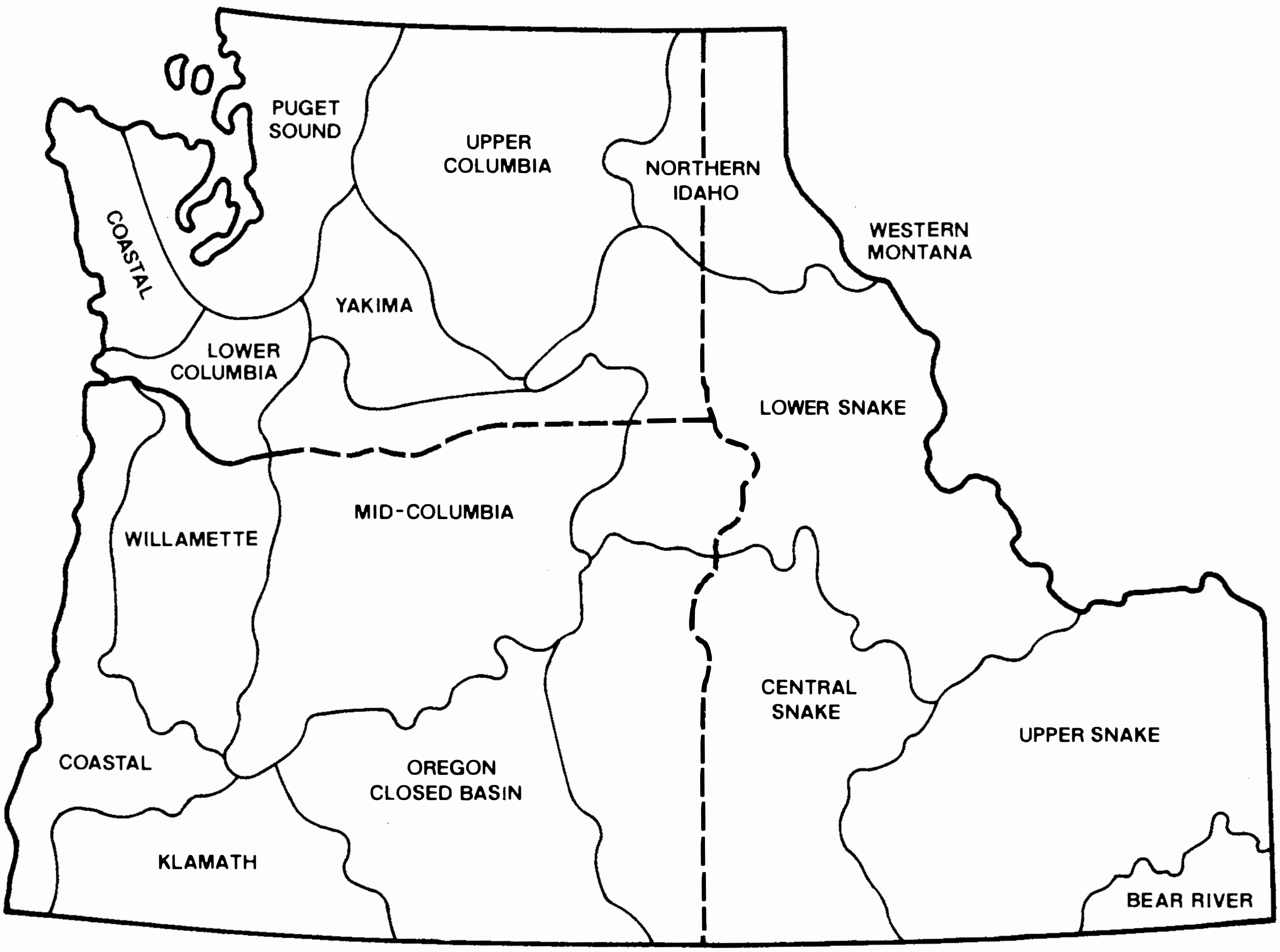
Line No.	State	Total Irrigated Acres
1.	Idaho	4,049,900
2.	Oregon	2,337,900
3.	Washington	1,951,600
4.	Montana	460,100
5.	Wyoming	94,100
6.	Nevada	70,400
7.	Utah	5,600
		8,969,600

Source: Whittlesey, January 1982, p. 4.

The irrigated lands considered in the Whittlesey study are served by both publicly owned and investor-owned utilities. The study did not include land that is irrigated under subsidized programs such as that of the Bureau of Reclamation. Some of the publicly owned and investor-owned utilities purchase power from BPA for resale to their irrigation customers. Nearly four percent of the power BPA sells to preference customers is in turn sold to farmers for irrigation purposes. 1/ The proportion of each utility's power that is from BPA and other resources varies; thus the prices for electricity charged to irrigators by the utilities vary. For example, the average retail price paid for electricity in 1980 for irrigation ranged from 40 mills per kilowatthour in the Bear River subregion of southern Idaho to 14 mills per kilowatthour in the upper Columbia subregion of Washington. This is a variation of nearly 300 percent. On the average, regionwide irrigation system power costs were approximately 22 mills per kilowatthour in 1980.

Even with this variation in power costs for irrigationm farmers in the Pacific Northwest have traditionally experienced low electricity prices and, as a result, have invested heavily in electrically powered irrigation systems. However, significant increases in average retail costs occurred between 1979 and 1981 due in large part to the implementation by BPA of an 88 percent increase in wholesale firm power rates on December 20, 1979. A further BPA wholesale rate increase of 59 percent for priority firm customers was implemented on July 1, 1981. Under BPA's proposed October 1, 1982, rate increase, the priority firm power rate would increase by an

FIGURE VII-1
Major Agricultural Subregions of the Pacific Northwest



additional 73 percent. The percent increase in retail rates required to recover these increases in wholesale power costs are substantially lower than the wholesale increases since wholesale power costs represent but a portion of total utility costs. Nevertheless, increases in retail rates necessary to recover increases of this magnitude in wholesale power costs may reduce the region's historic competitive advantage for irrigated agriculture. This effect may be partially offset for some farmers by the residential and small farm exchange provisions of the Regional Act. These provisions are designed to reduce disparities between the rates which public and private utilities charge their residential and small farm consumers. Whittlesy (1982, p. 20) predicts that the real cost of power to irrigated agriculture will remain relatively stable after 1982.

The Whittlesey research team employed a linear programming model to assess the response of irrigated agriculture to increases in real electricity prices. Both short run (to 1990) and long run (to 2000) responses were analyzed. Data on farm operation costs, irrigation systems, crop mixes, crop prices, and other factors were held constant to isolate the potential responses to increases in real electricity prices. Test farms consisted of 60 "typical" farms in the region; 16 in Oregon, 24 in Washington and northern Idaho, 17 in southern Idaho, and 3 in Montana. The number and distribution of crops used in the programming model to represent typical farms reflected the actual distribution of crops within a subregion, the compatibility of crops with irrigation systems, and the agronomic requirements of crop rotation. Usually four to six crops were used for a typical farm and the acreage within a given subregion.

The model assumes that farmers adjust to changes in prices of production inputs in a manner that maximizes profits. It was assumed that, in the short run, irrigation systems could not be changed, but improvements in irrigation management, higher pump efficiencies and changes in crop acreage or mix would occur. For instance, the model assumed efficiencies in water application would improve 5 percent for side-roll, hand-move, and solid set irrigation systems (from 65 percent to 70 percent), and pumping plant efficiencies would increase 10 percent for each system including center pivot (from 55 percent to 65 percent).

In assessing the long run (to 2000) response of irrigated agriculture to increases in retail electricity prices, Whittlesey assumed increases of 22 mills, 44 mills and 88 mills per kilowatthour over the current average retail rate for electricity. These price increases were incorporated into the analysis in real 1981 dollars and reflect retail increases of 100 percent, 200 percent, and 400 percent, respectively.

In the long run, potential adjustments to rising electricity prices may include the short run measures identified above as well as changes to low pressure irrigation technology, changes in overall irrigation systems (e.g., switching from less efficient side-roll systems to center pivot systems) and possible reversion to dryland crop production, thereby reducing irrigated acreage. There also is the possiblity that in areas where dryland farming is not feasible, agricultural production could cease.

In general, the Whittlesey study concluded that there would be no changes in the short run in irrigated acreage as a result of BPA's proposed rate increase. However, extrapolating from Whittlesey's data, BPA estimates that long run incremental cost pricing would be expected to reduce irrigated acreage by nearly 380,000 acres in the short run. This extrapolation is based on the assumption that 50 percent of the long run adjustment indicated in Whittlesey's data would occur within a short run timeframe (see Table V-7, lines 3 and 6). The major short run responses to price increases would consist of managerial improvements resulting in higher efficiencies in the application of water and operation of electrical pumps.

In the long run, Whittlesey finds that an addition of 22 mills per kilowatthour (100 percent above 1982 price levels) would remove approximately 180,000 acres of land from irrigated production in the Pacific Northwest (a long run price elasticity of -.35). The addition of 44 mills and 88 mills per kilowatthour in the long run (respective price increases and estimated elasticities of 200 percent and -.50, and 400 percent and -1.49) would further reduce irrigated lands by about 800,000 acres and 500,000 acres, respectively, for a total of 1,300,000 acres. The tabular data contained in Chapter V regarding irrigated acreage changes under BPA revenue alternatives were adapted by BPA staff from these figures through means of linear interpolation.

Whittlesey found that irrigated acreage in Oregon would be particularly unresponsive over the long run to changes in electricity prices. Fewer pump lift systems overall appear to provide Oregon with a relatively stable agricultural base in response to electricity price changes. Only in the Mid-Columbia subregion, where pump lifts are greater than the average in Oregon, would there be a response to changes in electricity prices.

In examining the impacts of electricity price on irrigated agriculture income, Whittlesey found again that, in the short run, changes in average income would be expected to be negligible. As indicated in Chapter V, price increases in the long run would result in significantly larger changes in farm income. Whittlesey notes that while most farmers would make short and long run operational adjustments in response to rising electricity prices, these adjustments would be critical only for "marginal farms." These farms are most vulnerable to higher power costs as they typically have smaller profit margins, higher pump lifts and are most dependent on sprinkler irrigation technology. Consequently, the competitive advantage and ultimate survival of marginal farms is very dependent on future efficiency and crop acreage adjustments.

As noted earlier, Whittlesey finds that electricity costs to irrigated agriculture in the Pacific Northwest are expected to be relatively constant in real terms into the forseeable future. As a result, additions of new irrigation development will be determined primarily by factors other than electricity prices. These will include economic and policy factors such as capital subsidies, tax programs, land grants, special repayment schedules, and crop support prices, as well as better management and improved technology. However, Whittlesey concludes that, in the absence of some type of subsidy, no new lands in the region can be profitably developed in the short run because of present economic constraints. Over the long run, it is possible that lands will be developed for irrigated production as a result of improvements in the region's economic climate. This variation in the feasibility of future irrigation development caused Whittlesey to distinguish between "most likely" and "less likely" future irrigation as shown in Table V-8. While no specific time table was projected for the most likely development, it is expected that this land will be brought into production in a relatively linear fashion.

Because farmers have latitude to alter their production techniques and patterns, it is probable that all of the possible short and long run adjustments considered in the Whittlesey study are presently being implemented by Pacific Northwest farmers. For example, some farmers are currently adopting low pressure irrigation systems while others are continually adjusting crop patterns and improving management practices in reaction to higher electricity costs. As a result, there may be a gradual phasing-in of adjustment measures to any given BPA price increase from the short to the long run. In addition, other input costs and market conditions are significant factors that affect the future of regional irrigated agriculture.

D. Environmental Consequences of Conventional Coal and Nuclear Generation Facilities

A major consequence of an increase in the price of electricity is a decrease in the growth of consumption of electricity. Over time, a slower rate of growth in the demand for electricity would either postpone or eliminate the need for new generation facilities. BPA's Energy Simulation Model projects future regional demand for electricity in response to alternative electricity prices as well as a mix of resources adequate to meet forecast demand. While future regional generation needs will be met from a wide variety of resources including conservation and renewables, for purposes of quantifying potential worst case environmental effects of alternatives, it was assumed this need would be met by conventional coal-fired and nuclear facilities. The following discussion presents information on the effects of typical coal-fired and nuclear facilities which was used to form the basis for the analysis of the environmental effects of changes in generation requirements presented in Chapter V.

TABLE VII-2, STEP 1

Open Pit Uranium Mining

ENERGY SYSTEM:

SIZE
- typical mine size of 5.28×10^5 tons/year supports 4.8 model LWRs
- 4,600 tons produce 10^{12} Btu/year
- 0.8 capacity factor
- recovery efficiency 80%
- 20 year lifetime

DESCRIPTION
- Open pit mining accounted for about 48% of ore production during 1976. It is done when the ore body lies under relatively friable material at depths up to several hundred feet.

COMPONENTS
- large open excavation
- large piles of earth and rock overburden
- network of operating roads and yards
- flow of mine water pumped into local surface drainage or holding ponds
- shops
- warehouses
- office and changehouse structure
- assortment of heavy earth moving equipment
- blasting
- drill rigs 3 years lifetime

ENVIRONMENTAL CONCERNS
- air emissions from heavy earth moving equipment and blasting
- disposal of mine drainage water
- barren rock and earth overburden containing uranium and its daughter products
- uranium bearing dusts and radon and its daughter emissions from mining operations
- dissolved and suspended uranium and its daughter products in mine drainage water
- reclamation of land
- aesthetic considerations
- trace metal contaminants
- mine tailings disposition
- accident risks - flooding, fire and washout, blasting, heavy equipment accidents and pit wall failure

RESOURCES USED:
(Per 10^{12} Btu Produced)

ENERGY	
electricity	11.5 MWh(a)
diesel fuel, oil, and grease	12,700 gallons(e)

LAND	Acres(a)
temporarily committed	2.5
undisturbed area	1.8
disturbed area	0.7
permanently committed	0.1
total	2.6

WATER	Acre-Ft.(a)
discharged to ground	17.3

MATERIALS	Tons(1)(d)
concrete	0.14
total steel & castings	32.40
copper, brass & bronze	0.40
aluminum & castings	0.19
manganese	0.15
chromium	0.07
nickel	0.002
cast iron	1.35

COSTS	Dollars (1978)(4)(d)
construction	
manpower	110,000
materials	22,000
equipment	66,000
other construction	66,000
(land rights)	(66,000)
(escalation during construction)	(33,000)
(interest during construction)	(99,000)
(working capital)	(55,000)
total	264,000
operation & maintenance	198,000

PERSONNEL	Workers(d)
construction (4 years)	1.0
operation	3.5

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons
particulates	0.27(e)
SO_2	0.43(a)
NO_x	0.25(a)
hydrocarbons	0.02(a)
CO	0.001(a)

WATER POLLUTANTS	Tons
suspended solids	NA
dissolved solids	NA
trace elements	NA

SOLID WASTE	Tons
overburden moved	1.4×10^5 (a)

RADIATION	Curies
Air	
radon and radon daughters	negligible(2) (NRC presently reconsidering emission rate)

ENERGY PRODUCT	Tons(3)
uranium ore	4,600(a)

(1) Selected materials and equipment items.
(2) Negligible because it is rapidly diluted in the atmosphere and has a very short half-life, but some of the daughter elements are long-lived.
(3) The amount of ore mined is adjusted to account for a 9% loss of material in the milling stage because the mill requires a total throughput of 4,200 tons of ore at 0.2% U_3O_8 per 10^{12} Btu output.
(4) Items in parentheses are not included in total.

SOURCE: (a) U.S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle (Wash. 1248), 1974.
(b) University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
(c) U.S. Department of Energy, Environmental Development Plan - Uranium Mining, Milling, and Conversion, DOE/EDP-0058, 1979.
(d) Bechtel Corporation, Energy Supply Planning Model, 1978.
(e) U.S. Environmental Protection Agency, Energy from the West - Energy Resource Development Systems Report, Volume IV: Uranium, EPA-600/7-79-060d, 1979.

TABLE VII-2 STEP 2

Uranium Milling

ENERGY SYSTEM:

SIZE
- typical mill size of 1,060 tons/year of Uranium concentrate (U_3O_8) support 5.3 model Light Water Reactors (LWRs)
- 12.31 tons yellowcake (75% U_3O_8) produce 10^{12} Btu output
- 0.8 capacity factor
- recovery efficiency 91%
- 20 year lifetime

DESCRIPTION
- Milling operations extract uranium from the ore and concentrate it into a semi-refined product called "yellowcake", using both mechanical and chemical processes.

COMPONENTS
- ore storage and blending area
- crushing and sampling building
- mill building containing grinding equipment
- acid or alkaline leach tanks (sulfuric acid or sodium carbonate or bicarbonate are typical)
- solvent extraction building
- thickeners
- tailings retention system of about 250 acres
- sewage treatment system
- several ancillary buildings for office and maintenance purposes

ENVIRONMENTAL CONCERNS
- emissions of sulfuric acid fumes, kerosene vapors, and dusts from uranium mill processes
- low level radiological pollutant releases, including uranium and uranium daughter products from milling operations
- liquid and solid chemical and radiological waste discharges to retention ponds
- heat dissipation may cause dense fogging conditions near site
- water availability
- toxic metals - impacts on ground-water quality
- long-term management of uranium mill tailings piles
- accident risks - fires, heavy equipment, tailings pond dike failure
- radon releases

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons[a]
uranium ore	4,600

ENERGY	
electricity	113 MWh[a]
natural gas	2.9×10^6 scf[a]

LAND	Acres[a]
temporarily committed	0.02
undisturbed area	0.01
disturbed area	0.01
permanently committed (limited use)	0.10
total	0.12

WATER	Acre-Ft.[a]
process water	8.3

MATERIALS (1)	Tons[e]
concrete	95.20
total steel & castings	32.80
copper, brass & bronze	0.32
aluminum & castings	0.63
manganese	0.15
chromium	0.03
nickel	0.01
cast iron	0.47
pumps & drivers (1000 HP)	0.05

COSTS	Dollars (1978)[e]
construction (3)	
manpower	50,000
materials	20,000
equipment	50,000
other construction	30,000
(land rights)	(200)
(escalation during construction)	(6,000)
(interest during construction)	(9,000)
total	150,000
operation & maintenance	120,000

PERSONNEL	Workers[e]
construction (2.3 years)	0.7
operation	2.7

RESIDUALS AND PRODUCTS. (2)
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons
particulates	2.30[c]
SO_2	1.70[a]
NO_x (40% from natural gas use)	0.73[a]
hydrocarbons	0.06[a]
CO	0.01[a]

WATER POLLUTANTS	Tons[a]
tailings solutions	11,000
other pollutants	NA

SOLID WASTE	Tons[a]
tailings	4,170

RADIATION

Air	Curies
Rn-222	61.5 (NRC presently reconsidering emission rate)[d]
Ra-226	8.3×10^{-4}[a]
Th-230	8.3×10^{-4}[a]
U-natural	1.2×10^{-3}[a]

WATER	Curies[a]
U & daughters	8.3×10^{-2}

SOLID WASTE	Curies[a]
U & daughters (buried)	25.0

HEAT	Btu's[a]
heat discharged to air	2.9×10^9

ENERGY PRODUCT	Tons[a]
yellowcake (75% U_3O_8)	11.2
U_3O_8 (purified)	8.4

(1) Selected materials and equipment items.
(2) Residuals are a function of the leaching process; sulfuric acid leaching is assumed.
(3) Terms in parentheses are not included in total.

SOURCES:
(a) U.S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle (Wash. 1248), 1974.
(b) U.S. Department of Energy, Environmental Development Plan - Uranium Mining, Milling and Conversion, DOE/EDP-0058, 1979.
(c) U.S. Environmental Protection Agency, Energy from the West - Energy Resource Development Systems Report, Volume IV: Uranium, EPA-600/7-79-060d, 1979.
(d) U.S. Nuclear Regulatory Commission, Draft Generic Environmental Impact Statement on Uranium Milling, NUREG-0511, 1979.
(e) Bechtel Corporation, Energy Supply Planning Model, 1978.

TABLE VII-2, STEP 3

Uranium Hexafluoride Conversion

ENERGY SYSTEM:

SIZE
- 5,500 tons/year
- supports 27.5 model Light Water Reactors (LWRs)
- 8.4 tons produce 10^{12} Btu output
- 0.8 capacity factor
- recovery efficiency 100%
- 20 year lifetime

DESCRIPTION
- Uranium hexafluoride (UF_6) conversion converts the U_3O_8 (yellowcake) concentrate to a volatile UF_6 compound for enrichment by the gaseous diffusion process. UF_6 conversion can be done by either the dry or wet hydrofluor process.

COMPONENTS

Dry Hydrofluor Process
- pre-process handling, weighing, sampling and storage
- reduction-roasting of Uranium concentrate (U_3O_8) with cracked ammonia (N_2 & H_2) to form UO_2
- hydrofluorination - F_2 reacted with UF_4 to form UF_6 crude product
- cold trap - removal of molybdenum and vanadium impurities
- distillation - fractional distillation purifies the UF_6 product
- waste ponds

Wet Chemical Solvent Extraction Process
- pre-process handling, weighing, sampling and storage
- digestion in hot nitric acid
- countercurrent solvent extraction with TBP in hexane
- reextraction of uranium as uranyl nitrate solution
- calcination to UO_3
- reduction - UO_3 reduced to UO_2 with cracked amonia
- hydrofluorination, fluorination, and cold trap same as dry process
- waste ponds

ENVIRONMENTAL CONCERNS
- emissions of off-gases from UF_6 preparation, e.g., fluorides and oxides of nitrogen
- liquid waste from the two waste streams which require holding for future reprocessing or burial
- solid chemical effluents from hydrofluor process
- release of radium to nearby river and disposal of radioactive sludge
- heat dissipation from UF_6 production
- water availability
- accident risks - fires in solvent extraction, failure or rupture of UF_6 cylinder, raffinate pond failure, uranium nitrate hexahydrate evaporator failure, and HF release from a storage tank

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons(a)
yellowcake at 75% U_3O_8	11.2
U_3O_8 (purified)	8.4
ENERGY	
electricity	71 MWh(a)
natural gas	0.83×10^6 scf(a)
LAND	Acres(a)
temporarily committed	0.10
undisturbed area	0.09
disturbed area	0.01
permanently committed	0.001
total	0.10
WATER	Acre Ft.(a)
discharged to air	0.42
discharged to water bodies	2.94
total	3.36
MATERIALS (1)	Tons(c)
concrete	395.00
total steel & castings	12.50
copper, brass & bronze	0.19
aluminum & castings	0.06
manganese	0.06
chromium	0.06
nickel	0.01
cast iron	0.15
pumps & drivers (1000 HP)	0.01
heat exchangers (1000 ft^2 surface)	0.05
non-nuclear pressure vessel	0.33
COSTS	Dollars (1978)(c)
construction (2)	
manpower	20,000
materials	9,000
equipment	20,000
other construction	10,000
(land rights)	(300)
(escalation during construction)	(5,000)
(interest during construction)	(10,000)
(working capital)	(10,000)
total	59,000
operation & maintenance	24,000
PERSONNEL	Workers(c)
construction (3 years)	0.3
operation	0.4

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons(a)
SO_2	1.30
NO_x	0.46
hydrocarbons	0.04
CO	0.01
F^-	0.005
WATER POLLUTANTS	Tons(a)
F^-	1.20
SO_4^-	0.21
NO_3^-	0.01
Cl^-	0.01
Na^+	0.16
NH_3^+	0.07
Fe	0.002
SOLID WASTE	Tons(a)
solid chemical effluents (non-volatile ash containing Fe, Ca, Mg, Cu, F^-)	1.8
RADIATION	
Air	Curies(a)
uranium	6.2×10^{-6}
radon and daughters	NA
WATER	Curies(a)
Ra-226	1.4×10^{-4}
Th-230	6.3×10^{-5}
uranium	1.8×10^{-3}
SOLID WASTE	Curies(a)
low and intermediate level (buried)	3.6×10^{-2}
HEAT	Btus
heat discharged to air	0.83×10^9
ENERGY PRODUCT	Tons(a)
UF_6	8.4

(1) Selected materials and equipment items.
(2) Costs in parentheses are not included in total.

SOURCES: (a) U. S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle (Wash. 1248), 1974.
(b) U.S. Department of Energy, Environmental Development Plan - Uranium Mining, Milling, and Conversion, DOE/EDP-0058, 1979.
(c) Bechtel Corporation, Energy Supply Planning Model, 1978.

TABLE VII-2 STEP 4

Uranium Enrichment Gaseous Diffusion

ENERGY SYSTEM:

SIZE
- 12,000 tons/year
- supports 91 model Light Water Reactors (LWRs)
- 8.4 tons UF_6 produce 10^{12} Btu output
- 0.8 capacity factor
- recovery efficiency 65.4%
- 20 year lifetime

DESCRIPTION
- Gaseous diffusion enrichment is accomplished by passing the volatile Uranium hexafluoride (UF_6) compound through porous barriers and cascades to produce the product material 4 percent ^{235}U.

COMPONENTS
- buildings - process, auxiliaries and support, warehouse and storage
- roadways and parking lots
- storage yards - UF_6
- electric switchyards
- steam plant
- recirculation water system
- fire protection water system
- water (chemical treatment) plant
- nitrogen plant
- dry air plant
- tails storage - UF_6
- setting neutralization ponds
- waste burial grounds
- fluorine production

ENVIRONMENTAL CONCERNS
- recycle fission products
- air emissions from coal-fired stations for electricity generation, especially particulates, SO_x, and NO_x
- heating dissipation causing misting and fogging conditions
- emissions of fluorides and its compounds, nitrogen oxides, and sulfur
- liquid effluent containing calcium, chloride, sodium, and sulfate ions
- small quantities of uranium and other radionuclides in gaseous and liquid effluent releases
- water availability
- waste storage
- setting neutralization ponds
- accident risks - fires, explosion, criticality and unintentional UF_6 releases
- transuranics and fission product contamination of process equipment and environmental releases in processing recycle fuel.

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons[a]
UF_6	8.4

ENERGY	MWh[a]
electricity	1.3×10^4

LAND	Acres[a]
temporarily committed	0.04
undisturbed area	0.03
disturbed area	0.01
permanently committed	0.0
total	0.04

WATER	Acre-Ft.[a]
discharged to air (at GDP)	10.7
discharged to water bodies (at GDP)	0.8
discharged to water bodies (at power plants)	1,407

MATERIALS[1]	Tons[c]
concrete	762.00
total steel & castings	330.00
copper, brass & bronze	11.70
aluminum & castings	7.50
manganese	1.80
chromium	2.30
nickel	0.41
cast iron	26.50
steam turbogenerators (MWe)	0.24
pumps & drivers (1000 HP)	0.27
axial compressor (1000 HP)	3.80
centrifuge compressor & driver	0.01
heat exchangers (1000 ft^2)	3.60

COSTS	Dollars (1978)[c]
construction[3]	
manpower	630,000
materials	270,000
equipment	1,070,000
other construction	490,000
land rights	10,000
(escalation during construction)	(820,000)
(interest during construction)	(1,270,000)
(working capital)	(680,000)
total	2,470,000
operation & maintenance	350,000

PERSONNEL	Workers[c]
construction (8 years)	2.8
operation	1.0

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons[a]
particulates	51.8
SO_2	197.0
NO_x	51.8
hydrocarbons	0.5
CO	1.3
F^-	0.02

WATER POLLUTANTS	Tons[a]
Ca^{++}	0.3
Cl^-	0.4
Na^+	0.4
$SO_4^=$	0.3
Fe	0.02
NO_3^-	0.12

RADIATION

Air	Curies
uranium	8.3×10^{-5}(a)
radon and daughters	NA
Tc-99m	NA
Pu-239	2.5×10^{-13}(b)
Np-237	1.3×10^{-10}(b)
Tc-99	3.4×10^{-4}(b)
Ru-106	4.6×10^{-6}(b)
Zr-Nb-95	9.5×10^{-7}(b)
Cs-137	7.0×10^{-8}(b)
Ce-144	7.0×10^{-8}(b)
Other fission products	7.0×10^{-8}(b)

WATER	Curies
uranium	8.3×10^{-4}(a)
Pu-239	5.1×10^{-12}(b)
Np-237	2.5×10^{-9}(b)
Ru-106	5.9×10^{-5}(b)
Zr-Nb-95	1.3×10^{-5}(b)
Cs-137	9.5×10^{-7}(b)
Ce-144	9.5×10^{-7}(b)
Tc-99	4.4×10^{-3}(b)

HEAT	Btus[a]
heat discharged to water	103×10^9
heat discharged to air	31×10^9

ENERGY PRODUCT	Tons[a]
enriched ^{235}U in UF_6	5.49

BY-PRODUCTS[2]	Tons
^{235}U in tails	0.01

(1) Selected materials and equipment items.
(2) This value represents the amount of U-235 (0.25%) contained in the UF_6 depleted tails assay.
(3) Costs in parentheses are not included in total.

SOURCES (a) U.S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle (Wash. 1248), 1974.
(b) U.S. Energy Research and Development Administration, Draft Environmental Statement-Expansion of U.S. Uranium Enrichment Capacity, ERDA-1543, 1975.
(c) Bechtel Corporation, Energy Supply and Planning Model, 1978.

TABLE VII-2, STEP 5

Fuel Fabrication Plant

ENERGY SYSTEM:

SIZE
- 990 tons/year supports 26 model light Water Reactors (LWRs)
- 5.49 tons produce 10^{12} Btu output
- 0.8 capacity factor
- conversion efficiency 100%
- 20 year lifetime

DESCRIPTION
- Fuel fabrication is accomplished by chemical conversion of UF_6 to UO_2 and mechanical processing including pellet production and fuel element fabrication loaded in zircoloy or stainless steel tubes, fitted with end caps and welded.

COMPONENTS

UO_2 Powder Processing
- vaporization of UF_6 in steam or electrically heated cabinet
- hydrolysis - reacting UF_6 with H_2O to form UO_2F_2 solution
- precipitation - ammonium hydroxide to convert UO_2F_2 to ammonium diuranate (ADU)
- centrifuge or filtration - concentrate ADU slurries
- calcination - ADU is calcined by heating
- reduction - ADU reduced to UO_2 powder in a reducing atmosphere (hydrogen)

Mechanical Processing
- pretreatment of UO_2 powder by comminution, compaction and granulation to obtain desired particle size
- pelletizing
- sintering of pellets in a reducing atmosphere
- grinding to finished dimensions
- washing and drying the pellets
- loading pellets into fuel rods and welding the end caps
- assemble fuel rods to form finished fuel elements

Scrap Recovery/Off-Specification Material
- dissolution of uranium in nitric acid to form uranyl nitrate
- purification of uranium through solvent extraction
- reconversion of uranium to return to UO_2 production

ENVIRONMENTAL CONCERNS
- emissions from coal-fired power plant for electricity generation
- fluorides emission from fabrication plant
- nitrogen compounds in liquid effluents from NH_4OH in UO_2 production and nitric acid recovery of scrap
- heat dissipation into environment
- radioactive contaminated CaF_2 (solid waste) retained onsite
- accident risks - rupture of UF_6 cylinder releasing U and HF, furnace explosion releasing U, and criticality accident

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons[a]
enriched ^{235}U in UF_6	5.49

ENERGY	[a]
electricity	71 MWh
natural gas	1.5×10^5 acf[a]

LAND	Acres[a]
temporarily committed	0.01
undisturbed area	0.01
disturbed area	0.002
permanently committed	0.0
total	0.01

WATER	Acre-Ft.[a]
discharged to water	0.67

MATERIALS(1)	Tons(2)[b]
concrete	74.70 - 444.0
total steel & castings	12.00 - 45.00
copper, brass & bronze	0.59 - 5.20
aluminum & castings	0.27 - 1.43
manganese	0.08 - 0.21
chromium	0.10 - 0.15
nickel	0.02 - 0.03
cast iron	0.49 - 0.90
steam turbines (1000 HP)	0.01 - 0.00
pumps & drivers (1000 HP)	0.01 - 0.04
heat exchangers (1000 ft^2)	0.00 - 0.03

COSTS	Dollars(1978)(2)[b]
construction	
manpower	60,000 - 220,000
materials	10,000 - 60,000
equipment	80,000 - 260,000
other construction	20,000 - 60,000
(land rights)	(400 - 1,000)
(escalation during construction)	(20,000 - 50,000)
(interest during construction)	(30,000 - 50,000)
(working capital)	(30,000 - 100,000)
total	170,000 - 600,000
operation & maintenance	180,000 - 260,000

PERSONNEL	Workers[b]
construction (3&2 years)	0.7 - 3.4(3)
operation	1.6 - 3.4

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons[a]
SO_2	1.10
NO_x	0.28
hydrocarbons	negligible
CO	0.01
F^-	negligible

WATER POLLUTANTS	Tons[a]
N as NH_3	0.46
N as NO_3	1.10
fluoride	0.19

SOLID WASTE	Tons[a]
CaF_2	1.20

RADIATION

Gases	Curies[a]
uranium	8.3×10^{-6}

Liquids	Curies[a]
uranium	8.3×10^{-4}
Th-234	4.2×10^{-4}

SOLID WASTE	Curies[a]
uranium (buried)	9.6×10^{-3}

HEAT	Btus[a]
heat dissipated	0.4×10^9

ENERGY PRODUCT	Tons[a]
uranium (UO_2) fuel elements	1.6

(1) Selected material and equipment items.
(2) These values represent no Pu and Pu recycle, 1st and 2nd, respectively. Costs in parentheses are not included in total.
(3) Three years are required if there is no Pu recycle, two years if there is Pu recycle.

SOURCES: (a) U.S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle (Wash. 1248), 1975.
(b) Bechtel Corporation, Energy Supply Planning Model, 1978.

TABLE VII-2, STEP 6

Light Water Reactor Nonradiological Effluents

ENERGY SYSTEM

SIZE
- 1,000 MWe Light Water Reactor (LWR)
- produces 21 x 10^{12} Btu
- 0.7 capacity factor
- conversion efficiency 33%
- 30 year lifetime

DESCRIPTION
- Light Water Reactors (LWR) consist of two types: pressurized-water reactor (PWR) which heats water without allowing it to boil and the boiling water reactor (BWR).

COMPONENTS*
- containment structure
- reactor vessel
- fuel assemblies within reactor core
- steam separator
- turbine generator
- cooling water condensor
- liquid waste system
- cooling towers
- PWR has a dual cooling system using steam generators
- BWR has only a primary cooling system
- spent fuel storage
- waste treatment systems
- auxiliary ventilation control systems
- engineered safety features

ENVIRONMENTAL CONCERNS
- airborne chemical effluents from cooling tower drift releases
- gaseous radioactive releases from power facilities (Kr-85, Kr-87, Kr-88, H-3, I-131, Xe-133)
- liquid chemical effluents from cooling systems
- liquid radioactive releases from power facilities (H-3, Co-60, Sr-89, Sr-90, Ru-106, Cs-134, Cs-137, I-131, Mn-54, Fe-59, Ce-144, La-Ba-140)
- land use
- availability of water
- spent fuel transport, storage, and disposition
- thermal effluents
- cooling water chemical effluents
- transmission lines (corridor effect on wildlife systems)
- aesthetics (cooling towers and transmission lines)
- decontamination and decommissioning at end of plant useful life
- accident risks - steam line break, rod ejection, loss of coolant, steam generator tube rupture, other transients, failure of off-gas system, and waste tanks

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons(a)
uranium (UO_2) fuel elements	1.6
LAND	Acres(b)
permanently committed	3.9
WATER	Acre-Ft(b)
losses from evaporation, drift	720
discharged to water bodies	72
MATERIALS	Tons**(c)
concrete	24,500.00
total steel & castings	3,450.00
copper, brass & bronze	104.00
aluminum & castings	31.30
manganese	18.00
chromium	20.80
nickel	3.50
cast iron	39.20
steam turbogenerator (MWe)	47.80
steam turbines (1000 HP)	1.00
pumps & drivers (1000 HP)	4.80
heat exchangers (1000 ft^2)	14.80
nuclear steam supply systems	47.80
COSTS	Dollars (1978)(c)
construction	
manpower	8,080,000
materials	3,230,000
equipment	7,980,000
other construction	6,280,000
(land rights)	(150,000)
general plant	700,000
(escalation during construction)	(11,990,000)
(interest during construction)	(13,550,000)
(working capital)	(4,150,000)
total	26,270,000
operation & maintenance	710,000
PERSONNEL	Workers(c)
construction (9 years)	29.0
operation	5.7

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons(b)
particulates	NA
chromates	8.8 x 10^{-1}
zinc	1.7 x 10^{-1}
chlorides	3.7 x 10^{-3}
WATER POLLUTANTS	Tons(b)
BOD	1.0 x 10^{-1}
chlorine	1.2
phosphate	1.8
boron	14.4
chromates	1.0 x 10^{-1}
acids	3.6
organics	2.9
SOLID WASTE	Tons
total	NA
HEAT	Btus
heat dissipated	2 x 10^{12}
ENERGY PRODUCT	Kw-hrs
electricity	2.93 x 10^{8}

*LWRs consist of a 2:1 mix of PWRs and BWRs
**Selected materials and equipment items

Note: Values reported in AEAR were derived from Bisselle, C.A., Strategic Environmental Assessment System: Radiation Residuals, MTR-6511, 1973.

SOURCES:
(a) U.S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle (Wash. 1248), 1974.
(b) The MITRE Corporation, Annual Environmental Analysis Report (AEAR), 1977.
(c) Bechtel Corporation, Energy Supply Planning Model, 1978.
(d) U.S. Environmental Protection Agency, Assessment of Carbon-14 Control Technology and Costs for the LWR Fuel Cycle, EPA 520/4-77-013, 1977.

TABLE VII-2, STEP 6, CONT.

Note: All coefficients listed below are per 10^{12} Btu produced.

Radiation Air	PWR* Curies	BWR** Curies
Ar-37	6.83×10^{-1}	NA
Ar-41	8.04×10^{-1}	3.25×10^{1}
Kr-83m	2.37×10^{-2}	9.60×10^{2}
Kr-85	3.90	1.64×10^{3}
Kr-85m	2.77	5.31×10^{2}
Kr-87	7.00×10^{-1}	1.57×10^{3}
Kr-88	2.70	1.54×10^{3}
Xe-131m	5.77×10^{-1}	1.50×10^{1}
Xe-133	4.88×10^{2}	1.52×10^{3}
Xe-133m	6.95	1.72×10^{2}
Xe-135	4.30×10^{1}	2.09×10^{3}
Xe-135m	4.21	3.62×10^{2}
Xe-137	1.14×10^{-5}	NA
Xe-138	2.87×10^{-1}	2.87×10^{3}
I-131	5.28×10^{-3}	5.54×10^{-2}
I-132	2.14×10^{-3}	NA
I-133	2.08×10^{-3}	3.31×10^{-1}
I-134	4.73×10^{-4}	NA
I-135	7.42×10^{-3}	3.59×10^{-1}
Br-82	4.01×10^{-6}	NA
C-14	1.44×10^{-1}	3.0×10^{-1}
Co-57	6.03×10^{-8}	NA

Air	PWR* Curies	BWR** Curies
Co-58	8.90×10^{-4}	1.51×10^{-4}
Co-60	2.46×10^{-4}	1.54×10^{-3}
Sr-89	3.63×10^{-5}	1.17×10^{-2}
Sr-90	6.31×10^{-6}	2.48×10^{-4}
Sr-91	5.78×10^{-4}	NA
Zr-95	3.41×10^{-7}	1.91×10^{-4}
Nb-95	5.41×10^{-7}	9.28×10^{-5}
Zr-97	8.17×10^{-6}	NA
Cs-134	4.04×10^{-5}	2.54×10^{-4}
Cs-136	7.81×10^{-7}	2.47×10^{-5}
Cs-137	2.31×10^{-4}	5.43×10^{-4}
Cs-138	1.11×10^{-3}	NA
Ba-131	1.33×10^{-7}	NA
Ba-133	1.53×10^{-7}	NA
Ba-139	6.61×10^{-8}	NA
Ba-140	7.80×10^{-5}	1.87×10^{-2}
La-140	7.80×10^{-5}	2.23×10^{-3}
H-3	7.42	6.27
Cr-51	7.38×10^{-4}	4.75×10^{-4}
Mn-54	6.78×10^{-5}	2.54×10^{-4}
Mn-56	3.13×10^{-6}	NA

Air	PWR* Curies	BWR** Curies
Rb-88	1.91×10^{-2}	5.52×10^{-7}
Mo-99	3.16×10^{-7}	2.09×10^{-4}
Tc-99m	7.99×10^{-3}	3.10×10^{-4}
Ce-139	8.32×10^{-7}	NA
Ce-141	2.16×10^{-7}	3.04×10^{-4}
Ce-144	2.26×10^{-7}	1.14×10^{-3}
Ag-108m	3.68×10^{-9}	NA
Ag-110m	1.29×10^{-6}	1.89×10^{-6}
Np-239	4.54×10^{-7}	1.66×10^{-5}
Na-24	2.29×10^{-5}	5.92×10^{-6}
Ru-103	7.36×10^{-7}	7.47×10^{-5}
Sn-123m	9.55×10^{-7}	NA
Cd-109	1.66×10^{-7}	NA
Cd-115	3.41×10^{-5}	NA
Cu-64	5.81×10^{-4}	NA
Ni-65	1.47×10^{-7}	NA
Te-132	1.80×10^{-6}	NA
Sb-124	2.86×10^{-5}	NA
Fe-59	NA	1.77×10^{-4}
Zn-65	NA	6.06×10^{-5}
As-76	NA	1.47×10^{-5}

Water	PWR* Curies	BWR** Curies
Ar-41	1.17×10^{-4}	NA
Kr-85	2.18×10^{-4}	NA
Kr-85m	6.15×10^{-3}	NA
Kr-87	1.12×10^{-4}	NA
Kr-88	3.38×10^{-5}	NA
Xe-131m	6.80×10^{-3}	NA
Xe-133	1.08	9.52×10^{-3}
Xe-133m	6.72×10^{-3}	NA
Xe-135	1.28×10^{-1}	1.44×10^{-2}
XE-135m	7.52×10^{-4}	NA
I-131	9.64×10^{-2}	1.29×10^{-2}
I-132	4.66×10^{-3}	5.28×10^{-5}
I-133	2.17×10^{-2}	8.54×10^{-3}
I-134	3.80×10^{-3}	NA
I-135	1.10×10^{-2}	1.39×10^{-3}
Be-7	1.01×10^{-3}	NA
Co-57	5.86×10^{-4}	NA
Co-58	6.31×10^{-2}	2.22×10^{-3}
Co-60	2.28×10^{-2}	1.50×10^{-2}
Fe-59	1.17×10^{-3}	2.85×10^{-3}
Na-24	5.97×10^{-2}	1.64×10^{-2}
Cr-51	1.39×10^{-2}	2.54×10^{-3}
Mn-54	6.91×10^{-3}	1.63×10^{-2}
Mn-56	1.08×10^{-5}	1.52×10^{-4}
Cu-64	2.02×10^{-4}	NA

Water	PWR* Curies	BWR** Curies
Zn-65	6.71×10^{-4}	3.29×10^{-3}
Se-75	1.10×10^{-5}	NA
Sr-85	3.09×10^{-5}	NA
Sr-89	1.91×10^{-3}	1.65×10^{-2}
Sr-90	4.43×10^{-4}	4.09×10^{-4}
Sr-91	1.20×10^{-5}	1.37×10^{-7}
Sr-92	2.84×10^{-5}	NA
Zr-95	1.07×10^{-3}	1.80×10^{-3}
Nb-95	1.29×10^{-3}	6.61×10^{-4}
Zr-97	3.94×10^{-5}	NA
Nb-97	2.72×10^{-4}	NA
Mo-99	4.22×10^{-3}	4.46×10^{-3}
Ru-103	2.40×10^{-3}	2.60×10^{-4}
Rh-106	1.72×10^{-6}	NA
Ag-108m	5.60×10^{-7}	NA
Ag-110m	5.28×10^{-3}	3.25×10^{-5}
Cs-134	4.08×10^{-2}	4.75×10^{-2}
Cs-136	5.38×10^{-4}	1.07×10^{-3}
Cs-137	5.28×10^{-2}	6.91×10^{-2}
Cs-138	9.27×10^{-7}	NA
Ba-133	6.27×10^{-6}	NA
Ba-139	7.72×10^{-6}	NA
Ba-140	1.07×10^{-3}	5.68×10^{-3}
La-140	9.93×10^{-4}	8.25×10^{-3}
Ce-134	4.09×10^{-5}	NA

Water	PWR* Curies	BWR** Curies
Ce-139	6.09×10^{-5}	NA
Ce-141	1.26×10^{-3}	3.25×10^{-4}
Ce-144	1.40×10^{-3}	NA
W-187	1.41×10^{-4}	NA
Np-239	1.69×10^{-4}	7.18×10^{-3}
H-3	2.11×10^{1}	1.14
C-14	7.53×10^{-4}	NA
Ni-65	4.15×10^{-7}	NA
Rb-88	6.66×10^{-4}	NA
Tc-99m	8.37×10^{-4}	1.43×10^{-2}
Cd-109	1.39×10^{-4}	NA
Cd-115	9.37×10^{-5}	NA
Cd-115m	1.13×10^{-5}	NA
Y-92	2.66×10^{-8}	NA
In-115m	1.13×10^{-5}	NA
Sn-113	3.54×10^{-5}	NA
Sn-117m	4.34×10^{-4}	NA
Sn-125m	3.41×10^{-4}	NA
Au-198	7.57×10^{-6}	NA
Ni-63	1.47×10^{-3}	NA
Sb-124	7.18×10^{-4}	NA
F-18	1.14×10^{-2}	NA
Ti-51	3.62×10^{-4}	NA
As-76	NA	1.34×10^{-4}
Y-90	NA	1.65×10^{-3}

Solid Waste	Curies	Curies
Total	48.7	79.0

*These residuals represent a weighted average for PWRs in operation during 1976. Representative reactors include: Babcox and Wilcox-Arkansas 1, Oconee 1, 2 & 3, Rancho Seco, and Three Mile Island 1; Combustion Engineering-Calvert Cliffs, Millstone Point 2, Palisades, and Fort Calhoun; and Westinghouse-Indian Point, Surry 1 & 2, Trojan, and Zion 1 & 2.

**These residuals represent a weight average for BWRs in operation during 1976. Representative reactors include: General Electric - Browns Ferry 1, 2 & 3, Dresden 2 & 3, Millstone Point 1, Peach Bottom 2 & 3, and Quad Cities 1 & 2.

SOURCE: U.S. Nuclear Regulatory Commission, Radioactive Materials Released From Nuclear Power Plants (1976), NUREG-0367, 1978.

U.S. Environmental Protection Agency, Assessment of Carbon-14 Control Technology and Costs for the LWR Fuel Cycle, EPA 520/4-77-013, 1977.

TABLE VII-3, STEP 1

Surface Coal Mining - Western

ENERGY SYSTEM:

SIZE
- 6 million tons per year
- 1.1×10^{14} Btu per year equivalent
- 30 year mine life
- Western area mine, Powder River Basin

DESCRIPTION
- In Wyoming and Montana, the two states which will account for most of the increase in production in the West, area strip mining is the dominant surface mining technique. After segregating the topsoil for subsequent reclamation purposes, and after blasting, the overburden (averaging 70 feet) is removed in long parallel cuts. The now exposed and blasted coal seam (averaging 25-30 feet) is removed (89 percent efficiency in terms of Btu recovered). With the exception of the first cut, overburden from each cut is placed in the previous one. Coal is loaded into trucks for transport to a coal cleaning area.- Reclamation consists of grading the spoil, replacing the topsoil and initiating revegetation.

COMPONENTS	Quantity
• trucks	11
• front end loaders	2
• scrapers	8
• draglines	2
• bulldozers	12
• drilling equipment	6
• graders	2
• coal shovel	2
• cable handler and reel	2

ENVIRONMENTAL CONCERNS
- fugitive dust and vehicular emissions
- reclamation
- alkaline mine drainage
- erosion
- noise
- aesthetics
- altered land use

RESOURCES USED:
(Per 10^{12} Btu Produced)

RESOURCE DEPLETION	
total in-place coal	59,449 tons
heat content	9,450 Btu/lb
COAL ANALYSIS	**% (by weight)**
moisture	21.5
volatile matter	34.5
fixed carbon	39.6
ash	4.4
sulfur	0.4
nitrogen	1.2
ENERGY	
fuel	0.8×10^9 Btu
electricity	1.1×10^5 kWh
LAND	**Acres**
fixed	0.4
incremental	1.8
WATER	**Acre-Feet**
consumption	3.0
COSTS	**Dollars (1977)**
construction	
total construction cost	1.32×10^6
other investments and fees	0.23×10^6
operation	
general mining cost	0.28×10^6
reclamation and sediment control	2×10^3
PERSONNEL	**Workers**
construction	
non-manual, technical	1.1
non-manual, non-technical	0.2
manual	2.2
operation	
non-manual, technical	0.7
non-manual, non-technical	0.9
manual	1.9

RESIDUALS (Per 10^{12} Btu Produced)	GROSS (Tons)	NET (Tons)
AIR POLLUTANTS		
Particulates(1)	0.2	0.08
SO_2	0.2	0.2
NO_x	2.0	2.0
hydrocarbons	0.2	0.2
CO	1.2	1.2
WATER POLLUTANTS		
Total Dissolved Solids	90.9	23.9
Iron	0.005	0.005
Manganese	0.02	0.02
Aluminium	0.006	0.006
Zinc	0.005	0.005
Nickel	0.001	0.001
Total Suspended Solids	3.0	2.3
Iron	0.002	0.02
Ammonia	0.1	0.2
Sulfate	41.1	37.7
SOLID WASTE(2)		
overburden removal	745	0
runoff treatment	NA	0

ENERGY PRODUCT
raw coal - 52,910 tons

(1) Assuming 60% reduction in fugitive dust emissions through dust suppression.
(2) Assumes all solid waste is returned to mining pits.

SOURCES: The MITRE Corporation, Annual Environmental Analysis Report, 1977.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
TRW, Ness Environmental Data Book, Volume IV, 1978.
Hittman Associates, Inc., Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume I, 1974.
Bechtel Corporation, Energy Supply Planning Model, 1978.
Bureau of Mines, Basic Estimated Capital Investment and Operating Costs for Coal Strip Mines, 1976.
Energy and Environmental Analysis, Coal and Profitability, 1979.
Bureau of Land Management, Federal Coal Management Program, Final Environmental Statement, 1979.

TABLE VII-3, STEP 2

Coal Beneficiation

ENERGY SYSTEM:

SIZE
- Process 2,857,000 tons of run-of-mine (ROM) coal each year to produce 2 million tons of clean coal
- Hourly capacity 950 tons of ROM coal
- Operates 3,000 hours per year, representing ten shifts per week, 230 days per year
- 20 year plant life
- 87.5% efficiency (in terms of Btus)
- yield by weight is 70%

DESCRIPTION
- Coal beneficiation is a process for upgrading coal prior to its use for metallurgical or utility purposes. The purpose of beneficiation is to remove impurities (i.e. ash and/or sulfur) from raw coal. The degree of beneficiation depends on the type of coal and its ultimate use. The system described on this summary sheet (level E per Phillips et al.) is a relatively intense procedure. It removes more sulfur and ash than most other types of beneficiation, and it is also more costly. The resultant cleaned coal would be used for metallurgical purposes.

COMPONENTS
- scalping screen
- crusher
- rotary breaker
- vibrator screens
- jigs
- dewatering equipment
- thickeners
- filters
- concentrating tables or hydroclones
- flotation circuits
- thermal drying

ENVIRONMENTAL CONCERNS
- particulate emissions
- solid waste disposal
- surface water contamination from settling pond overflow and/or refuse pile runoff
- possible ground water contamination from settling pond leaching
- noise

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons
run-of-mine (ROM) or raw coal (assuming one ton of ROM coal has an energy content of 22 million Btus per ton)	51,945

ENERGY(1)	
electricity	2.0×10^5 kWh
oil	5.9×10^8 Btu

LAND	Acres(2)
washing plant	0.2
loading facility	1.8
settling pond	2.3

WATER	Acre-Ft.
consumption	3.7

COSTS	Dollars (1976)
construction	4.3×10^5
operation and maintenance	3.2×10^5

PERSONNEL	Workers
construction (1 year)	8.1
operation and maintenance	1.5

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons (Gross)	Tons (Net)(3)
particulates	91	0.9
SO_2	2.7	0.005
NO_x	1.5	0.6
hydrocarbons	1.1	0.2
CO	5.4	0.2

WATER POLLUTANTS	Tons (Gross)	Tons (Net)(3)
total dissolved solids	143	33
iron	0.2	0.007
manganese	0.2	0.03
aluminum	1.1	0.04
zinc	0.06	0.005
nickel	0.01	0.003
total suspended solids	5,870	0.6
iron	4.4	0.06
ammonia	0.2	0.05
sulfates	98	18

SOLID WASTE	Tons (Gross)	Tons (Net)(3)
primary breaking	0	0
course cleaning(5)	2	2
raw-coal sizing	0	0
primary cleaning	10,157	10,157
froth flotation	5,341	5,341
thermal drying	0	0
breaking and sizing	2	2
total	15,502	15,502

HEAT
little or none

NOISE
Noise may affect workers involved in cleaning coal, but there should be little or no adverse impact on receptors near beneficiation plants.

ENERGY PRODUCT
cleaned coal

(1) These figures were calculated assuming an energy content of 12,000 btu/lb of coal (Hittman, 1974). They are national averages (assuming an energy efficiency of 91.3%) and do not apply to elaborate (i.e., level E) beneficiation in particular.
(2) These coefficients may be subject to error since the data source presented only the fixed amount of land used without specifying the plant's annual output of coal. In calculating these coefficients, it was assumed here that plant output was the same as that specified in the "size" section of this sheet.
(3) These figures are weighted national averages based upon regional coefficients projected by SEAS for 1979. The regional coefficients were weighted in terms of Btus used. Each of the coefficients shown on this sheet is equal to total national tons of residual divided by total national Btu output. These figures include residuals from refuse piles and the beneficiation process itself. They assumed that 80% of coal preparation plants are closed cycle and that all refuse is treated. An efficiency of 90% (in Btus) was assumed.
(4) Based on national averages in Hittman.

SOURCES: Phillips, Peter and Paul DeRienzo, "Assessing the Economics of Steam Coal Preparation", Coal Mining and Processing, September, 1977.
DOE and EPA, Engineering/Economic Analysis of Coal Preparation with SO_2 Cleanup Processes, 1978.
Hittman Associates, Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, 1974.
The MITRE Corporation, Annual Environmental Analysis Report, 1977.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
Schmidt, Richard A., Coal in America, 1979.
McGraw Hill Mining Information Services, Keystone Coal Industry Manual, 1977.
Bureau of Land Management, Federal Coal Management Program, Final Environmental Statement, 1979.

TABLE VII-3, STEP 3

Western Coal Unit Train

ENERGY SYSTEM:

SIZE
- One unit train carries 10,000 tons of coal per trip.
- Unit train consists of 100 freight cars each carrying 100 tons of coal.
- Four diesel locomotives of 3,000 HP each
- Ten spare freight cars are reserved for each unit train.
- Each unit train is assumed to make 90 round trips per year. Each trip is 700 miles (1126km) one way.
- 99.75% of the coal loaded on a unit train is successfully delivered to its destination—0.25% inefficiency accounts for losses in handling and wind losses in transportation.
- 30 year lifetime of cars

DESCRIPTION
- Unit trains consist of equipment dedicated to transportation of coal from a single origin to a single destination. The unit train described in this summary runs on diesel fuel (99% of all rail ton-miles in the U.S. are by diesel; 1% are on electrically-powered trains).

COMPONENTS
- freight cars
- locomotives
- caboose

ENVIRONMENTAL CONCERNS
- air pollution (particulates)
- railroad crossing hazard
- noise

RESOURCES USED:
(Per 10^{12} Btu Transported)

PRODUCT	
coal transported	53,040 tons
energy content	9,450 Btu/lb
ENERGY	Btus
diesel	1.30×10^{10}
LAND(1)	NA
MATERIALS(2)	Tons
aluminum	2.54
brass & bronze (castings)	1.02
chromium	0.13
copper	3.51
iron	NA
manganese	1.80
nickel	0.03
steel	251.33
COSTS	Dollars (1978)
construction(2)(3)(4)	
electrical equipment	68,000
miscellaneous equipment	372,000
other constructor expenses	13,000
total	454,000
operation and maintenance(5)	
ancillary energy(1) (diesel)	53,000
other	351,000
total	403,000
PERSONNEL	Workers
construction (1 year)	NA
operation & maintenance	7.02

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Transported)

AIR POLLUTANTS (6)	Tons
particulates	139.5(7)
SO_2	5.0
NO_x	4.4
hydrocarbons	3.6
CO	4.6
aldehydes, etc.	0.8

NOISE
Noise inside diesel locomotives ranges at least as high as 112 decibels (dBA). 100 feet from a moving train, noise may be approximately 95 dBA, while at 1000 feet the noise level may be about 75 dBA. Locomotive whistle noise at 1000 feet from a train has been recorded at 85 dBA, dropping below 70 dBA at 1300 feet. The amount of noise generated is affected by train speed, the number of cars in a train, track condition and topography. Welding of tracks help reduce noise, and man-made barriers can obstruct or dissipate sound emissions. Federal design noise levels range from 55 dBA (maximum desirable for residences) to 75 dBA.

ENERGY PRODUCT	Tons
transported coal	52,910

(1) Land use value has been excluded as it cannot be exclusively associated with coal transportation.
(2) These figures do not include materials (construction costs) for tracks, loading facilities and unloading facilities.
(3) This represents the costs of construction, divided by the annual volume transported.
(4) Total construction costs shown here do not include labor.
(5) O&M costs include tracks, but exclude loading facilities and unloading facilities.
(6) Uncontrolled.
(7) Includes particulates from locomotives and fugitive emissions.

SOURCES: Hittman Associates, Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume 1, 1974.
Bechtel Corporation, Energy Supply Planning Model, 1978.
International Research & Technology Corporation, TECNET, 1978.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
C. Harris, Ed., Handbook of Noise Control, 1957.
PEDCo, Inc., Environmental Assessment of Coal Transportation, 1978.

TABLE VII-3 STEP 4

Conventional Boiler - Western Coal

ENERGY SYSTEM:

SIZE
- 500 MWe
- 3,312 tons coal feed/day
- heat rate 10,000 Btu/kWh
- thermal efficiency 34%
- capacity factor 55% (national average)
- annual energy production 8.2 x 10^{12} Btu/year
- 30 year life

DESCRIPTION
- Current NSPS
  - particulates 0.1 lb/10^6 Btu (coal input)
  - sulfur oxides 1.2 lb/10^6 Btu (coal input)
- Revised NSPS
  - particulates 0.03 lb/10^6 Btu (coal input)
  - sulfur oxides reduction varies between 70% and 90% based on sulfur content and Btu content per pound of coal.

COMPONENTS
- coal
- coal crushing/conveying system
- coal pulverizing
- p. f. boiler
- turbine
- generator
- feed water treatment
- air preheater
- economizer
- flue gas desulfurization(1)
- settling ponds
- electrostatic precipitator (ESP)
- cooling towers

ENVIRONMENTAL CONCERNS
- NO_x emissions
- potential leachate of trace elements from ash/sludge
- water use (in certain areas)
- SO_2 emissions from plants

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL
coal: Western Rocky Mountain Province, 142,000 tons; heat content, 10,000 Btu/lb

COAL ANALYSIS	% (by weight)
sulfur	0.6
ash	7.7

ENERGY(2) (requirements for pollution control devices)	
electrostatic precipitator	0.89
cooling towers	4.5

LAND	Acres/Year
plant site, permanent	32.6
waste disposal area, temporary	5.9

WATER	Acre-Ft./Year
total	154.5

COSTS	Dollars
construction	NA
operation & maintenance	NA

PERSONNEL	Workers
construction	NA
operation & maintenance	8.51

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Gross	Plant Under NSPS Net	Tons Plant Under Revised NSPS Net
particulate	9024.0	147.0	44.0
SO_2	1670.0	1670.0	502.0
NO_x	1318.0	1025.0	464.0
hydrocarbons	22.0	22.0	22.0
CO	73.0	73.0	73.0
arsenic	0.14	0.007	0.007
beryllium	0.06	0.001	0.001
cadmium	0.04	0.001	0.001
fluorine	7.3	0.56	0.56
lead	0.58	0.05	0.05
mercury	0.005	0.005	0.005
selenium	0.14	0.04	0.04
manganese	2.5	0.14	0.14

WATER POLLUTANTS	Tons
BOD	1.41
COD	137.18
total suspended solids	0.33
total dissolved solids	873.53
aluminium	0.30
chromium	0.01
non-ferrous metals	110.79
zinc	0.05
sulfates	41.10
nickel	3.62
nutrients	
nitrates	1.87
ammonio	0.06
phosphorus	0.17
surfactants	0.39

SOLID WASTE (dry weight tons)

	Without Scrubbers	With Non-Regenerative Lime Scrubbers (Revised NSPS)
scrubber sludge	0	2511.0
boiler ash	2441.1	7461.1
ESP ash	8735.2	8735.2

HEAT	Btus
stack loss	0.53 x 10^{12}
cooling towers	1.41 x 10^{12}

ENERGY PRODUCT(3)	kWh
electricity per 10^{12} Btu output	2.93 x 10^8

(1) Will probably only occur under NSPS.
(2) Excludes requirements for conformance with NSPS, i.e., for an FGD system.
(3) For each Btu of electricity generated, 0.53 of energy is lost out of the stack, and 1.4 Btu of energy is lost through the cooling towers.

SOURCES: U.S. Department of Energy, Materials-Process Analysis of Coal Process Technology - Final Report for Project Phase II, 1977.
The MITRE Corporation. Annual Environmental Analysis Report, 1977.
U.S. Environmental Protection Agency, Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards fot the Steam Electric Power Generating Point Source, 1974.

Tables VII-2 and VII-3 contain information on the major pollutants associated with a 1000 MW light water nuclear reactor and a 500 MW conventional coal boiler. 2/ Each of these tables presents information on environmental impacts on a system basis, tracing the process from mining of ore through the generation of electricity. The material is presented in separate steps because of the complexity of the information involved. For both the coal and nuclear systems, the resources used, residuals and products are presented per trillion Btu's of energy produced. This allows for cross comparisons between tables. For example, the air pollutants per trillion Btu's of western coal mined can be compared to equivalent measure of uranium mined.

To understand the cumulative effects of a 1000 MW nuclear energy system, the annual energy production of the representative plant is assumed to be 21 trillion Btu/year, given the efficiency and capacity factors stated on Step 6 of Table VII-2. Therefore, the individual effects, such as air pollutants, can be multiplied by 21 to determine the cumulative impacts of a 1000 MW nuclear system. Similarly, the annual energy production of a representative 500 MW coal system is assumed to be 8.2 trillion Btu/year, given the efficiency and capacity factors stated on Step 4 of Table VII-3. Therefore, the individual effects, such as air pollutants, can be multiplied by 8.2 to determine the cumulative impact of a 500 MW coal system. The following discussion summarizes by step the data presented in the tables on the environmental impacts of light water nuclear energy systems and coal energy systems from mining to electricity generation.

1. Nuclear System

Surface mining of uranium (Table VII-2, Step 1) has a number of adverse effects on the environment. Mining impacts are relatively minimal. The mining necessary to supply a 1,000 MW nuclear plant temporarily disturbs 2.5 acres per year, and permanently disturbs less than one acre per year. Air residuals originate from the diesel powered equipment used in mining and from wind erosion, although dust suppression practices, reclamation, and revegetation of mined areas can reduce the particulates generated by wind erosion. Water pollution occurs from suspended solids produced by runoff from piles of overburden and the mined surfaces. Radiation hazards are not a problem in the low grade open-pit mines located in the United States. The residuals from transportation are negligible. There is a risk from mining accidents.

At the mine site, the milling operation (Table VII-2, Step 2) extracts uranium from the ore and concentrates it, using chemical and mechanical processes, into a semi-refined product called "yellowcake." These processes produce fumes, vapors, and dusts of a chemical and radiological nature. The processes use water which can affect the quantity and quality of water supplies, particularly ground water. Heat from the processes must be dissipated into the environment. Problems of radiological waste disposal (tailings) exist and there is risk from accidents.

While almost all of the current U.S. production of uranium comes from open-pit mining, more than half of the identified resource is located at depths accessible only by underground mining. The long-term trend is expected to be towards underground mining at higher extraction costs. Another extraction process for underground mining is "in situ leaching," also at higher cost than open-pit mining.

The conversion process (Table VII-2, Step 3) takes the yellowcake and converts it to a volatile uranium hexafluoride. This results in chemical emissions and wastes, some of which are radiological in nature. Radiological sludge has to be held for reprocessing or burial. There are problems with heat dissipation, and water availability and contamination. There also is risk of accidents. All conversion in the U.S. occurs either at sites in Oklahoma or Illinois.

Gaseous diffusion enrichment (Table VII-2, Step 4) is accomplished by passing the volatile uranium hexafluoride compound through a process resulting in an enriched product. For this process air pollutants are associated with the emissions from coal-fired electricity generation used for process power; especially particulates, NOx and SO^2. There are also air pollutants associated with the enrichment process itself. There are problems with heat dissipation, water availability, waste storage and disposal, radiological materials, and risk of accident. All enrichment in the U.S. is done by Department of Energy contractors in either Tennessee, Kentucky or Ohio.

Fuel fabrication (Table VII-2, Step 5) is accomplished by chemically converting the enriched uranium hexafluoride to a derivative and then mechanically processing it, including pellet and fuel element production. The fuel components are loaded into stainless steel tubes, fitted with end caps and welded. Air emissions result from the coal-fired generation of process power and the fabrication process itself. There are problems with heat dissipation, disposal of radioactive waste, and risk of accident. Fuel fabrication for Trojan is done in Connecticut and for Supply System Plants 1 and 2 will probably be done in Washington.

There are two types of light water reactors (Table VII-2, Step 6), the pressurized-water reactor and the boiling water reactor. There are airborne chemical effluents from the cooling towers and gaseous radioactive releases from the power facilities. There are liquid chemical effluents, some of which are radioactive. Considerable water is used. The spent fuel is presently stored at the reactor site. Provisions must be made for permanent spent fuel disposal, decontamination and decommissioning at the end of the 30 year expected life of the facility. There is also risk of accident.

2. Coal System

Following through the similar system analysis for coal-fired generation, a typical area strip mine (Table VII-3, Step 1) for western coal (Wyoming and Montana) operates by segregating the topsoil for subsequent reclamation purposes and, after blasting, the overburden (averaging 70 feet) is removed in long parallel cuts. The newly exposed and blasted coal seam (averaging 25-30 feet) is removed. With the exception of the topsoil, overburden from each cut is placed over the previous cut. Coal is loaded into trucks for transportation to a coal cleaning area. Reclamation consists of grading the soil, replacing the topsoil and initiating revegetation. Aquifers in mined areas may be permanently disrupted. Mining could displace existing land uses such as agriculture and grazing, although similar use can be made of reclaimed areas, since mining companies are required to reclaim mined lands by approximating the original topography and planting suitable vegetation. Nevertheless, the lands are irretrievably altered and the reclamation may not achieve the original productivity of the land. Opening new mines and expanding existing ones can result in significant influx of new population into remote areas and can have significant social and economic impact.

Air residuals originate from the diesel powered equipment used to dig and haul coal and overburden, and from dust due to wind erosion and vehicular operation. Reclamation and revegetation of mined areas and dust suppression practices can reduce the particulates generated by wind erosion. Water pollution occurs from suspended solids produced by runoff from piles of overburden, but under controlled conditions coal pile drainage and runoff are collected and treated prior to discharge to reduce suspended solids to a concentration of 30 parts per million (ppm) and obtain a zero acid content. There are accident risks associated with surface mining, although not as severe a risk as that associated with underground mining.

Coal beneficiation (Table VII-3, Step 2) is a nine step process for upgrading coal prior to its use for utility purposes. The purpose of beneficiation is to remove impurities, such as ash or sulfur, from the raw coal. The degree and type of beneficiation depends on the type of coal. Coal from the western states is relatively clean. The breaking and sizing processes result in noise and require small amounts of water for dust control. In addition, land is required for both breaking and sizing as well as for loading and storage facilities.

Coal can be transported (Table VII-3, Step 3) from the mine to the generating plant by train, truck, or coal slurry pipeline. A 500 MW plant would require on the average over 3,000 tons of coal per day. With new unit train cars carrying 100 tons per car, 30 cars would be used for one day's generation of electricity. Train hauling results in noise, emissions from diesel fuel combustion and wind borne particulates. These particulate emissions during transportation have been estimated to be less than 1 percent of tonnage carried by unit trains. Coal slurry pipelines require large amounts of water. For example, Peabody Coal's Black Mesa slurry pipeline requires about 11 million gallons of water per trillion Btu's of coal carried (3,200 acre-feet per year). It also requires a 62.5 foot right-of-way along its length (7.58 acres per mile) and 50 acres for each of four pumping stations.

The environmental concerns associated with the generation of electricity from a conventional boiler (Table VII-3, Step 4) consist of SO^2, CO and NOx emissions, leachate of trace elements from ash/sludge and water use. There is potential for accidents.

The chemical air emissions of coal-fired plants are of special concern. Emissions from coal plants to the atmosphere (SO^2 and NOx) can result in acid precipitation which may have corrosive effects on a variety of materials as well as potential detrimental effects on aquatic and terrestrial life. Currently, intensive research is being conducted on acid precipitation (General Accounting Office, 1981). A 1969 study in Oregon which tested 64 lakes and reservoirs for acidity found that there was no immediate problem (State of Oregon, 1981a). Since this study, the state has established permanent acidity monitors for both precipitation and bodies of water to assess the impacts of volcanic eruptions as well as coal-fired generating plants.

The second emission of major concern from the combustion of coal is carbon monoxide. This emission contributes to the problem of carbon dioxide (CO^2) in the atmosphere which is becoming a worldwide problem. The combustion of all forms of fossil fuels, not just coal, is the major source of CO^2. Concentration of CO^2 in the earth's atmosphere is known to have increased about 7 percent since 1958 and could reach levels of 30-50 percent above the 1958 level by the middle of the twenty-first century (Council on Environmental Quality, 1980, p. 265).

Atmospheric CO^2 has "greenhouse" effects by trapping heat, causing the average temperatures of the earth's surface to rise. It is estimated that a doubling of the atmospheric CO^2 concentration could raise average global surface temperatures about 3 degrees centigrade (5.4 degrees fahrenheit) and increase the winter average in the north polar region as much as 7 to 10 degrees centigrade (Council on Environmental Quality, 1980, p. 265). BPA will be closely following the results of both the SO^2 and CO^2 research efforts.

Using Tables VII-2 and VII-3, it is possible to summarize the major impacts of a coal and a nuclear generating system (mining through generation). The impacts associated with a 1000 MW nuclear generating facility and a 500 MW coal facility are summarized in Table VII-4.

3. Generation Assumptions

The environmental analysis of a coal-fired generation facility is based on data that assume a 55 percent plant factor, while for the nuclear facility a 70 percent plant factor is assumed. To estimate the nameplate "generation equivalent" for a given increment of annual decrease in power consumption, BPA assumed a 70 percent plant factor for both types of facilities, a 100 percent load factor, and a 5 percent transmission loss factor.

TABLE VII-4
MAJOR ENVIRONMENTAL IMPACTS OF REPRESENTATIVE
COAL AND NUCLEAR GENERATING SYSTEMS,
FROM MINING THROUGH GENERATION

Line No.	Type of Impact	A 1,000 MW Nuclear Plant a/	B 500 MW Coal Plant b/
1.	Total Land Use (acres)	142.8	369.0
2.	Land Disturbed-Mining (tons of overburden) c/	2,940,000.0	6,109.0
3.	Air Pollution:		
4.	Particulates	1,142.4	1,512.9
5.	SO^2	4,231.5	4159.0
6.	NOx	1,123.5	3862.2
7.	CO	27.3	647.8
8.	Solid Waste (tons) d/	87,633.0 d/	280,546.6
	Other (curies)	525.0	
9.	Water Pollutants (tons)		
10.	Solids	231,000.0 d/	7,658.0
11.	Chemical/Metallic	594.3 d/	1,611.3

a/ Annual energy production of 21 trillion Btu/year (Conversion factor: 11,500 BTu's = 1 kilowatthour).
b/ Assumes plant operates under revised Federal standards which impose environmental controls. Annual energy production of 8.2 trillion Btu/year.
c/ Assumes 100 percent land reclamation leaving no waste.
d/ Includes radioactive pollutants.

The plant factor is an estimate of the average percent of nameplate capacity at which a resource is operated over the course of a year. A 1000 MW nameplate plant, for example, could be expected to produce an average useable capacity of 700 MW, assuming a 70 percent plant factor. Staff chose 70 percent because it is approximately equal to the plant factor used in BPA's LRIC analysis (67.57 percent). Actual plant factors vary according to plant type (nuclear versus coal, for example), vintage, and specific operating and maintenance characteristics.

Load factor refers to the ratio of the average output of a plant to its peak output. Staff assumed a 100 percent load factor since coal and nuclear facilities would serve as baseload plants in BPA's generation system. In other words, these plants would be assumed to operate at their full capacity whenever they were in operation. A loss factor of 5 percent was used to estimate the power lost during transmission from point of power production to point of power consumption.

4. Residential Consumers

The consequences of an increase in BPA's wholesale rates for residential consumers are indirect. The specific effects on individual residential consumers depend on: (1) the proportion of each utility's costs devoted to the purchase of BPA power, (2) the utility's particular retail rate structure, and (3) characteristics of the individual residential consumer as described below. Because residential consumers are not able to pass along rate increases to other customers (as is the case with larger commercial/industrial businesses), these users would experience the ultimate effect of a BPA rate increase. As was described in Chapter V, the impacts of higher electricity prices are most severe for low-income residential consumers and the elderly poor on fixed incomes. This conclusion is based on the following analysis of the historic relationship of household energy costs to income level.

Table VII-5 shows, by income level, the percent of income before taxes that was devoted to energy expenditures in 1979. The proportion of income spent by the lowest income households for electricity and other energy in 1979 was over seven times as much as for the highest income households. In 1979, households with incomes less than $5,000 spent 10.8 percent of their resources on electricity, while those with incomes over $35,000 spent 1.4 percent on electricity. This relationship also holds true for other energy sources. The same high income households spent no more than 1.0 percent and 1.9 percent of their incomes on natural gas and fuel oil, respectively. Conversely, for the lowest income households, natural gas and fuel oil expenditures were 5 and 12 percent of their incomes, respectively. 3/ Thus, it can be concluded that an increase in the cost of energy will have a greater proportional impact on low income consumers because energy requires a much greater portion of their budget.

TABLE VII-5
HOUSEHOLD ENERGY EXPENDITURES AS PERCENT
OF AVERAGE ANNUAL INCOME, 1979 a/

		A	B	C	D
		Primary Heating Fuels			
Line No.	Income Level	Elect.	Natural Gas	Fuel Oil	Energy Total b/
1.	Less than $ 5,000	10.8%	5.0%	12.0%	9.8%
2.	$ 5,000 - $ 9,999	5.4	2.7	7.5	5.9
3.	$10,000 - $14,999	2.9	1.8	4.2	3.7
4.	$15,000 - $19,999	2.5	1.3	2.8	2.9
5.	$20,000 - $24,999	1.8	1.3	3.3	2.5
6.	$25,000 - $34,999	1.9	0.9	2.2	2.1
7.	$35,000 - or more	1.4	1.0	1.9	2.0

a/ Income before taxes for households in Western Region (Alaska, Arizona, Colorado, California, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming).

b/ Includes natural gas, electricity, fuel oil, kerosene, and liquid petroleum gas.

Source: U.S. Department of Energy, Energy Information Administration, Residential Energy Consumption Survey, Part II: Regional Data, 1981.

The preceding conclusion is further supported by an analysis of the historic change in electricity costs for each income group. Table VII-6 reports average annual electricity and total energy expenditures by household income levels in the years 1973 and 1979. This information demonstrates that while low and middle income households experienced nominal increases in total energy costs, they experienced substantial increases in electricity costs between 1973 and 1979 (ranging from 13.9 percent to 22.3 percent). On the other hand, the wealthiest households experienced negative growth in costs for both total energy (-2.9 percent) and electricity (-19.5 percent) over this same period. This demonstrates the ability of the wealthier consumers to rapidly respond to increasing energy costs with conservation or other measures thus reducing their total consumption.

TABLE VII-6
AVERAGE ANNUAL HOUSEHOLD ENERGY EXPENDITURES
BY INCOME LEVEL IN
1973 AND 1979

		A	B	C	D	E	F
		Electricity			Total Energy a/		
Line No.	Income Level b/	1973	1979	Percent Change	1973	1979	Percent Change
1.	Less than $ 5,000	$194	$221	+13.9	$384	$392	+2.1
2.	$ 5,000 - $ 9,999	204	235	+15.2	419	443	+5.7
3.	$10,000 - $14,999	330	264	+14.8	454	463	+1.9
4.	$15,000 - $19,999	256	313	+22.3	482	517	+7.3
5.	$20,000 - $24,999	276	302	+9.4	567	578	+1.9
6.	$25,000 - $34,999	353	384	+8.4	758	636	-16.1
7.	$35,000 - or more	483	389	-19.5	784	710	-2.9
8.	Average	285	301	+5.6	550	534	-2.9

a/ Includes natural gas, electricity, fuel oil, kerosene, and liquid petroleum gas.

b/ Before taxes in real 1979 dollars for Western Region (Alaska, Arizona, Colorado, California, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming).

Source: U.S. Department of Labor, Bureau of Labor Statistics, Consumer Expenditure Survey, 1978, and U.S. Department of Energy, Energy Information Administration, Residential Energy Consumption Survey, Part II: Regional Data, 1981.

The ability of higher income consumers to respond to increasing energy prices with conservation is further indicated by a comparison of the difference between low-income and high-income household energy expenditures over time. For example, households with a 1973 income of $5,000 or less spent an average of 149 percent less on electricity than households with incomes of $35,000 or more. By 1979, low-income households spent an average of 76.0 percent less than the upper income group. The difference in average expenditures between low and high-income households was similar for total energy costs: 104 percent in 1973 and 81 percent in 1979. This represents a sharp narrowing in the gap in energy expenditures by income groups. This is the result of high-income consumers reducing their total energy and, particularly, electricity expenditures more than low income consumers, most likely through conservation measures.

This conclusion is further supported by economic research that suggests that upper income consumers have a more elastic demand than lower income consumers in both the short and long run (Watson, 1981; Berman, 1972; Wilson, 1977). Upper income consumers more readily reduce consumption in response to a per unit increase in electricity price. As previously mentioned, this is presumably because high-income consumers are better able to make the necessary capital expenditures to rearrange their mix of electricity consuming devices. Furthermore, since a larger proportion of their use of electricity is for other than basic needs, their potential to reduce use without suffering serious deprivation to help offset the burden of electricity price increases is greater than the ability of low-income consumers.

The benefits of a higher demand elasticity are readily apparent in a hypothetical example. If it is assumed that low- and high-income household consumers have their own price elasticities of -0.3 and -0.7, respectively, a 25 percent increase in retail rates (assuming a constant base price across income groups) would cause average low-income household consumption to decline by only 7.5 percent (0.3 X 25%). In contrast, average high-income household consumption would decline by more than twice the percent of low-income household consumption (0.7 X 25% or 17.5%). All else equal, the high-income household is able to reduce consumption to compensate for the price increase while the low-income household would feel nearly the entire effect of a 25 percent increase in retail rates. Therefore, the incidence of burden relative to demand elasticity would fall disproportionately on the low-income household.

There are other household characteristics that also may influence response to increased electricity price such as homeowner-renter status, family size, structure size and thermal efficiency, location of residence, efficiency of applicances and lighting systems, and market saturation of appliances. For example, as demonstrated in Table VII-7, consumers living in rental housing in 1979 spent, on the average, only 61 percent as much on electricity as did those who own their homes. This can be explained in part by the fact that a much larger proportion of rental housing than of owner-occupied housing consists of multi-family dwellings. In addition to minimizing exterior wall surfaces, multi-family dwellings have fewer occupants per unit, are generally smaller than single family homes, and the incomes of their occupants are, on average, lower than those of homeowners.

TABLE VII-7
AVERAGE ANNUAL HOMEOWNER AND RENTER ENERGY
EXPENDITURES a/ IN 1973 AND 1979

		A	B	C	D	E	F
		Homeowner			Renter		
Line No.		1973	1979	Percent Change	1973	1979	Percent Change
1.	Electricity	$287	$347	+20.9	$156	$212	+35.8
2.	Total Energy b/	681	589	-13.5	327	422	+29.0

a/ In real 1979 dollars for Western Region (Alaska, Arizona, Colorado, California, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming).

b/ Includes natural gas, electricity, fuel oil, kerosene, and liquid petroleum gas.

Source: U.S. Department of Labor, Bureau of Labor Statistics, Consumer Expenditure Survey, 1978; and U.S. Department of Energy, Energy Information Administration, Residential Energy Consumption Survey, Part II: Regional Data, 1981.

As shown in Table VII-8, residential energy consumption also varies with family size. In 1979, four-person families spent an average of 41 percent more on their electricity bills and 27 percent more on total energy costs than two-person families. In the socioeconomic analyses performed for its 1979 Wholesale Rate Increase, BPA staff concluded that energy expenditures begin to decline after the family size exceeds five. A decrease in the growth of energy use associated with an increase in family size beyond five may be the result of strain on family income created by increased family size combined with economies-of-scale in energy use which may be achieved in larger families.

TABLE VII-8
AVERAGE ANNUAL ENERGY
EXPENDITURES BY FAMILY SIZE,
1979 a/

Line No.	Family Size	Electricity 1979	Total Energy b/ 1979
1.	One	$177	$344
2.	Two	292	522
3.	Four	412	663
4.	Five and more	441	754
5.	Average	$330	$571

a/ In real 1979 dollars for Western Region (Alaska, Arizona, Colorado, California, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming).

b/ Includes natural gas, electricity, fuel oil, kerosene, and liquid petroleum gas

Source: U.S. Department of Energy, Energy Information Administration, Residential Energy Consumption Survey, Part II: Regional Data, 1981.

E. Study of Alternative Rate Designs and Impacts

Increased public concern over environmental protection, a need to conserve natural resources, and steadily increasing utility bills aroused public interest in rate design as a mechanism to alter electricity consumption patterns. The overall objectives of rate design are: (1) to encourage efficient use of resources, (2) to recover costs from consumers in an equitable manner, and (3) to recover sufficient revenue to meet financial obligations without collecting excess revenues. At times there are inherent conflicts between these rate design objectives. For example, a design intended to recover a specific amount of revenue may do little to encourage efficient use of resources. The third objective, collecting sufficient but not excessive revenues was discussed under the revenue alternatives portion of this statement (see Chapter V). Therefore, this section will focus on the compatibility of alternative wholesale rate design concepts with the goals of efficiency and equity. Realization of these goals would have beneficial effects on both physical and social aspects of the environment.

There is a general lack of statistical evidence relating to the ability of wholesale electricity rate designs to affect the level or the efficiency of consumption at the retail level. To a large degree, this lack of data is directly related to the difficulties associated with measuring conservation savings, and with separating the wholesale energy price effect from the effect of other factors influencing consumption at a retail level, (e.g., inflation). Regardless of this statistical difficulty, it would be inappropriate to assume that wholesale price does not influence consumption. Furthermore, it would seem that a primary marketplace function of wholesale electric rates is to send price signals that are as representative as possible of the value of the commodity consumed. The correct interpretation of these signals would permit consumers to make prudent investment and consumption decisions. Conversely, distorting these signals will result in inappropriate decisions.

The central problem is to design rates that provide price signals which induce cost-effective conservation, but which minimize adverse impacts upon competing rate design objectives. The potential effects of a number of alternative rate designs on both the level and pattern of electricity consumption will be discussed in the following sections. In practice, one or more rate designs may be combined in a given rate schedule. In such instances, disaggregation of the effects of individual design characteristics may be complicated.

The Public Utility Regulatory Policies Act of 1978 (PURPA) was developed for the purpose of encouraging (1) conservation of energy supplied by electric utilities; (2) optimization of the efficiency of use of facilities and resources by electric utilities; and (3) equitable rates to electric consumers. To work towards accomplishing these objectives, PURPA sets forth certain ratemaking standards (section III(d)(1-6)) for the consideration by State regulatory authorities when reviewing retail rates. These Federal standards include (1) cost of service, (2) declining block rates, (3) time-of-day rates, and (4) seasonal rates, and will be cited, as appropriate, in the sections which follow. The cost of service standard (section III(d)(1)) applies to all rate designs and states that "Rates charged by any electric utility for providing service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class . . . ." These sections address (1) flat rates, (2) declining block rates, (3) time-differentiated rates, (4) application of the inverse elasticity rule, (5) constrained long run incremental cost pricing, and (6) tiered rates. 4/

1. Flat Rates

As presented in Chapter V, BPA rates (RF-2, IP-2, MP-2, CF-2, CE-2, NR-2, SP-1, SE-1, NF-2, RP-2, FE-2, SI-2) are flat rates, some of which are differentiated diurnally and seasonally.

Under a flat rate, a constant price is charged for each unit of electricity consumed. Although this need not be the case, flat rates usually are based on historic average system costs. If BPA were to establish a flat rate set at its marginal cost, a considerable amount of excess revenues would be produced. Approximately one-third of the large private utilities and approximately one-half of the public utilities in the Northwest have average cost based flat rates for their residential customers.

Flat rates are easy to understand and administer and, if set to recover the revenue requirement, cause no revenue stability problems. However, when based on historic average system cost, and assuming that marginal costs differ from historic average cost, flat rates give distorted signals to consumers as to the future cost of electricity because they do not reflect the true cost of new resources. Consequently, consumers are not encouraged to make efficient consumption choices because future resource costs are masked by averaging the cost of older low-cost resources with new high-cost resources (Watson, 1981, p. 33). These inefficient consumption decisions could encourage construction of otherwise unnecessary generation capacity with the resulting negative physical environmental effects associated with facility construction and operation. There also could be long run negative socioeconomic effects as a result of the poor consumption decisions brought about by distorted price signals.

2. Declining Block Rates

BPA has never had declining block rates, as its rates are based on cost-of-service. Under declining block rate designs, successive blocks of electricity are priced at progressively lower per unit prices. Traditionally, declining block rates have represented an attempt to reflect the decreasing costs per unit of production which, when electric utilities were in their initial stages of growth and development, often resulted from economies of scale and technological improvements. Consequently, declining block rates signaled customers to use increasing amounts of electricity because the per unit cost of providing those additional amounts was declining. Approximately one-third of the public utility systems in the region have declining block residential rates.

The cost conditions that at one time justified declining block rates no longer exist. The PURPA standard on declining block rates (Section III(d)(2)) states that "The energy component or a rate, or the amount attributable to the energy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric consumers may not decrease as kilowatthour consumption by such class increases during such period except to the extent that such utility demonstrates that the costs to such utility of providing electric service to such class, which costs are attributable to such energy component, decrease as such consumption increases during such period." BPA's system costs are no longer decreasing as consumption increases, primarily because the potential for developing additional low-cost hydro resources has largely been exhausted. Incremental additions to generating capability now must come from high-cost thermal plants. Faced with adding expensive thermal generation to meet load growth, the declining block rate has become an inefficient design because it inappropriately encourages consumers to increase their consumption (Watson, 1981, p. 32). Since increased consumption would require the addition of high-cost resources, declining block rates would be expected to generate ultimately higher rates for electricity. Furthermore, negative physical impacts, associated with facility construction and operation, would occur.

3. Time-Differentiated Rates

As presented in Chapter V, BPA has time-differentiated its major rates (PF-2, IP-2, MP-2, NR-2, NF-2, RP-2, and SI-2). Rates can vary by seasons and time of day. Generally, the purpose of time-differentiating rates is to reflect seasonal or diurnal differentiations in the cost of providing power during identified time periods. Typically, the cost of providing power sevices is higher during peak than during offpeak periods. During off peak periods utilities may shut down their least efficient or most costly plants which are needed only to meet peak loads. Time-differentiated rates reflect these variations in the cost of generating electricity. The PURPA standard for time-of-day rates (Section III(d)(3)) states that "The rates charged by any electric utility for providing electric service to each class of electric consumers shall be on a time-of-day basis which reflects the costs of providing electric service to such class of electric consumers at different times of the day unless such rates are not cost-effective with respect to such class . . . ." The PURPA standard for seasonal rates (Section III(d)(4)) states that "The rates charged by an electric utility for providing electric service to each class of electric consumers shall be on a seasonal basis which reflects the costs of providing service to such class of consumers at different seasons of the year to the extent that such costs vary seasonally for such utility."

Time-differentiating the rates provides customers with a price signal which appropriately conveys information concerning costs incurred relative to the times at which consumption of electricity occurs. In the Northwest, the output of the region's hydro system peaks in the spring and early summer due to runoff of melted snow, whereas the demand for electricity peaks during the winter heating seasons, necessitating additional generation or purchases of power. The daily peak demand for electricity on BPA's system occurs between 7 a.m. and 10 p.m., Monday through Saturday. The use of time-differentiated retail rates by private and public utilities varies throughout the region.

Time-differentiated rates are believed to have a potential for encouraging reduction in the use of electricity during peak times. (Economic Regulatory Commission, 1977, p. 2) This rate is considered equitable in that offpeak customers do not subsidize peak customers. Also the charging of higher rates is matched with periods of higher cost for the utility. There is a detailed analysis of time-differentiated rates in the 1979 Wholesale Rate Increase EIS (VI-9 through VI-29).

The capacity component of electricity is the prime benefactor of time differentiation of rates (California Energy Resources Conservation and Development Commission, 1977, Appendix B). Time-differentiated rates, however, seem to have little effect on the demand for energy (Uhler, 1977, p. 91). Therefore, time-of-day differentiation is less effective in a system where costs are primarily increasing because of the need for expensive thermally generated energy rather than a need for additional peaking capacity which can be met by low-cost hydroelectric facilities. In the Northwest, rates which would encourage overall reduction in consumption would be more beneficial than rates which alter the pattern of consumption without necessarily reducing it.

Although time-differentiated rates could lessen the need for construction of additional peaking capacity, they would not be expected to relieve the need for additional system energy capability. Therefore, although there might be some positive physical environmental effects associated with the lessened need for construction and operation of peaking facilities, this design would not preclude major negative impacts associated with the construction of additional baseload generation facilities.

To the extent that time-differentiated rates might smooth BPA's load shape, river flow would be less variable. A reduction in fluctuations in the use of water at generation sites may benefit fish and wildlife and enhance recreational use.

4. Application of the Inverse Elasticity Rule to Rates

As discussed in Chapter V, a rate based on the inverse elasticity rule was considered as an alternative to the PF-2 design but rejected primarily because of the absence of reliable elasticity estimates. Under the inverse elasticity approach, customers most likely to change their level of consumption in response to an increase in the price of electricity (those whose consumption is most elastic) would be charged rates closer to incremental cost than those customers who are less responsive to price. The proportion by which rates depart from incremental cost would be inversely related to the customer's ability to respond to price changes. Factors determining customer responsiveness include the ability to change use patterns, make capital improvements to enhance efficiency, change the equipment mix so as to reduce consumption, and switch to other fuel sources.

Theoretically, this design approach would promote conservation and increased efficiency in the use of facilities and resources by focusing appropriate price signals on those customers who are most likely to respond. However, controversy arises over the validity of estimates of customers' short run responsiveness to changes in price. Furthermore, it is likely that considerable variations in customer responsiveness to price occur within classes as well as between classes. The variations reflect differences between the factors that determine the ability and desire to respond to price changes. For example, the availability of substitute fuels varies widely throughout the region. Also, an individual's ability to respond to price is influenced by income, age, and level of education (Kahn, 1970, pp. 187-188). These regional and individual variations could result in considerable inequity if a single rate design based on particular price response assumptions were applied to the entire region (BPA, 1981e, p. 105).

Economic theory postulates that, in the long run, all classes of customers are responsive to price (Wilson, 1977, pp. 34-49) and, therefore, should pay approximately equal percentages of the relevant marginal costs. This long run perspective of price responsiveness negates the rationale for applying the inverse elasticity rule to electricity rates.

To the extent that application of the inverse elasticity rule to rates encourages efficient consumption, plans to develop additional generation capability may be canceled or postponed, resulting in positive physical environmental effects. However, in the short run the restructured rates would increase the price for certain customers within classes unable to respond as the whole class, and therefore could have potentially discriminatory negative socioeconomic effects.

5. Modified Long Run Incremental Cost Pricing

As described in the introduction to this chapter, and in Chapter V, rates based on long run incremental cost pricing would be set equal to the long run cost of adding generation facilities to meet load growth. Theoretically, this pricing technique would achieve the optimum distribution of resources over the long term. However, an abrupt move in the region from average cost pricing to LRIC pricing for electricity could create widespread and, in many cases, severe short term social and economic disruption. It also would result in collection of revenues in excess of BPA's requirements.

To mitigate these problems, the LRIC pricing concept could be modified in order to limit revenue collection to BPA's revenue requirement. Such a rate would consist of capacity and energy cost components in proportion to the long run incremental cost of each but at constrained levels that would not collect excess revenues. This rate design would signal consumers as to the relative value of consuming each component of electrical service, thereby encouraging more efficient consumption and investment decisions.

Constrained LRIC pricing could be expected to promote conservation and increased efficiency without creating either the widespread adverse short run socioeconomic effects of a sudden change in rate level or the problem of excess revenue collection. However, this rate design would not communicate a complete price signal to users concerning the incremental costs of capacity and energy, and would result, in BPA's case, in a significant shift in the revenue burden from capacity to energy. This could increase the potential for revenue instability as the result of many unpredictable factors (e.g., weather) affecting demand for energy.

The encouragement of efficient consumption would result in the cancellation or postponement of otherwise needed additional generation facilities. The potentially positive long run environmental effects would be both physicial and economic.

6. Tiered or Inverted Rates

This design was considered as an alternative to the proposed PF-2 rate as discussed in Chapter V. As with declining block rates, under tiered rates separate rates are charged for two or more blocks of electricity. However, with tiered rates, the rates increase with each successive block consumed and consequently are designed to have the opposite effect of declining block rates on electric consumption. Tiered rates reflect conditions of increasing cost per unit of production and signal the consumer as to this cost relationship. Approximately two-thirds of the large private utilities and one-tenth of the public utilities in the region have tiered retail residential rates.

With tiered rates there are a number of ways the amount of the initial or base block of consumption can be defined. For example, the base could be defined as consumption during a given year; consumption equal to the generation from particular resources; consumption sufficient to meet a specific set of needs; or consumption based on a combination of these factors.

A distinction should be made between an appropriate design for wholesale tiered rates and "lifeline" rates. Typically lifeline rates are applied to low income, elderly, or handicapped residential consumers, and the initial block of consumption is fixed at an amount judged sufficient to meet essential needs. Lifeline rates differ from potential wholesale tiered designs in that the primary design objective of most lifeline proposals is income redistribution, and not economic efficiency (Peseau, 1981).

Tiered rates are based on the premise that consumers respond not only to their entire bill, but also to their marginal rate for electricity. This premise was supported by a regional study which found that electrical energy demand was considerably more responsive to marginal price than to average price (Mathematical Sciences Northwest, 1976). To the extent that this premise is valid, tiered rates should promote efficient use of resources by more effectively signaling consumers as to the cost of new generation. The effectiveness of this signal is very dependent on the design specification of the block components of the rate. For example, if a consumer's total consumption is below the top tier, and if the base tier price is lower than the rate which would be employed in the absence of tiering, the effect could be an increase in consumption by that consumer. Furthermore, because of the time lag between the signal provided under a wholesale tiered rate and the ultimate consumer's decision to use or conserve electricity, it may be difficult to design an appropriate wholesale rate that would elicit the desired response from the retail consumer. This is of concern particularly because there is no assurance that the objective of the wholesale tiered rate design will be reflected in the retail rate design. In addition, tiered rates would be complex to administer and, depending upon the design characteristics, may be perceived by consumers as inequitable (BPA, 1979b).

To the extent that the tiered rate design encourages efficient consumption, construction and operation of additional generation facilities may be canceled or postponed resulting in positive physical environmental effects. Depending on the particular rate design, negative socioeconomic effects may occur in the short run as substantially increased electricity charges are assessed to high use consumers.

F. Mitigating Measures

1. Introduction

As previously noted, the no-action, proposed, and LRIC alternatives for both 1982 and the cumulative period have varying effects on the human environment. For example, the no-action alternative could necessitate the need for additional generation resources, leading to adverse effects on the physical environment. The LRIC alternative would cause rapid increases in the price of electricity leading to adverse effects on the socioeconomic environment, but would reduce the demand for electricity, thereby decreasing the need for new generation and the associated physical environmental effects.

Mitigating measures, as discussed here, are actions which reduce the severity of the adverse effects of increases in BPA's rates. This section identifies and discusses possible measures which could be applied by various entities to mitigate the potential impacts of BPA's proposed rates. These measures include existing and proposed conservation programs offered by BPA designed to assist residential, commercial, and industrial consumers.

2. Energy Efficiency Programs

BPA offered in FY 1981 and FY 1982, and is planning to offer for funding approval in FY 1983, regionwide and subregional energy conservation programs targeted at primary customer groups. In addition, BPA is planning to offer conservation programs aimed at state and local government and other nonprofit consumers in the Northwest. Space and water heating are the predominant end-uses affected by these programs. As a whole, conservation programs currently offered by BPA and proposed for FY 1983 constitute major approaches that can serve to mitigate the burden of increasing electricity prices. The applicable programs are listed below according to consumer group and the fiscal year in which they are planned for implementation. Each is then briefly described.

	Program Title	Fiscal Year
Residential Consumers	° Weatherization	1982
	° Water Heater Wrap	1981
	° Shower Flow Restrictor	1981
	° Solar/Heat Pump Water Heater	1983
Commercial/Industrial Consumers	° Lighting and Water Heating	1982
	° Lighting	1981-1982
	° Energy Audit	1982
	° Technology Transfer/Education	1982

3. Programs for Residential Consumers

a. Residential Weatherization. Residential weatherization can be one of the most effective, least cost and generally acceptable means of energy conservation currently available. BPA's residential weatherization program, together with a possible subprogram element designed to assist low-income consumers (discussed below), could go far to offset higher electricity costs associated with BPA's proposed revenue alternative. This is evidenced by the number of measures offered under the program: ceiling and attic insulation and ventilation, floor insulation, vapor barriers, unfinished wall insulation, storm doors and windows, weatherstripping, caulking, duct insulation, dehumdifiers, clock thermostats, and water and pipe insulation.

The residential weatherization program is offered to BPA's public and private utility customers who may deliver weatherization measures to their consumers through either zero interest loan or buy-back financing mechanisms. Under the former option, no-interest, deferred repayment loans may be offered to consumers based on actual weatherization retrofit costs determined by competitive bidding; capital outlays by utilities for weatherization retrofitting are not required. Under the buy-back option, BPA would reimburse participating utilities for expected energy savings resulting from measures installed in residences at a fixed rate per kilowatthour. The residential weatherization program is currently targeted as a 10 year effort and will be coordinated with related programs in place or proposed (see b-e below).

Also under consideration by BPA is a special extension of the residential weatherization program to low-income households. While a specific proposal for the low-income program is not yet finalized, this potential program could channel money through utilities, states, or community action agencies on a contractual basis, who would, in turn, administer home conservation measures. Conceivably the BPA sponsored low-income program could offer reimbursement for a portion of the costs of community outreach and home audits as well as the actual weatherization work. If adopted, the low-income weatherization program could become a continuous element of BPA's long-term conservation progams.

b. Water Heater Wrap

This program is designed to affect residential water heating by providing for the installation of supplementary insulation around electric water heaters. The Water Heater Wrap program is planned to run for three years and will be delivered through participating utilities or their agents. BPA will pay utilities for insulating individual electric water heaters in existing residences at a fixed rate for each wrap installed and inspected according to BPA specifications.

Because water heating represents approximately 22 percent of the total residential electric load in the region, large increases in electricity prices can adversely affect those consumers who rely on electric power for water heating needs. It is expected that insulating a standard electric water heater with an additional R-11 insulation will save about 435 kilowatthours per year or 10 percent of the average home's annual electric water heating requirements.

c. Shower Flow Restrictor

The Shower Flow Restrictor program is a one-year effort designed to reduce the consumption of hot water used for showers, thereby conserving electricity used for heating water. An installed shower flow restrictor can reduce electric energy consumption by reducing by one-half the amount of hot water used for showers. Implementation may be through regional utilities which purchase approved flow restrictors for distribution to residential consumers. BPA will reimburse participating utilities at a fixed rate for each restrictor distributed.

d. Solar/Heat Pump Water Heater

This program is designed to obtain greater efficiency in residential electric water heating and to displace electricity as an energy source for water heating through the application of commercially avaiable heat pump water heaters and solar water heaters. The Solar/Heat Pump Water Heater Program would be available through BPA's utility customers to single and multi-family households that use electric water heating. Reimbursement for costs would be through a buy-back mechanism similar to that employed in BPA's residential weaterization program (see item a above).

e. Flow Control

The Residential Flow Control program will further extend BPA's efforts to encourage the efficient use of electrically heated water. This effort will be achieved through the installation by participating utilities of water faucet control devices and low-flow showerheads.

The Flow Control Program, together with previously discussed water heating conservation measures, reflect BPA's efforts to provide a comprehensive approach to improving the efficiency of residential water heating and use. Expected reductions in the use of electically heated water obtained through these programs can help mitigate impacts caused by escalating residential electric energy costs.

4. Programs for Commercial/Industrial Consumers

Approximately 20 percent of the electric energy sold in the Pacific Northwest at the retail level is consumed by the commercial sector. However, a number of obstacles hinder the development of cost-effective conservation programs for commercial users. For example, most commercial buildings are leased and, as a result, conservation measures installed by the lessee typically must be compatible with the term of the lease. Moreover, the conservation measures must have a payback period shorter than the remaining term of the lease. In light of these and other constraints, BPA's conservation effort for commercial/industrial consumers is currently somewhat limited in scope. Nonetheless, it does focus on cost effective measures which demonstrate the greatest potential for electric energy savings and, consequently, provide a framework for future conservation programs for the commercial/industrial sector.

a. Commercial Lighting and Water Heating

The primary objectives of BPA's Commercial Lighting and Water Heating Conservation program are: (1) to reduce the quantity of electric energy required for lighting and water heating in commercial establishments, and (2) to provide information on additional lighting and water heating measures which can be undertaken inexpensively. The program will be implemented through participating regional utilities, with BPA reimbursing the utilities for installation of BPA approved lighting and water heating measures. These measures may include the following:

- shower flow restrictors;
- electric water heater wraps;
- rebates for installation of energy saving lamps and eligible low-flow showerheads; and
- commercial conservation information provided by BPA.

b. Commercial Lighting

(1) Lighting Conversion

The Commercial Lighting Conversion program extends BPA's current street and area lighting program to the private sector. The program design calls for interior and exterior conversion of mercury vapor, incandescent and selected fluorescent lamps to more efficient types such as high pressure sodium and metal halide. Commercial consumers would install eligible lighting systems and participating utilities would provide for conversion verification and repayment to the consumer. Reimbursement to utilities by BPA for administrative costs would be based on a set rate per retrofit, while the commercial consumer would be reimbursed one-half of the cost of the conversion lamps and fixtures up to a fixed ceiling amount.

(2) Street and Area Lighting

Most street lighting is used to illuminate arterial and residential streets. Many existing street and area lighting systems use mercury vapor or less efficient fixtures such as incandescent lamps. Through utilities, the BPA Street and Area Lighting program is designed to encourage conversion to more energy efficient systems (e.g., high pressure sodium vapor) throughout the region. Potentially, the Street and Area Lighting program could reduce, by 37 percent, the amount of energy that otherwise would be used in the region for street lighting purposes. BPA would pay utilities for both labor and capital costs associated with fixture conversion.

c. Commercial Energy Audit

The Energy Audit program is targeted for delivery through regional utilities to their commercial and industrial consumers. BPA will reimburse participating utility customers for conducting three levels of audits to identify conservation costs and savings which ultimately reduce electricity consumption. The three audit levels are: Level I, which will identify low cost and no cost operation and maintenance conservation actions; Level II, which will identify simple capital intensive conservation retrofit actions; and Level III, which will identify conservation measures for complex buildings.

d. Technology Transfer/Education

This program is designed to improve the electrical efficiency of industrial processes by: (1) providing industrial firms with energy conservation information, background, expertise and design guidelines to incorporate into their plants; and (2) providing field experience in energy conservation technologies for regional industries and to assist in the development of higher risk industrial conservation technologies. These two objectives will be met through energy conservation seminars, or workshops, feasibility studies and demonstrations directed toward the industrial sector. Seminars, or workshops, will be financed by BPA. Fiscal year 1982 seminars and workshops will be devoted to motor and motor drive efficiency. Seminars and workshops in fiscal year 1983 will be devoted to alternate industrial technology. The feasibility studies or demonstrations will focus on topics of suggested industrial conservation potential, e.g., district heating, aluminum remelt, and refrigeration waste heat utilization.

As indicated earlier, BPA is implementing, or is planning to implement, energy conservation programs for other private and public, nonprofit consumers in the Pacific Northwest. These programs include the delivery of technical assistance to state and local governments to encourage the adoption of cost-effective energy conservation measures and appropriate building codes and land use ordinances, energy conservation audits and installation of conservation measures in institutional buildings (e.g., schools and hospitals), and efficiency improvements for the transmission and distribution systems of regional utilities.

5. Billing Credits

Another measure that may mitigate the financial impact of increased electricity rates is BPA's billing credit program. Mandated by the Regional Act, billing credits are payments from BPA to eligible customers for actions taken after December 5, 1980, by those customers which reduce their power needs and thereby reduce BPA's obligation to acquire additional generation resources. An eligible customer is considered one that has signed a power sales contract with BPA pursuant to provisions of the Regional Act, and who has requested a billing credit. Payment to the customer may be in the form of either an offset to the customer's power bill or a cash payment if the amount of the credit exceeds the amount of the power bill.

Actions that reduce BPA's responsibility to acquire resources and which are eligible for billing credits include the following:

- conservation measures independently undertaken, i.e., carried out independently of actions funded or offered by BPA or included in the plan of the Regional Council, by customers or political subdivisions served by customers that (1) reduce electric power consumption and, (2) occur as a result of an increase in the efficiency of energy use, production, or distribution;

- resources constructed, completed or acquired by a customer, or a political subdivision served by the customer, including actual or planned load reduction resulting from direct application of a renewable energy resource or from a conservation measure;

- retail rate structures voluntarily implemented by customers which induce conservation or installation of consumer-owned renewable resources.

Billing credits are essentially substitutes for the acquisition of resources by BPA through independent customer activities. To the extent that higher costs, i.e., higher rates by BPA associated with new generation resources, are reduced or avoided by participation in the billing credit program, and to the extent that these lower costs are passed through to the consumer by BPA customers, consumers will be provided with a level of compensation to help mitigate impacts of increases in electricity rates.

6. Income Support

Government income support programs exist which can assist residential low-income and elderly poor consumers reduce the severity of impact of any BPA rate increase. One such program for eligible applicants (at or below 125 percent of poverty level guidelines) is the Federal Low-Income Energy Assistance Program (LIEAP). LIEAP programs and programs for the aged are administered by states in the region in conjunction with Community Action and area senior service agencies. There are typically two methods by which low-income households receive support: (1) a one time annual cash payment made to the home energy supplier, e.g. a utility on behalf of the applicant, or (2) a one time annual cash payment made directly to the applicant in those cases when the applicant is a renter or indirect energy consumer, or when the home energy supplier does not participate in the program. The size of LIEAP payments usually depends on geographic location, the type of fuel used as the primary heating source, as well as income. For example, an Oregon non-farm family of four with an income range of $5,000 - $7,500, a primary heat source of electricity and residence west of the Cascades would receive a payment of $130 in 1982 (Oregon Department of Human Resources, 1981). Eligible low-income households are asked to have energy audits of their dwellings and participate in available weatherization programs to encourage energy conservation.

G. Unavoidable Adverse Impacts

The unavoidable adverse impacts resulting from implementation of BPA's rate increases would be primarily socioeconomic in character. Effects on low-income residential consumers are of special concern. An increase in the priority firm rate, under which BPA serves publicly owned utilities and the residential and small farm load of investor-owned utilities, would necessitate increases in these utilities' retail electricity rates to consumers. To the extent that BPA's increase is passed on to the consumer in higher retail rates (which depend on each utility's cost and rate structure), consumers in the region will pay more for electricity. This increased cost of electricity would have the greatest effect on low-income consumers because they generally devote a greater proportion of their income to purchases of electricity and have less flexibility in their income to adapt to increased costs than is true for other consumers.

The cumulative effects of past and projected BPA rate increases from 1979 to 1985 would result in a wholesale rate increase of 224 percent over the five year period. This would compound the socioeconomic impacts on low-income consumers and may expand, to a broader range of income levels, the experience of serious effect.

The proposed 1982 and cumulative rate increases are not expected to have serious adverse impacts on irrigated agriculture, commercial, or industrial users because electricity costs are generally a small portion of total costs and, in many instances, increases can be passed on through as higher prices to their customers. This may not be true for marginal farms and commercial firms or the highly energy intensive industries, all of which may have difficulty achieving the energy efficiency levels necessary to remain competitive. The 1982 proposal is not expected to have serious effects on these categories of consumers. However, the effect of BPA rate increases over the cumulative period may in isolated cases prove to be a contributing factor in the discontinuation of individual commercial, industrial, or farm operations.

H. The Relationship Between Short-Term Uses of the Environment and Maintenance and Enhancement of Long-Term Productivity

This section identifies the nature of the tradeoff between various short-term uses of the environment associated with increased electricity rates relative to long-term options they may preclude. As discussed elsewhere in this statement, the short-run effects of BPA's proposed and LRIC rate alternatives would be primarily socioeconomic, resulting in significant financial impact on low-income residential consumers in particular. The full effects of BPA's rate alternatives will likely develop gradually over a period of years as consumers adjust to higher prices. For example, the anticipated increase in BPA electricity costs would, over the next 20 years, enhance the cost-effectiveness of conservation and stimulate adoption of measures to improve the efficiency of energy uses. It is expected that measures such as capital intensive home and business weatherization, replacement of inefficient energy consuming devices with more efficient ones, and changes in electricity use habits will greatly contribute to the projected declines in electricity consumption under the proposed and LRIC alternatives relative to the no-action alternative (see Chapter V).

Concerns over the effects of long-term electricity generation options for the Northwest are focused primarily on the physical environment (e.g., the rate of consumption of nonrenewable resources such as coal, oil, gas, and uranium). The depletion of nonrenewable resources would be slowed by energy conservation measures adopted by regional consumers in the face of higher electricity costs. It is estimated that the proposed rates would avoid a need which would otherwise exist under the no-action alternative for output equal to three 500 megawatt coal plants and one 1000 megawatt nuclear plant by the year 2000. Corresponding savings for the LRIC alternative would amount to eight 500 megawatt coal plants and four 1000 megawatt nuclear plants by the year 2000 (see Table V-11).

By avoiding the construction and operation of coal or nuclear generation facilities, long-term impacts on land use, the creation of solid waste, and water quality and air quality would be reduced. Additionally, minimizing regional dependence on thermal plants would free scarce capital and manpower resources for other productive uses. To the extent that the effects of coal or uranium mining, processing, and power production cannot be avoided, Federal law requires mitigation of some of these impacts (e.g., regrading and revegetation of mined areas). Other long-term effects associated with coal or uranium mining, such as destruction of underground water aquifers and contamination of ground water, would be very difficult to correct. Furthermore, the long-term options for the required isolation of high level nuclear waste from the environment for extremely long periods of time remain incompletely developed. While the Federal government is currently investigating key nuclear waste management and disposal issues, no permanent, high level waste repositories have been selected to date. The mechanical malfunction of nuclear plants combined with possible human error also pose the potential for serious environmental consequences. As in the case of the 1979 nuclear plant accident at Three Mile Island, there is the potential for the release of dangerous amounts of radioactive material into the environment and, in a worst case situation, long-term destruction of life and life support systems.

Other long-term options of the proposed and LRIC rate alternatives entail fuel switching from electricity to wood, natural gas, and, to a lesser degree, fuel oil. To the extent that switching to fossil fuels occurs, finite reserves of these resources would be depleted, and could produce associated environmental degradation, especially with regard to local air quality.

Finally, agricultural productivity would be affected by the LRIC rate alternative, especially in the case of the cumulative analysis.

I. Irreversible or Irretrievable Commitments of Resources

This section identifies natural resources which may be expended as a result of increased electricity rates as described herein. Acceleration in the depletion of natural gas would be the chief resource commitment resulting from a large increase in BPA's wholesale rates.

To the extent that increased electricity prices in the Northwest stimulate greater end use of natural gas, there would be an accompanying disturbance of other natural resources. Additional conventional onshore exploration and extraction of oil or natural gas, for instance, can cause the potential for fracturing of underground aquifers, soil erosion, decreased soil fertility, and possible subsequent stream sedimentation (DOE, 1980). Moreover, the mining, preparation, distribution and disposal activities associated with the production of synthetic fuel substitutes for natural gas can cause air quality and surface water deterioration and contamination of underground water supplies with saline mine water in addition to other natural and human resource concerns (DOE, 1980). In addition, the increased consumption of natural gas resources for energy uses which could be met by electricity could reduce the availability of these resources for consumer uses where no feasible alternatives to natural gas exist.

FOOTNOTES

1/ Percentage computed from Public Agency Data Base, 1982, Bonneville Power Administration, Portland, Oregon.

2/ Tables and explanatory information derived from U.S. Department of Energy, 1980.

3/ These results have been corroborated in an analysis done by Charles River Associates, 1978, p. 96.

4/ For additional discussion of alternative rate designs see: BPA, 1979a, 1979b, 1981b, 1981c, 1981d, 1981f, and 1981g; Economic Regulatory Administration, 1977; ICF Inc., 1981; Miedema, 1980; Watson, 1981; and White,1979.

VIII. Consultation and Coordination

A. Description of the Scoping Effort

The scoping process for the 1982 wholesale rate increase draft environmental impact statement (EIS) was designed to allow the public to become involved in defining significant alternatives, issues, and potential impacts that would be evaluated in the draft EIS. On November 15, 1981, BPA published a Notice of Intent to Prepare an Environmental Impact Statement and Announcement of Scoping Meetings in the Federal Register (46 FR 54980). The notice solicited participation in five scoping meetings held throughout the Pacific Northwest and invited written and oral comments on the scope of environmental issues to be considered in the EIS. Approximately 2,000 copies of this notice and a letter from the Administrator, asking for both public participation in the scoping meetings and written comments, were mailed to interested individuals, public interest groups, BPA customers, and Federal, State, and local agencies. In addition, the meetings were advertised in general circulation newspapers in each locality.

Prior to the meetings, BPA staff telephoned approximately 35 individuals and organizations which had either participated in BPA's 1981 rate filing or which represent particular groups or governmental agencies with an interest in the rate filing. These contacts were to solicit comments for use in compiling preliminary suggestions about the scope of the EIS for use at the scoping meetings.

Scoping meetings were held in Seattle, Washington, on November 23, 1981; Portland, Oregon, on November 24, 1981; Boise, Idaho, on November 30, 1981; Missoula, Montana, on December 1, 1981; and Richland, Washington, on December 2, 1981. At each of the meetings, BPA made a brief presentation about environmental considerations and the rate process and distributed a rate development schedule, suggested outline for the draft EIS, and summary of environmental issues and alternatives that had been identified up to that time. Meeting participants were given the opportunity to ask clarifying questions and offer comments and suggestions. Twenty-two people testified at the meetings.

B. Summary of Comments on the Scope of the EIS

BPA did not receive extensive response to its request for comment on the scope of the EIS. In addition to the twenty-two people who testified at the five scoping meetings, nine written letters were received, and less than half of the persons contacted by telephone prior to the scoping meetings offered specific comments. Not all comments addressed the scope of the EIS. Some comments were essentially clarifying questions and others were suggestions about BPA policy and rate design.

A large number of comments received focused on rate design and revenue level alternatives. Tiered rates and rates based on "phased in" long run incremental costs were two rate design alternatives of particular interest to commentators. Some commenters questioned whether the EIS should examine alternatives that are beyond BPA's legislated authority. Comments were also focused on various issues related to Washington Public Power Supply System (Supply System) costs, including treatment of Nuclear Projects Nos. 1, 2, and 3 costs in determining BPA's revenue requirement and the assignment of shared costs of Supply System Nuclear Projects Nos. 4 and 5.

Other comments received concerned impacts that would result from the proposed rate increase. Commentators stated that the EIS should include a detailed analysis of the impacts of rate increases on low-income consumers and possible mitigating measures. The effect of rate increases on irrigated agriculture was another issue that received significant attention. Various methods were proposed for limiting rate increases experienced by irrigators. Comments also were made about the decision to evaluate cumulative impacts of BPA rate increases in the EIS.

Comments and suggestions received were carefully considered by BPA staff in developing this draft EIS.

Transcripts of the scoping meetings, records of telephone contacts, and written comments about the scope of the EIS are available upon request from BPA should more complete information be desired about the comments received during the scoping process.

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BOARD OF COUNTY COMMISSIONERS, COUNTY OF BEAR LAKE, PARIS ID

BOARD OF COUNTY COMMISSIONERS, COUNTY OF BINGHAM, BLACKFOOT ID

BOARD OF COUNTY COMMISSIONERS, COUNTY OF BLAINE, HAILEY ID

BOARD OF COUNTY COMMISSIONERS, COUNTY OF BOISE, IDAHO CITY ID

BOARD OF COUNTY COMMISSIONERS, COUNTY OF BONNER, SANDPOINT ID

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BOARD OF COUNTY COMMISSIONERS, COUNTY OF CLARK,DUBOIS ID

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BOARD OF COUNTY COMMISSIONERS, COUNTY OF CUSTER, CHALLIS ID

BOARD OF COUNTY COMMISSIONERS, COUNTY OF ELMORE, MOUNTAIN HOME ID

BOARD OF COUNTY COMMISSIONERS, COUNTY OF FRANKLIN, PRESTON ID

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BOARD OF COUNTY COMMISSIONERS, COUNTY OF GEM, EMMETT ID

BOARD OF COUNTY COMMISSIONERS, COUNTY OF IDAHO, GRANGEVILLE ID

BOARD OF COUNTY COMMISSIONERS, COUNTY OF JEFFERSON, RIGBY ID

BOARD OF COUNTY COMMISSIONERS, COUNTY OF JEROME, JEROME ID

BOARD OF COUNTY COMMISSIONERS, COUNTY OF KOOTENAI, COEUR D'ALENE ID

BOARD OF COUNTY COMMISSIONERS, COUNTY OF LATAH, MOSCOW ID

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BOARD OF COUNTY COMMISSIONERS, COUNTY OF MINIDOKA, RUPERT ID

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BOARD OF COUNTY COMMISSIONERS, COUNTY OF GRANITE, PHILLIPSBURG MT

BOARD OF COUNTY COMMISSIONERS, COUNTY OF JEFFERSON, BOULDER MT

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MONTANA STATE CLEARINGHOUSE, OFFICE OF BUDGET & PROGRAM PLANNING, HELENA, MT

RESEARCH & INFORMATION SYSTEMS, DIVISION DEPARTMENT OF COMMUNITY AFFAIRS, HELENA, MT

OFFICE OF BUDGET AND PROGRAM PLANNING, OFFICE OF THE GOVERNOR, HELENA, MT

DEPT. OF NATURAL RESOURCE, AND CONSERVATION, HELENA, MT

<u>CITY/COUNTY/STATE GOVERNMENT, NEVADA</u>

BOARD OF COUNTY COMMISSIONERS, COUNTY OF HUMBOLDT, WINNEMUCCA NV

BOARD OF COUNTY COMMISSIONERS, COUNTY OF ELKO, ELKO NV

NEVADA ASSOCIATION OF COUNTIES, ZEPHER NV

NEVADA LEAGUE OF CITIES, CARSON CITY NV

<u>CITY/COUNTY/STATE GOVERNMENT, OREGON</u>

BOARD OF COUNTY COMMISSIONERS, COUNTY OF BAKER, BAKER OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF BENTON, CORVALLIS OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF CLATSOP, ASTORIA OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF COLUMBIA, ST HELENS OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF COOS, COQUILLE OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF CROOK, PRINEVILLE OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF CURRY, GOLD BEACH OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF DESCHUTES, BEND OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF DOUGLAS, ROSEBURG OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF GILLIAM, CONDON OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF HARNEY, BURNS OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF HOOD RIVER, HOOD RIVER OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF JACKSON, MEDFORD OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF JEFFERSON, MADRAS OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF JOSEPHINE, GRANTS PASS OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF KLAMATH, KLAMATH FALLS OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF MULTNOMAH, PORTLAND OR

MULTNOMAH COUNTY ENERGY COOR, DIVISION OF SUPPORT SERVICES, PORTLAND OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF POLK, DALLAS OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF TILLAMOOK, TILLAMOOK OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF UMATILLA, PENDLETON OR

BOARD OF COUNTY ECONOMIC DEV, COUNTY OF UNION, LA GRANDE OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF WALLOWA, ENTERPRISE OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF WASCO, THE DALLES OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF WHEELER, FOSSIL OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF YAMHILL, MCMINNVILLE OR

OREGON ASSN OF COUNTIES, SALEM OR

OREGON LEAGUE OF CITIES, SALEM OR

CITY MANAGER, CITY OF ASHLAND WATER & LIGHT, ASHLAND OR

A-95 COORDINATOR, INTERGOVERNMENTAL RELATIONS DIV., SALEM, OR

OREGON STATE DEPARTMENT OF ENERGY, SALEM, OR

UMPQUA REGIONAL COUNCIL OF GOVERNMENTS, ROSEBURG, OR

DEPARTMENT OF ENVIRONMENTAL QUALITY, PORTLAND, OR

OREGON DEPT. OF FISH & WILDLIFE, PORTLAND, OR

OREGON STATE CLEARINGHOUSE, INTERGOVERNMENTAL RELATIONS DIVISION, SALEM, OR

OREGON STATE DEPT. OF TRANSPORTATION, PARKS AND RECREATION DIVISION, SALEM, OR

OREGON STATE FORESTRY DEPARTMENT, OFFICE OF THE STATE FORESTER, SALEM, OR

CITY OF FOREST GROVE, FOREST GROVE OR

CITY OF MCMINNVILLE, MCMINNVILLE OR

BOARD OF COUNTY COMMISSIONERS, COUNTY OF WASHINGTON, HILLSBORO OR

CITY ADMINISTRATOR, CITY OF BANDON, BANDON OR

CITY OF MONMOUTH, MONMOUTH OR ,

CITY/COUNTY/STATE GOVERNMENT, UTAH

BOARD OF COUNTY COMMISSIONERS, COUNTY OF BOX ELDER, BRIGHAM CITY UT

UTAH ASSOCIATION OF COUNTIES, SALT LAKE CITY UT

UTAH LEAGUE OF CITIES & TOWNS, SALT LAKE CITY UT

CITY/COUNTY/STATE GOVERNMENT, WASHINGTON

ASSN ELECTED COUNTY OFFICIALS, OLYMPIA WA

GOVERNMENTAL CONFERENCE, BENTON-FRANKLIN, RICHLAND WA

OFFICE OF THE MAYOR, CITY OF ANACORTES, ANACORTES WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF ADAMS, RITZVILLE WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF ASOTIN, ASOTIN WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF BENTON, PROSSER WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF CHELAN, WENATCHEE WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF CLALLAM, PORT ANGELES WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF CLARK, VANCOUVER WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF COLUMBIA, DAYTON WA

DEPT OF COMMUNITY DEVELOPMENT, COUNTY OF COWLITZ, KELSO WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF COWLITZ, KELSO WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF DOUGLAS, WATERVILLE WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF FERRY, REPUBLIC WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF FRANKLIN, PASCO WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF GARFIELD, POMEROY WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF GRANT, EPHRATA WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF GRAYS HARBOR, MONTESANA WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF ISLAND, COUPEVILLE WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF JEFFERSON, PORT TOWNSEND WA

KING COUNTY COUNCIL, SEATTLE WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF KITSAP, PORT ORCHARD WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF KITTITAS, ELLENSBURG WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF KLICKITAT, GOLDENDALE WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF LEWIS, CHEHALIS WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF LINCOLN, DAVENPORT WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF MASON, SHELTON WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF OKANOGAN, OKANOGAN WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF PEND OREILLE, NEWPORT WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF PIERCE, TACOMA WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF SAN JUAN, FRIDAY HARBOR WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF SKAGIT, MOUNT VERNON WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF SKAMANIA, STEVENSON WA

OFFICE OF ARCHAELOGY AND HISTORIC PRESERVATION, OLYMPIA, WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF SNOHOMISH, EVERETT WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF SPOKANE, SPOKANE WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF STEVENS, COLVILLE WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF THURSTON, OLYMPIA WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF WAHKIAKUM, CATHLAMET WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF WALLA WALLA, WALLA WALLA WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF WHATCOM, BELLINGHAM WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF WHITMAN, COLFAX WA

BOARD OF COUNTY COMMISSIONERS, COUNTY OF YAKIMA, YAKIMA WA

WASHINGTON ASSN OF COUNTIES, OLYMPIA WA

WASHINGTON ASSOCIATION OF CITIES, SEATTLE WA

MAYOR, BLAINE WA

TOWN OF STEILACOOM, STEILACOOM WA

OFFICE OF COMMUNITY DEVELOPMENT, OFFICE OF THE GOVERNOR, OLYMPIA, WA

WASHINGTON STATE DEPT OF ECOLOGY, OLYMPIA, WA

NONGAME PROGRAM, WASHINGTON ST. DEPT. FISH & GAME, OLYMPIA, WA

WASHINGTON STATE DEPT. OF ECOLOGY, ENVIRONMENTAL REVIEW SECTION, OLYMPIA, WA

STATE OF WASHINGTON, DEPARTMENT OF ECOLOGY, YAKIMA, WA

CITY OF CHENEY LIGHT DEPARTMENT, CHENEY WA

TOWN OF FIRCREST, TACOMA WA

MAYOR, TOWN OF MILTON, MILTON WA

CITY OF RICHLAND, RICHLAND WA

ELECTRIC LIGHT DEPARTMENT, CITY OF CENTRALIA, CHENEY WA

CITY OF ELLENSBURG, ELLENSBURG WA

CITY OF TACOMA, OFFICE OF INTERGOVERNMENTAL AFFAIRS, TACOMA, WA

CHAMBER OF COMMERCE, TACOMA, WA

YAKIMA VALLEY CONFERENCE OF GOVERNMENTS, YAKIMA, WA

WASHINGTON STATE PARKS AND RECREATION COMMISSION, OLYMPIA, WA

CITY/COUNTY/STATE GOVERNMENT, WYOMING

BOARD OF COUNTY COMMISSIONERS, COUNTY OF LINCOLN, KEMMERER WY

BOARD OF COUNTY COMMISSIONERS, COUNTY OF TETON, JACKSON WY

WYOMING ASSN OF COUNTY OFFICIALS, LARAMIE WY

WYOMING ASSN OF MUNICIPALITIES, CHEYENNE WY

PUBLIC UTILITY COMMISSIONS

CALIFORNIA PUBLIC UTILITIES COMMISSION, SAN FRANSCISCO CA

IDAHO PUBLIC UTILITIES COMMISSION, BOISE ID

OREGON PUBLIC UTILITIES COMMISSION, SALEM OR

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION, OLYMPIA WA

PUBLIC SERVICE COMMISSIONS

PUBLIC SERVICE COMMISSION, STATE OF NEVADA, CARSON CITY NV

PUBLIC SERVICE COMMISSION, STATE OF UTAH, SALT LAKE CITY UT

PUBLIC SERVICE COMMISSION, STATE OF WYOMING, CHEYENNE WY

MONTANA PUBLIC SERVICE COMMISSION, HELENA MT

CONGRESSIONAL COMMITTES

ENERGY & NATURAL RESOURCES COMM, UNITED STATES SENATE, WASHINGTON DC

ENERGY & WATER DEV SUBCOMMITTEE, HOUSE OF REPRESENTATIVES, WASHINGTON DC

CONGRESSIONALS

HONORABLE LES AU COIN, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE MAX BAUCUS, UNITED STATES SENATE, WASHINGTON DC

HONORABLE DON L BONKER, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE HOWARD N CANNON, UNITED STATES SENATE, WASHINGTON DC

HONORABLE RICHARD CHENEY, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE LARRY CRAIG, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE ALAN CRANSTON, UNITED STATES SENATE, WASHINGTON DC

HONORABLE RON WYDEN, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE JOHN D DINGELL, CHAIRMAN SUBCOMMITTEE ON OVERSIGHT & INVESTIGATIONS

HONORABLE NORMAN D DICKS, HOUSE OF REPRESENTATIVES

HONORABLE THOMAS S FOLEY, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE SLADE GORTON, UNITED STATES SENATE, WASHINGTON DC

HONORABLE ORRIN G HATCH, UNITED STATES SENATE, WASHINGTON DC

HONORABLE MARK O HATFIELD, UNITED STATES SENATE, WASHINGTON DC

HONORABLE SAMUEL I HAYAKAWA, UNITED STATES SENATE, WASHINGTON DC

HONORABLE HENRY M. JACKSON, UNITED STATES SENATE, WASHINGTON DC

HONORABLE ABRAHAM KAZEN, JR., WATER & POWER RESOURCES SUBCOMM., WASHINGTON DC

HONORABLE PAUL LAXALT, UNITED STATES SENATE, WASHINGTON DC

HONORABLE MICHAEL LOWRY, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE RONALD C MARLENEE, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE JOHN MELCHER, UNITED STATE SENATE, WASHINGTON DC

HONORABLE SID MORRISON, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE RICHARD OTTINGER, SUBCOMMITTEE ON ENERGY CONSERVATION & POWER, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE JOEL PRITCHARD, HOUSE OF REPRESENTATIVES, WASHINGTION DC

HONORABLE BOB PACKWOOD, UNITED STATES SENATE, WASHINGTON DC

HONORABLE JAMES D.SANTINI, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE ALAN SIMPSON, UNITED STATE SENATE, WASHINGTON DC

HONORABLE DENNY SMITH, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE STEVEN SYMMS, UNITED STATES SENATE, WASHINGTON DC

HONORABLE MORRIS K UDALL, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE MALCOLM WALLOP, UNITED STATES SENATE, WASHINGTON DC

HONORABLE JAMES WEAVER, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE PAT WILLIAMS, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE JAMIE L.WHITTEN, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE RON WYDEN, HOUSE OF REPRESENTATIVES, WASHINGTON DC

HONORABLE AL SWIFT, HOUSE OF REPRESENTATIVES, WASHINGTON DC

CUSTOMERS

WAHKIAKUM COUNTY PUD, CATHLAMET WA

VIGILANTE ELECTRIC COOP INC, DILLON MT

PRAIRIE POWER COOPERATIVE INC, FAIRFIELD ID

FLATHEAD IRRIGATION PROJECT, ST IGNATIOUS MT

CARBORUNDUM COMPANY, VANCOUVER WA

ALUMINUM COMPANY OF AMERICA, WENATCHEE WA

ALUMINUM COMPANY OF AMERICA, VANCOUVER WA

REYNOLDS METALS COMPANY, RICHMOND VA

BENTON COUNTY PUD NO 1, KENNEWICK WA

UTAH POWER & LIGHT COMPANY, SALT LAKE CITY UT

FARMERS ELECTRIC COMPANY, RUPERT ID

WASHINGTON PUD'S ASSOCIATION, SEATTLE WA

TOWN OF EATONVILLE POWER & LIGHT, EATONVILLE WA

OKANOGAN COUNTY PUD NO 1, OKANOGAN WA

COLUMBIA RURAL ELEC ASSN INC, DAYTON WA

RURAL ELECTRIC COMPANY, RUPERT ID

IDAHO POWER COMPANY, BOISE ID

KLICKITAT COUNTY PUD, GOLDENDALE WA

LOS ANGELES DEPT WATER & POWER, LOS ANGELES CA

REYNOLDS METALS COMPANY, PORTLAND OR

BENTON RURAL ELECTRIC ASSOCIATION, PROSSER WA

CHELAN COUNTY PUD NO 1, WENATCHEE WA

LIGHT DEPARTMENT, CITY OF PORT ANGELES, PORT ANGELES WA

FERRY COUNTY PUD NO 1, REPUBLIC WA

DOUGLAS ELECTRIC COOP INC, ROSEBURG OR

ELMHURST MUTUAL POWER & LIGHT CO, TACOMA WA

GRAYS HARBOR COUNTY PUD NO 1, ABERDEEN WA

CLATSKANIE PUD, CLATSKANIE OR

SACRAMENTO MUNICIPAL UTILITY DIST, SACRAMENTO CA

OHOP MUTUAL LIGHT COMPANY, EATONVILLE WA

MCCLEARY LIGHT & POWER, MCLEARY WA

PACIFIC POWER & LIGHT COMPANY, PORTLAND OR

CLEARWATER POWER COMPANY, LEWISTON ID

WEST KOOTENAY POWER & LIGHT CO, TRAIL BC CANADA

PUGET SOUND POWER & LIGHT COMPANY, BELLEVUE WA

LAKEVIEW LIGHT & POWER COMPANY, TACOMA WA

SAN DIEGO GAS & ELECTRIC COMPANY, SAN DIEGO CA

CITY OF DRAIN LIGHT & POWER, DRAIN OR

ELECTRIC POWER SUPPLY, UNION CARBIDE CORPORATION, DANBURY CT

MUNICIPAL WATER & POWER DEPT., CITY OF PASADENA, PASADENA CA

UNITY LIGHT & POWER COMPANY, BURLEY ID

CONSUMER POWER, INC., CORVALLIS OR

MONTANA POWER COMPANY, BUTTE MT

WASHINGTON WATER POWER COMPANY, SPOKANE WA

ORCAS POWER AND LIGHT COMPANY, EASTSOUND WA

SALEM ELECTRIC, SALEM OR

SURPRISE VALLEY ELEC CORPORATION, ALTURAS CA

INLAND POWER & LIGHT COMPANY, SPOKANE WA

MILTON-FREEWATER LIGHT AND POWER, MILTON-FREEWATER OR

COLUMBIA POWER COOP ASSOCIATION, MONUMENT OR

UMATILLA ELECTRIC COOP ASSN, HERMISTON OR

KOOTENAI ELECTRIC COOPERATIVE, HAYDEN LAKE ID

RAFT RIVER RURAL ELECTRIC COOP, MALTA ID

LOST RIVER ELECTRIC COOP INC, MACKAY ID

MISSOULA ELECTRIC COOP INC, MISSOULA MT

RAVALLI COUNTY ELECTRIC COOP INC, CORVALLIS MT

FLATHEAD ELECTRIC COOP INC, KALISPELL MT

SALMON RIVER ELECTRIC COOP, CHALLIS ID

EAST END MUTUAL ELECTRIC CO LTD, RUPERT ID

LINCOLN ELECTRIC COOPERATIVE, EUREKA MT

GLACIER ELECTRIC COOP INC, CUT BANK MT

EUGENE WATER AND ELECTRIC BOARD, EUGENE OR

MIDSTATE ELECTRIC COOP INC, LA PINE OR

HOODRIVER ELECTRIC COOPERATIVE, ODELL OR

CENTRAL ELECTRIC COOP INC., REDMOND OR

CROWN ZELLERBACH CORPORATION, WEST LINN OR

TACOMA CITY LIGHT, TACOMA WA

NORTHERN LIGHTS, INC., SANDPOINT ID

GEORGIA-PACIFIC CORPORATION, ATLANTA GA

LOWER VALLEY & LIGHT INCORPORATED, AFTON WY

GRANT COUNT PUD NO 2, EPHRATA WA

HANNA MINING COMPANY, CLEVELAND OH

CP NATIONAL CORPORATION, BAKER OR

SEATTLE CITY LIGHT, SEATTLE WA

BIG BEND ELECTRIC COOP INC, RITZVILLE WA

CROWN ZELLERBACH CORPORATION, SEATTLE WA

KAISER ALUMINUM & CHEMICAL CORP, TRENTWOOD WA

MASON COUNTY PUD NO. 3, SHELTON WA

ALDER MUTUAL LIGHT COMPANY, EATONVILLE WA

COOS-CURRY ELECTRIC COOP., INC., COQUILLE OR

INTERCOMPANY POOL, SPOKANE WA

PORTLAND GENERAL ELECTRIC, PORTLAND OR

WEST OREGON ELECTRIC COOP INC, VERNONIA OR

ANACONDA COMPANY, COLUMBIA FALLS MT

MEAD PLANT, KAISER ALUMINUM & CHEMICAL CORP., SPOKANE WA

WHATCOM COUNTY PUD NO. 1, BELLINGHAM WA

WELLS RURAL ELECTRIC CO., WELLS NV

RIVERSIDE ELECTRIC COMPANY, RUPERT ID

TACOMA CITY LIGHT, TACOMA WA

WASCO ELECTRIC COOP INC, THE DALLES OR

COLUMBIA BASIN ELECTRIC COOP, HEPPNER OR

CONSOLIDATED IRRIGATION DIST. 19, GREENACRES WA

PARKLAND LIGHT & WATER, TACOMA WA

HANNA NICKEL SMELTING CO., RIDDLE OR

KITTITAS COUNTY PUD NO. 1, ELLENSBURG WA

CENTRAL LINCOLN PUD, NEWPORT OR

FALL RIVER RURAL ELEC COOP INC, ASHTON ID

INDUSTRIAL CUSTOMERS OF BPA, PORTLAND OR

NESPELEM VALLEY ELEC COOP INC, NESPELEM WA

SKAMANIA COUNTY PUD, CARSON WA

INDUSTRIAL CUSTOMERS, SEATTLE WA

MASON PUD NO 1, SHELTON WA

OKANOGAN COUNTY ELECRIC COOP.INC., WINTHROP WA

LINCOLN ELECTRIC COOPERATIVE, INC, DAVENPORT WA

PACIFIC GAS & ELECTRIC COMPANY, SAN FRANCISCO CA

VERA IRRIGATION DISTRICT NO 15, VERADALE WA

KAISER ALUMINUM & CHEMICAL CORP, OAKLAND CA

REYNOLDS METALS COMPANY, RICHMOND VA

MARTIN MARIETTA ALUMINUM INC, THE DALLES OR

SOUTHERN CALIFORNIA EDISON CO, ROSEMEAD CA

PACIFIC COUNTY PUD NO 2, RAYMOND WA

STAUFFER CHEMICAL COMPANY, MT PLEASANT TN

GEORGIA PACIFIC CORPORATION, BELLINGHAM WA

FRANKLIN COUNTY PUD, PASCO WA

ALUMAX PACIFIC CORPORATION, PORTLAND OR

MINING & METALS DIVISION, UNION CARBIDE CORPORATION, PORTLAND OR

INTALCO ALUMINUM CORPORATION, FERNDALE WA

INDUSTRIAL CHEMICALS DIVISION, PENNWALT COPPORATION, TACOMA WA

GEORGIA-PACIFIC CORPORATION, PORTLAND OR

INTERCOMPANY POOL, SPOKANE WA

PENINSULA LIGHT COMPANY, GIG HARBOR WA

CASCADE LOCKS CITY LIGHT,CASCADE LOCKS OR

SNOHOMISH COUNTY PUD NO. 1, EVERETT WA

ANACONDA COMPANY, VANCOUVER WA

PUBLIC UTILITY DISTRICT #1, CLALLAM COUNTY, PORT ANGELES WA

TROUTDALE PLANT, REYNOLD METALS CO., TROUTDALE OR

LEWIS COUNTY PUD, CHEHALIS WA

PEND OREILLE COUNTY PUD NO.1, NEWPORT WA

KAISER ALUMINUM & CHEMICAL CORP., TACOMA WA

LONGVIEW PLANT-PRIMARY METALS, REYNOLDS METALS CO., LONGVIEW WA

CANBY UTILITY BOARD, CANBY OR

DOUGLAS COUNTY PUD NO. 1, EAST WENATCHEE WA

INORGANIC CHEMICALS DIVISION, PENNWALT CORPORATION, PORTLAND OR

TILLAMOOK PEOPLES UTILITY DIST., TILLAMOOK OR

PUBLIC UTILITY DISTRICT #1, COWLITZ COUNTY, LONGVIEW WA

ALUMINUM DIVISION, KAISER ALUMINUM & CHEMICAL CORP, SPOKANE WA

CLARK COUNTY PUD, VANCOUVER WA

ALUMAX INC., SAN MATEO CA

INTALCO ALUMINUM CORPORATION, PORTLAND OR

MARTIN MARIETTA ALUMINUM INC, BETHESDA MD

ANACONDA COMPANY, LOUISVILLE KY

LOS ANGELES DEPT. OF WATER & PWR., LOS ANGELES CA

INTEREST GROUPS

CLEARWATER CONSERVATION FORUM, LEWISTON, ID

ENERGY AND MASS ENVIRONMENT, CALDWELL, ID

IDAHO CITIZENS COALITION, BOISE, ID

IDAHO CONSERVATION LEAGUE, BOISE, ID

IDAHO ENVIRONMENTAL COUNCIL, IDAHO FALLS, ID

KOOTENAI ENVIRONMENTAL ALLIANCE, COEUR D'ALENE, ID

IDAHO WILDLIFE FEDERATION, COEUR D'ALENE, ID

PACIFIC NORTHWEST CONSERVATION COUNCIL, BOISE, ID

LEAGUE OF WOMEN VOTERS OF IDAHO, BOISE, ID

LOST RIVERS-LEMHI RANGE WILDERNESS COUNCIL, POCATELLO, ID

SAWTELLE CHAPTER OF OUTDOORS UNLIMITED, ST. ANTHONY, ID

SOIL CONSERVATION SOCIETY OF AMERICA, BOISE, ID

WILDERNESS SOCIETY, BOISE, ID

WILDLIFE SOCIETY, IDAHO CHAPTER, U.S. FOREST SERVICE, COEUR D'ALENE, ID

WILDLIFE RESOURCES, INC., TROY, ID

MONTANA WILDERNESS ASSN., HELENA, MT

WESTERN ENVIRONMENTAL TRADE ASSOCIATION, COLUMBIA FALLS, MT

ENVIRONMENTAL LIBRARY, UNIVERSITY OF MONTANA, MISSOULA, MT

SIERRA CLUB, UPPER MISSOURI GROUP, HELENA, MT

ENVIRONMENTAL INFORMATION CENTER, HELENA, MT

SIERRA CLUB, MISSOULA, MT

FLATHEAD CITIZENS FOR SAFE ENERGY, WHITEFISH, MT

ENVIRONMENTAL QUALITY CONTROL, HELENA, MT

FLATHEAD ENVIRONMENTAL REPORT, KALISPELL, MT

CENTRAL CASCADES CONSERVATION COUNCIL, SALEM, OR

CLATSOP ENVIRONMENTAL COUNCIL, ASTORIA, OR

COLUMBIA RIVER FISHERMAN'S PROTECTIVE UNION, ASTORIA, OR

CONSUMER POWER LEAGUE, PORTLAND, OR

1000 FRIENDS OF OREGON, PORTLAND, OR

HEALTHY ENVIRONMENT ACTION LEAGUE, AZALEA, OR

IZAAC WALTON LEAGUE, PORTLAND, OR

LEAGUE OF WOMEN VOTERS OF OREGON, SALEM, OR

MID - COLUMBIA CONCERNED CITIZENS, THE DALLES, OR

NATIONAL AUDUBON SOCIETY CORVALLIS CHAPTER, CORVALLIS, OR

ENERGY CONSERVATION COALITION, LAKE OSWEGO, OR

NEW AMERICAN MOVEMENT, EUGENE, OR

NATIONAL WILDLIFE FEDERATION, PORTLAND, OR

NATURE CONSERVANCY, PORTLAND, OR

OREGON ENVIRONMENTAL COUNCIL, PORTLAND, OR

OREGON LEAGUE OF ENVIRONMENTAL VOTERS, PORTLAND, OR

OREGON SHORE CONSERVATION COALITION, ROCKAWAY, OR

OREGON WILDLIFE FEDERATION, SALEM, OR

OREGON COMMON CAUSE, EUGENE, OR

SIERRA CLUB, PORTLAND, OR

MARY'S PEAK GROUP, SIERRA CLUB, CORVALLIS, OR

SIERRA CLUB - ROGUE GROUP, GOLD HILL, OR

WESTERN FORESTRY AND CONSERVATION ASSOCIATION, PORTLAND, OR

WILDERNESS SOCIETY, PORTLAND, OR

EUGENE FUTURE POWER COMMITTEE, EUGENE, OR
ENVIRONMENTAL STUDIES CENTER, UNIVERSITY OREGON, EUGENE, OR
WATER RESOURCES PROGRAM, NATIONAL WILDLIFE FEDERATION, WASHINGTON, DC

GREENPEACE FOUNDATION, EUGENE, OR

LEAGUE OF WOMEN VOTERS OF CENTRAL LANE COUNTY, EUGENE, OR

TROJAN DECOMMISSIONING ALLIANCE, EUGENE, OR

NORTHWEST COALITION FOR ALTERNATIVES TO PESTICIDES, EUGENE, OR

OREGON WILDLIFE FEDERATION, PORTLAND, OR

CLATSKANIE-QUINCY CITIZENS' PUBLIC ADVISORY COMMITTEE, CLATSKANIE, OR

RAINIER-FERNHILL CITIZENS' PUBLIC ADVISORY COMMITTEE, RAINIER, OR

SCAPPOOSE-SPITZENBERG CITIZENS' PUBLIC ADVISORY COMMITTEE, SCAPPOOSE, OR

METROPOLITAN SERVICE DISTRICT, PORTLAND, OR

BIRKENFELD-MIST CITIZENS' PUBLIC ADVISORY COMMITTEE, RAINIER, OR

AUDUBON SOCIETY, SEATTLE, WA

CITIZENS AGAINST TOXIC HERBICIDES, CLARKSTON, WA

ECOTOPE GROUP, SEATTLE, WA

FEDERATION OF WESTERN OUTDOOR CLUBS, SEATTLE, WA

FRIENDS OF THE EARTH, SEATTLE, WA

WASHINGTON STATE SPORTSMEN'S COUNCIL, INC., TACOMA, WA

INLAND EMPIRE BIG GAME COUNCIL, SPOKANE, WA

LEAGUE OF WOMEN VOTERS, SEATTLE, WA

NORTH CASCADES CONSERVATION COUNCIL, SEATTLE, WA

OLYMPIC CONSERVATION COUNCIL, PORT ANGELES, WA

PIERCE COUNTY ACTION, TACOMA, WA

PUGET SOUND CHAPTER OF THE OCEANIC SOCIETY, SEATTLE, WA

RICHLAND ECOLOGY COMMISSION, RICHLAND, WA

SIERRA CLUB, SEATTLE, WA

SIERRA CLUB - PUGET SOUND GROUP, SEATTLE, WA
MONTANA HISORICAL SOCIETY, HELENA, MT

SIERRA CLUB - YAKIMA RIVER GROUP, YAKIMA, WA

STOP TOXIC OVERSPRAY OF PESTICIDES, KIRKLAND, WA

WASHINGTON ENVIRONMENTAL COUNCIL, SEATTLE, WA

WA FOREST PROTECTION ASSOCIATION, OLYMPIA, WA

NORTH CASCADES CONSERVATION COUNCIL, SEATTLE, WA

BONNEVILLE ELECTRIC RATEPAYERS ORGANIZATION, PROSSER, WA

THE WILDERNESS SOCIETY, WESTERN REGIONAL OFFICE, DENVER, CO

FRIENDS OF THE EARTH, WASHINGTON, D.C.

LEAGUE OF WOMEN VOTERS, MISSOULA MT

ENVIRONMENTAL LAW COMMITTEE OF YOUNG LAWYER'S SECTION OF SEATTLE-KING COUNTY BAR ASSC., SEATTLE, WA

NORTHWEST ENVIRONMENTAL DEFENSE CENTER (NEDC), PORTLAND, OR

NORTHWEST FUND FOR THE ENVIRONMENT, SEATTLE, WA

ENVIRONMENTAL DEFENSE FUND, WASHINGTON, D.C.

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XII. COMMENTS RECEIVED ON THE DRAFT ENVIRONMENTAL IMPACT STATEMENT AND BPA'S RESPONSES

NOTES

COMMENT LETTERS

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Braden, Joe
OP

5-2-82

DIVISION OF
POWER MANAGEMENT
No. R-82-215 Date 5/7
Referred to:
Action Taken:
☐ Ans. ☐ No Reply
By Date

B.P.A.
PORTLAND

JOE BRANDEN
98524 CAMELLIA DR
BROOKINGS, OR 97415

DEAR SIRS:

YOU CAN'T ATTRACT BADLY NEEDED INDUSTRY TO THE N.WEST WITH HIGH POWER COSTS.

THE WORD IS OUT THAT POWER NEEDS WERE OVER ESTIMATED - DEMAND IS DOWN.

LOWER THE RATES AND CONSUMPTION WILL INCREASE. I CAN STOP SHIVERING IN A COLD HOUSE. RETIREES ARE ON FIXED INCOME. INFLATION IS SUPPOSED TO BE IN CHECK BUT NO ONE HAS TOLD THE FEDERES. BPA OR THE UTILITIE COMPANIES, THE SCHOOL BOARDS, THE STATE, COUNTY AND CITY GOVERNMENTS. THEY ALL WANT MORE MONEY. ITS A NO WIN SITUATION. MOTH BALLING THE N. PLANTS IS THE WRONG WAY TO GO.

WE NEED A SURPLUS OF POWER, AND LOW RATES. INDUSTRY WILL COME HERE INSTEAD OF MOVING TO THE SOUTH.

YOU'LL SELL THE SURPLUS OF POWER AND PAY FOR YOUR INVESTMENT, PEOPLE WILL GO BACK TO WORK AND START PAYING TAXES AGAIN AND THE FED BUDGET DEFICIT WILL DROP TO A ~~TO~~LERABLE LEVEL AND EVERYBODY WILL BE HAPPIER.

THE LUMBER INDUSTRY BOOMED IN THE N. WEST BECAUSE WE HAD A LOT OF TREES. A LOT OF CHEAP POWER WILL AGAIN BRING BACK A BOOMING ECONOMY. TRY IT IT WILL WORK. SINCERELY

Lee Branden

Letter retyped from original.

Mrs. Leonard Kile
Rt. 1 Box 42
Odessa, Wn 99159
(Big Bend Electric Coop user)
5/3/82

Bonneville Power Administration
Mr. Peter Johnson, Adm.
P.O. Box 3621
Portland, Oregon 97208

Sir:

I am writing about my concern of the high and fast rising cost of our electricity.

We are already paying far too much for our electricity. An average household pays $65.00 a month for utilities alone, no heat expense added.

Why should we (users) pay for someone else's mistake that is now being abandoned? If the project WHOOPS should have been finished the expense would have been bad enough but now we'll see no benefit.

I feel we're paying more than our fair share for northwest electricity now. Middle income and low income people cannot afford any more price hikes.

/s/ Mrs. Kile

Pierce, John A.

DIVISION OF POWER MANAGEMENT	
No. R-82-213	Date 5/7
Referred to:	
Action Taken: ☐ Ans. ☐ No Reply	
By	Date

Malta, Idaho 83342

30 April 1982

Ms. Donna L. Geiger
Public Involvement Coordinator
Bonneville Power Administration
P. O. Box 12999
Portland, Oregon 97212

RE: Statement presented to B.P.A. rate hearing Boise, Idaho, April 14, 1982.

Dear Ms. Geiger:

My name is John A. Pierce. I ranch near Malta, Idaho and purchase power from Raft River Rural Electric Cooperative, Inc.

I irrigate 840 acres with 5 well pumps and 3 booster pumps. I also have river water to supplement the well water. Due to the nature of the growing season in this valley, crops are limited to hay and grain.

During the last three years I have made every improvement possible to make my irrigation system efficient and conserve electricity. This included new pump bowls, redesigning the irrigation system, pivots and combining river water and pump water for 100% sprinkler. This cost approximately $195,000 or if amortized over 10 years at present interest rates this figure is doubled. This amounts to $464 per acre.

I know B.P.A. is extensively promoting pump efficiency testing, but when one looks at the dollars there is a question if they are spent wisely. The dollars per acre per year looks like this:

System improvement - amortized over 10 years	$ 46.00
Labor savings	-6.00
	40.00
Energy and demand charges	25.41
	$ 65.41

This $65+ is the cost per year for the next ten years assuming there is no rate increase. This figure is approximately 10% of the value of the land. This represents a 58% increase in KWH used since 1974 and demonstrates that to improve efficiency does not always mean reducing KWH.

The most efficient pump is of no value unless it is combined with an efficient system to apply the water as required by the plants. Also this indicates that improving efficiency is not necessarily cost effective.

Even without using a return on our investment there is no profit in ranching. The land is really the only value left in my operation. Your increased rates are now decreasing my land values and will increase the percentage of the cost of irrigation to the value of the land.

I have visited with the Cassia County Assessor, Calvin Heiner, who furnished the following interesting information:

> Every $1 increase in water cost decreases the market value for tax purposes by an estimated $10 per acre and actual sale value by an estimated $20 per acre.
>
> This translates into a tax valuation shift from agricultural property to other classes of property, i.e. residential, commercial, industrial properties.
>
> Presently Cassia County has 276,963 acres of irrigated land of which Burley Irrigation District has 48,000 acres under gravity, leaving approximately 206,066 acres or 90% of the balance is pump irrigated.
>
> Every $1 increase in water costs will reduce the Cassia County tax base an estimated $2,060,660.

Although food in some forms is considered in surplus, it is fast becoming a pawn in world politics and in the balance of trade. Colorado, Idaho and Utah universities have shown that every cow on the range for one month contributes $40 - $70 to the local economy. This concept also applies to beets, beans, hay, etc. This impact to the local economy is reflected by purchases of tractors, trucks, supplies, taxes, etc. You must recognize the far reaching effects of your rate increases. If the pumps don't go on the dollars stop flowing.

I was on the Raft River Electric board when you issued the 'notice of insufficiency'. You also indicated that you were working jointly with WPPSS on nuclear plants 1 and 2 by way of guarantees and net billings. Also that at the time of our contract expiration you would have no sympathy for any Co-op who had not arranged for a power supply. This influenced the board to sign the WPPSS contract.

30 April 1982

You specifically told us our load growth would be 3%. Now you are projecting a 1.5% load growth. One percent growth indicates that the Northwest, the fastest growing region in the U.S., will have practically no growth in industry or business and practically no population growth. There is an error somewhere in these projections.

Our valley was developed and our economy is based on pump irrigation which you encouraged by way of your rates and the irrigation discount of approximately 15%, now you have taken this away. Our Co-op load is about 83% irrigation. I can live with the increased power for my house, but irrigation is my livelihood.

You must recognize the far reaching effects of your rate increases. There is a question in some of our minds as to whether we can justify turning on some of our pumps. When pumps are left idle that is a loss of revenue to the Co-op and in order to meet fixed costs rates will have to be raised to the remaining pumps. This could snowball into bankruptcy of the Co-op and pumpers.

I believe there are things you could do to help irrigation pumping and prevent bankruptcy of the farms and the electric Co-op. Because of your previous involvement and mistakes, I think you have an obligation to provide some relief. I would suggest a few things:

1. Do not increase rates.
2. The irrigation rates for April and May should be on the summer schedule. Normally you are spilling water during these months.
3. You are spending 5 to 6% of the firm resource revenue projection of your budget for conservation. I assume 5 to 6% of my pump bill goes to conservation. We are doing everything we can for conservation as individuals and as a Cooperative; don't make us pay twice. Reduce our bill 5 to 6%.
4. I understand a Nickle mining company within the Willamette Valley has been given special consideration for their rates. You certainly can justify reinstating the 15% irrigation discount.
5. Your policy indicates that customers in the northwest have a priority for power produced in the northwest. When dump power is sent to California their rate should be the equivalent of our rate and during the dump period we in the northwest should receive our power at the dump rate.

30 April 1982

I hope you will give consideration to the things I have mentioned because the rest of the pumpers in the valley are in the same situation that I am in. Most pumpers are more severely impacted because I am in a low pumping lift area and I also have river water that only needs to be pressurized for sprinklers.

Thank you for the opportunity to give you my imput. This statement was not given in its complete text in Boise because of the ten minute time limit. B.P.A. also should have been limited to ten minutes in their presentation as this meeting was publicized as a meeting to get imput from the people. 200 miles is a long way to travel for a ten minute presentation.

Sincerely,

John A. Pierce

John A. Pierce

JAP:aa

Telephone 503/440-4231
Room 305 , Courthouse
Roseburg, Oregon 97470

UMPQUA REGIONAL COUNCIL OF GOVERNMENTS

ACKNOWLEDGEMENT OF NOTIFICATION
for the
OMB CIRCULAR A-95 AREAWIDE CLEARINGHOUSE REVIEW

Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P. O. Box 3621-SJ
Portland, OR 97208

Notification Title : DEIS for1982 Rate Proposa

Reference Number:

Receipt Date: 5-6-82

This is being distributed to the following agencies or offices for review and comment: ____________________

/ / Your notification will be presented at the next meeting of the Umpqua Regional Council of Governments on ____________________ at 1:30 p.m., in Room 200 of the Douglas County Justice Building. If this meeting date is more than 30 days from areawide clearinghouse receipt, an extension of the review period is requested. The response to the notification, including formal action by the Council and documentation of all comments, will be mailed to you on ____________________.

For applicants that are not members of Umpqua Regional Council of Governments, a $35.00 filing fee will be requested for payment in the response mailing.

/ X / Your notification will not be reviewed formally by the Umpqua Regional Council of Governments. If you receive no response within 30 days of the date of areawide clearinghouse receipt, you may assume no adverse comments to the notification. There is no filing fee for this review.

Shannon Davis, Coordinator
Phone: 440-4237

OREG PROJECT NOTICE ACKNOWLEDG NT

State Clearinghouse
Intergovernmental Relations Division
155 Cottage Street N.E.
Salem, Oregon 97310

Phone (503) 378-3732 or Toll Free in Oregon 1-800-452-7813

Applicant: BPA

Project Title: 1982 Rate Proposal

Date Rcd. 5/11/82

PNRS # OR 820511-030-4

Your project notice has been assigned the file title and number that appear above. Please use it in correspondence and if applicable enter it in Block 3A on the 424 form for the project. Your project otice must also be submitted for review to any affected areawide clearinghouse.

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/_/ 30 day review of your final grant application began on the above date.

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c. DIRECT FEDERAL DEVELOPMENT

/_/ Initial 30 day review

d. ENVIRONMENTAL IMPACT STATEMENT

/X/ Initial 45 day review of draft EIS began on above date.

/_/ 30 day review of final EIS began on the above date

e. STATE PLAN/AMENDMENT

/_/ 45 day review began on above date.

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Your project notice was circulated to state agencies checked below

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X Soil & Water Division
_ Economic Development
_ Fire Marshal
_ Housing
_ Labor
_ Real Estate

EDUCATION
_ Education
_ Higher Education
_ Educ Coordinating

EXECUTIVE
_ Budget

HUMAN RESOURCES
_ Senior Services
_ Children's Services
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_ Corrections
_ Employment
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X Governor's Office
X DEQ
X Fish and Wildlife
X Forestry
X Geology
X Lands
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_ Director
_ Highway Division
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_ Public Transit
_ Aeronautics

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_ Extension Service
_ Health Plng & Dev. Agcy.
X LCDC
_ Law Enforcement
X Energy
X Historic Preservation
X Other PUC

MONTANA HISTORICAL SOCIETY

HISTORIC PRESERVATION OFFICE

225 NORTH ROBERTS STREET • (406) 449-4584 • HELENA, MONTANA 59601

May 12, 1982

Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, OR 97208

Dear Mr. Morrell:

Re: Draft Environmental Impact Statement
1982 Rate Proposal

The Montana State Historic Preservation Office has reviewed the above referenced document to ascertain the Department of Energy's compliance with Section 106 of the National Historic Preservation Act of 1966, as amended, and Executive Order 11593.

The section on Heritage Conservation omits the first mandated Federal agency responsibility -- "to identify or cause to be identified any National Register or eligible property that is located within the area of the undertaking's potential environmental impact." The identification of National Register and eligible properties <u>must</u> precede a finding of effect. In addition, a determination of effect is not made solely by the staff or a Federal agency. It is made in consultation with the State Historic Preservation Office and the Advisory Council on Hisotric Preservation. We refer you to the implementing regulations of the Historic Preservation Act of 1966, 36CFR800.

This document has expanded far beyond the weatherization measures proposed in the Environmental Assessment for the Proposed BPA Regionwide Weatherization Program published on April 30, 1981. The installation of storm doors and windows and the solar/heat pump water heater program will unquestionably have an effect on National Register or eligible properties as defined 36CFR800.3(a).

We are also concerned with the proposed conversion of interior and exterior "mercury vapor, incandescent and selected flourescent lamps to the more efficient high pressure sodium and metal halide." Lighting fixtures are an important architectural feature in many historic buildings and the ambience in many older neighborhoods is provided by the original street lighting fixtures. The potential effect is likely to be adverse in both instance.

We applaud the weatherization program in principle, for to preserve our older buildings, we must make them energy efficient. We should not, however, rush thoughtlessly in to a program which has the potential to adversely impact significant historic and architectural properties and neighborhoods without a careful evaluation of those properties and alternatives. We request that the Heritage Conservation section be expanded to outline your compliance with all historic preservation legislation.

Finally, addressing the larger issue of rate increases, there is an important impact which has not been discussed. That is the effect on the state's historic mansions. Once all feasible energy conservation methods have been undertaken, increased rates have the potential to place an unsolvable burden on historic house owners. The only option left for the owner will be conversion to multiple family dwellings. Although this is a solution of last resort, it is clearly looming before us today. We need to answer the question of what the effects will be and what options will be available.

Sincerely,

Marcella Sherfy

Marcella Sherfy
Deputy SHPO

LJ/det

cc: Marjorie Ingle
Advisory Council on Historic Preservation

United States
Department of
Agriculture

Soil
Conservation
Service

1220 S. W. Third Avenue
16th Floor
Portland, Oregon 97204

OFFICIAL FILE COPY
No. Date MAY 17 1982
Referred To:
Action Taken
☐ ANS. ☐ NO REPLY
By Date

May 13, 1982

Peter T. Johnson, Administrator
Bonneville Power Administration
P O Box 3621
Portland, Oregon 97208

Dear Mr. Johnson:

We have no comment on your 1982 Rate Proposal, Draft Environmental Impact Statement.

Sincerely,

Hillebrandt ACTING
JACK P. KANALZ
State Conservationist

BIG BEND *Electric* CO-OPERATIVE, INC.

RITZVILLE, WASHINGTON 99169

OFFICIAL FILE COPY

No. Date MAY 18 1982

Referred To:

Action Taken

☐ ANS. ☐ NO REPLY

By Date

May 14, 1982

Mr. Peter Johnson, Administrator
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

Re: Impact of proposed BPA rate increase on irrigated agriculture.

Dear Mr. Johnson:

In reviewing BPA's Draft Environmental Impact Statement for its 1982 rate proposal, I was bewildered when I came across the Irrigated Agriculture Study, "a re-examination and updated study" by Dr. Norman K. Whittlesey, WSU.

I was surprised to see BPA contracting with Dr. Whittlesey once again when his initial study in 1978 proved so controversial.

I was also surprised, although I suppose I should not have been, by Dr. Whittlesey's latest conclusions: "In general, the Whittlesey study concluded that there would be no changes in the short run in irrigated acreage as a result of BPA's proposed rate increase." Also, "...Whittlesey found again that, in the short run, changes in average income would be expected to be negligible (for irrigators)."

In reviewing present and future power costs, Dr. Whittlesey claims, "...it is estimated that between 1982 and 1985 the average cost of retail power to irrigated agriculture will increase by 14.8 percent in <u>nominal dollars</u>." Apparently Dr. Whittlesey isn't aware that BPA has proposed a 73 percent rate increase for October 1, 1982 which will require a 37 percent increase at the retail level for irrigators served by our Co-op. He should also be reminded of WPPSS 4 and 5 costs, which, for many utilities, will amount to retail rate increases of over 14.8 percent.

Dr. Whittlesey likes to talk about "nominal dollars." I'm not sure what his nominal dollars are, but I do know that irrigators in our area are receiving far fewer real dollars for their wheat

Electrifying

YOUR FARM AND HOME

today than they were 20 years ago, despite what the Whittlesey study might indicate. And the proposed BPA rate increase will not, as Whittlesey implies, be lightly felt by irrigators. It's going to be devastating for many people who have invested everything they own in irrigated operations.

I have enclosed a newspaper article from the local paper which, I am convinced, provides a truer picture of BPA rate increase impacts on irrigators than the Whittlesey studies, past and present. Hopefully you and your staff will give the irrigator's problems honest consideration.

Sincerely,

Byron Wagner

Byron Wagner
Manager

cjb
Enc.

Adams County irrigators were among the crowd attending a public meeting with Bonneville Power Administration officials in Spokane last week. Here Curtis Moeller addresses the BPA members while the audience, most of those pictured here are Big Bend Electric Co-op utility users, listens intently.

—Big Bend Electric Co-op photo

Irrigators to BPA: 'no more rate hikes'

Farmers can't absorb another huge electric rate increase.

That's the message Bonneville Power Administration personnel received from angry farmers, most of them irrigators, at BPA public rate hearings in Richland and Spokane the evenings of April 20 and 21. BPA has proposed a 73 percent price increase for the wholesale power it sells to public utilities, effective Oct. 1, 1982. The wholesale increase would mean a 37 percent increase at the retail level, an increase irrigators and other rate-payers say they can't cope with.

"If rates continue to escalate and commodity prices remain at or near present levels, it will only be a matter of time before irrigated agriculture will no longer be able to afford the electric power," said Ritzville farmer Gary Galbreath. "Only by considerable restraint in power rates can this be avoided."

Galbreath spoke before an audience of some 130 persons at the Spokane meeting, over 100 of them Adams and Lincoln county farmers. The Richland meeting, 24 hours earlier, had attracted several hundred construction workers about to lose their jobs due to BPA's decision to mothball Hanford N-plant number one. But at the Richland meeting, too, irrigators presented the most eye-opening evidence concerning the probable impact of BPA's proposed rate hike.

Most irrigators who attended the hearings are members of Big Bend Electric Co-op, which serves the rural areas of Adams and Franklin counties. The Co-op buys all of its wholesale power from BPA.

"BPA encouraged us to use more and more power during the 1960s and 70s," an Adams County farmer stated. "Now that we've spent half our lives and all our money converting our farms to irrigation, we are being priced out of business through higher and higher electric rates. My rates have increased nearly 300 percent in just the last three years. I can't take any more."

Gary Fuqua, director of BPA's rates division, presented BPA's rate proposal at both meetings. In Spokane he noted roughly half of the revenue BPA receives from public utilities and other priority firm rate customers goes toward nuclear plant costs, even though the three plants BPA is financing, WPPSS plants 1, 2 and 3, have yet to produce any power.

Also cited as reasons for needing more income were the exchange agreements with investor-owned companies and the cost of BPA conservation programs. Under the exchange the IOUs can sell power to BPA at their average system cost and purchase an equal amount of power back from BPA at lower rates. BPA's conservation budget runs into the hundreds of millions of dollars. Overall, BPA claims it will need $2.4 billion in revenue during fiscal year 1983, or about $700 million more than current rates would produce.

Many irrigators were upset with BPA's policy of selling power outside the region, mostly to California utilities, at rates considerably below those charged the region's public utilities. BPA sells excess power for as little as one-cent per kwh under spill conditions, about half the rate it proposes to charge public utilities starting Oct. 1, 1982.

Some 25 farmers presented oral testimony at the Spokane meeting and a like number had written testimony to enter into the record.

The first three speakers were Big Bend Co-op members Reid Phillips, Arnold Moeller and Larry Honn, all irrigators.

Phillips explained how his family is working to make their irrigation systems more energy efficient and called on BPA to assist in the effort.

Moeller encouraged BPA personnel to quit making graphs and charts just to explain why more money was needed, but to study history and learn from the charts and graphs to avoid more blunders in the future. He called for better fiscal management at BPA, from the administrator down through every employee.

Larry Honn, like a number of other irrigators who spoke after him, explained the financial details of his farming operation to point out how higher rates impact the irrigator. He questioned whether irrigated agriculture can remain a viable industry after the proposed rate increase is implemented, "if it still is."

The Spokane audience quizzed Fuqua in detail about BPA costs. Many were surprised to learn that electricity from hydroelectric dams still costs only three-tenths of a cent per kwh to produce. The October rate increase would bump BPA's wholesale rate for public utilities to about two cents per kwh.

But BPA still sells mainly hydroelectric power, so many people were quick to ask about the wide discrepancy. The answer, Fuqua explained, is primarily the non-producing nuclear plants. In addition to the power exchange and conservation, he also cited increased construction, operation and maintenance and administrative costs at BPA.

"BPA should look at what happened to the Chrysler Corporation and learn from its mistakes," Jerry Snyder, another Big Bend member, stated. "We can't continue to pay for BPA's mistakes."

A Spokane housewife joined the irrigators in their argument against further huge, unmanageable rate hikes. "If the farmer goes out of business, we're all going to suffer," she said. "It isn't hard to figure out what food costs will do when shortages occur. The farmer is concerned about whether he can afford to grow the food. I'm concerned about being able to buy food for my family. These high rates will hurt all of us, in more ways than one."

At the Richland meeting some people with low incomes provided testimony to illustrate the plight higher electric rates means for them.

Over 30 members of Big Bend Electric went to the Richland meeting, although some were among the 500 who couldn't get into the packed meeting room. Some 300 people managed to squeeze into the 200-seat meeting room in the Federal building in Richland. About 35 Big Bend members attended the Spokane meeting.

"Tie rate increases to commodity prices," one farmer argued. Others asked BPA to restructure its rates to lower the demand rate charged during summer irrigation months, or to allow irrigators a discount, as was the case during the 60s and early 70s when BPA promoted energy use by farmers.

"The Federal government could buy WPPSS bonds at a discount and pay for them with a general tax," said Les Snyder, another irrigator ser[illegible] by Big Bend Co-op. He explained that millions in WPPSS bonds were sold in years past at low interest rates and could be purchased at less than half their face value today. "Something has to be done or the irrigation industry will die."

A number of farmers stated they were seriously considering reverting back to dryland farming. But those with large investments in irrigation equipment admitted that the switch would pose additional problems.

"Most of us can't meet our irrigation debts through dryland farming," a Lincoln County farmer explained. "We're in trouble either way."

The farmer's inability to control commodity prices was often noted. "When the big aluminum plants pay more for electricity they just up the price on the next ingot that rolls off the production line," one farmer said. "We can't do that. We can absorb just so much — then we are forced out of business. That's about the place many of us are today."

Fuqua was asked if BPA had considered how far off its income projections might be if the proposed rates forced a significant number of irrigators out of business. Widespread unemployment in the agriculture sector would impact other industry and government, too, due to lost tax revenues.

The point was made that BPA might ultimately end up better off with a lower rate increase that ratepayers could manage as opposed to the 73 percent proposal that may force agriculture and other industries out of business, and residential users to use less power.

"I think we're looking at a vicious cycle starting here that's going to have enormous consequences that BPA isn't even considering," Curtis Moeller of Ritzville said. "It's obvious that BPA has been wrong on most of its predictions in the past. But I don't think any of us can afford to allow BPA to blunder again.

"It's our fault if we continue to allow this to happen," Moeller continued. "But I think everyone has had enough. Go back and tell the BPA administrator that ratepayers have had all they're going to take."

The 73 percent increase would be BPA's third large rate increase in recent years. In December, 1979, the rate increased 88 percent. In July, 1981, aother 59 percent was added. The proposal to hike rates another 73 percent in October would mean wholesale rates, compounded, would have increased nearly 500 percent in a period of just 34 months.

The rapid fire increases are a sore point with irrigators. Many said they expected higher rates but wanted them spread out over a longer time period so they would be easier to absorb.

The Richland meeting ended shortly after 11 p.m. when the tired stenographer couldn't continue. The Spokane meeting ended at 10:30 p.m. following Curtis Moeller's testimony. But if the irrigators and other ratepayers who spoke at the two meetings are even partly correct in their estimates of what lies ahead, the dialogue between ratepayers of the region and BPA is far from over.

"If things don't improve, the ratepayers will come in en masse to BPA's big Portland office building and let the administrator hear first hand how we feel," C. Moeller said. "I hope he gets the message: No more. No more."

COLUMBIA RURAL ELECTRIC ASSOCIATION INC.

"OWNED BY THOSE IT SERVES"

115 EAST MAIN STREET
P.O. BOX 46
DAYTON, WASHINGTON 99328
TELEPHONE (509) 382-[illegible]

OFFICIAL FILE COPY
No. Date MAY 20 1982
Taken
ANS. NO REPLY
By Date

May 17, 1982

Peter Johnson, Administrator
Bonneville Power Administration
PO Box 3621
Portland, OR 97208

Dear Mr. Johnson,

After reviewing BPA's Draft Environmental Impact Statement for the 1982 Rate Proposal, I was amazed to find that BPA had used Dr Whittlesey, WSU, to make the re-examination and update. Dr Whittlesey's 1978 Study and 1979 Supplement proved so very controversial that their value must be questioned.

In the 1982 update Dr Whittlesey used "Nominal Dollars" and "Real Cost" repeatedly. He should consider "Actual Dollars" for they are what the farmer has to spend.

On Page VII-18, Line 6, the report states a retail rate increase of 28.7%; our actual rate went from 1.01¢/KWH in '79 to 2.21¢/KWH in '81 - that is a 118.8% increase. We are projecting a 33% increase for the 1981-82 period versus the report's 19.4%. We project a rate increase for the '82 to '85 period of 59.9% versus the report's 14.8%. Dr Whittlesey's numbers just don't compare with those for utilities that are facing the 73% BPA rate increase this fall and WPPSS 4/5 payments the first of '83.

As the irrigators have tried to tell BPA at the Rate Hearings (including the Richland fiasco), they cannot absorb these large rate increases with the static farm prices they are receiving. We ask that you and your staff carefully analyze the irrigators input at the rate hearing and not depend on the questionable Whittlesey Report to make your final determination of a rate for the irrigator.

Very truly yours,

COLUMBIA RURAL ELECTRIC ASSN. INC.

Clark A. Brewington

Clark A. Brewington, Manager

CAB:vb

ACKNOWLEDGEMENT

State of California
Project Notification and Review System
Office of the Governor
(916) 445-0613

PROJECT: Rate Proposal/1982

State Clearinghouse Number (SCH) 82051909

Please use the State Clearinghouse Number on future correspondence with this office and with agencies approving or reviewing your project.

Date Review Sta ts: 5/19
(Review starts on following date when document is received after 10 a.m.)

Date Review Period Ends: 6/24

This card does not verify compliance with environmental document review requirements. A letter containing the State's comments or a letter confirming no State comments will be forwarded to you after the review is complete.

F' ıse contact Daniel Conaty at the Clearinghouse if you c .ıot receive the letter within a reasonable time after the review ends.

Rev. 10/81

JOHN SPELLMAN
Governor

JACOB THOMAS
Director

STATE OF WASHINGTON

OFFICE OF ARCHAEOLOGY AND HISTORIC PRESERVATION

111 West Twenty-First Avenue, KL-11 • Olympia, Washington 98504 • (206) 753-4011

May 21, 1982

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, OR 97208

Log Reference: 314-F-BPA-01

Re: 1982 Rate Proposal DEIS

Dear Mr. Morrell:

A staff review has been completed of your draft environmental impact statement. We will reserve our comments until such time as specific actions are proposed which may affect the cultural environment. Please note that on Page V-119 your reference to the National Historic Preservation Act (NHPA) of 1966, as amended, Section 6, should refer to NHPA, Section 106.

Thank you for this opportunity to comment.

Sincerely

Robert G. Whitlam, Ph.D.
Archaeologist

JOHN SPELLMAN
Governor

JAN TVETEN
Director

STATE OF WASHINGTON
WASHINGTON STATE PARKS AND RECREATION COMMISSION
7150 Cleanwater Lane, KY-11 • Olympia, Washington 98504 • (206) 753-5755

May 21, 1982

35-2650-1820
DEIS - 1982 Rate Proposal
(E-2364)

Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, OR 97208

Dear Mr. Morrell:

The staff of the Washington State Parks and Recreation Commission has reviewed the above-noted document and does not wish to make any comment.

Thank you for the opportunity to review and comment.

Sincerely,

David W. Heiser, E.P., Chief
Environmental Coordination

DWH/sh

cc: Barbara Ritchie, Department of Ecology

Bowler, Bruce

BRUCE BOWLER
LAWYER
244 SONNA BUILDING
BOISE, IDAHO 83702
PHONE 343-6072

May 19, 1982

DIVISION OF POWER MANAGEMENT
No. R-82-225 Date 5/24
Referred to:
Action Taken:
☐ Ans. ☐ No Reply
by Date

Donna L. Geiger
Public Involvement Coordinator
Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

Re: 1982 Wholesale Power Rate Hearings
PBB

Dear Ms. Geiger:

Thank you for your letter of May 10, 1982, summarizing activity on wholesale power rate hearings.

I was not able to attend the Boise Hearing but do not fit your characterization that participants generally called for less conservation and lower electrical costs for irrigators. Quite the contrary, this voice from Idaho would call for more conservation and less subsidized electrical costs for irrigators. Our neglect of environmental quality has for too long been subsidizing low cost hydroelectric energy.

Increasing power costs is the best leverage for accomplishing the conservation objective of the Northwest Power Act. Idaho irrigators have been notoriously wasteful in their utilization of low cost power for high pumping lifts for agriculture industry with many negative impacts on our natural resources. Idaho agriculture industry should not be permitted to intimidate needed power rate increases to accomplish the objectives of a general welfare balance mandated by the Northwest Power Act that includes enhancement of the anadromous fisheries.

Tilting toward cheaper power for irrigators would be the wrong way to go.

Thank you kindly.

Very truly yours,

Bruce Bowler

Bruce Bowler

BB/kmk

COMMENTS

OF THE NATURAL RESOURCES DEFENSE COUNCIL, INC.

ON THE BONNEVILLE POWER ADMINISTRATION'S

DRAFT ENVIRONMENTAL IMPACT STATEMENT:

"1982 BPA Wholesale Rate Increase"

--June 10, 1982--

I. Introduction

These comments are submitted by the Natural Resources Defense Council in response to a Draft Environmental Impact Statement entitled "1982 BPA Wholesale Rate Increase" (hereinafter "1982 Rate Proposal DEIS). We have concluded that the DEIS fails to comply with the mandates of the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. 4321 et seq. Revisions and resubmission for public comment are necessary to remedy the deficiencies of the document. We enumerate, in the sections that follow, a number of specific inadequacies of the 1982 Rate Proposal DEIS.

II. The Analysis of Alternatives is Totally Inadequate

An EIS must contain a detailed analysis of the environmental impacts of "alternatives to the proposed action." NEPA, 42 U.S.C. § 4332(2)(C)(iii). The importance of this requirement has been recognized by the courts and CEQ as well as Congress. The CEQ Regulations, for example, refer to the alternatives section as "the heart of the environmental impact statement." § 1502.14. Those regulations require that agencies "shall":

> "(a) Rigorously explore and objectively evaluate all reasonable alternatives, and for alternatives which were eliminated from detailed study, briefly discuss the reasons for their having been eliminated." § 1502.14(a)(emphasis supplied).

The consideration and discussion of alternatives has been justly termed the "linchpin of the entire impact statement." Monroe County Conservation Council, Inc. v. Volpe, 472 F. 2d 693, 697-98 (2nd Cir. 1972). The alternatives requirement has two fundamental objectives: (1) to force agencies to consider all reasonable approaches to an action, see, e.g., NRDC v. Morton, 458 F. 2nd 827, 836 (D.C. Cir. 1972); and (2) to inform the public what those approaches are, in order that they may comment upon them. See, e.g., California v. Bergland, 483 F. Supp. 465 (E.D. Ca., 1980). "Only in this fashion is it likely that the most intelligent, optimally beneficial decision will ultimately be made." Calvert Cliffs' Coordinating Comm., Inc. v. AEC, 449 F. 2d 1109, 1114 (D.C. Cir. 1971). See also CEQ Regulations § 1500.0(c).

In order to fulfill these objectives, agencies are under an affirmative obligation to seek out and explore the wisdom of alternative courses of action. See Rankin v. Coleman, 394 F. Supp.

647, 658 (E.D. N.C. 1975).* The EIS must examine all obvious and logical alternatives. Brooks v. Coleman, 518 F. 2d 17 (9th Cir. 1975). It must discuss a range of reasonable alternatives. See, e.g., California v. Bergland, supra; Movement Against Destruction v. Volpe, 361 F. Supp. 1360, 1388 (D.C. Md. 1973); CEQ Regulations, § 1502.2(e). Cf. Greene County Planning Board v. F.P.C., 559 F. 2d 1227, 1232 (2d Cir. 1976) ("The purposes of NEPA are frustrated when considerations of alternatives and collateral effect are reasonably constricted."). Agencies must justify the range of alternatives considered and explain why it is believed to be reasonable. California v. Bergland, supra, at 488. Finally, the CEQ regulations require specific attention to the "conservation potential of various alternatives." 43 Fed. Reg. 55978, 55996 (1978). These nondiscretionary responsibilities have not been discharged in the 1982 Rate Proposal EIS.

Moreover, BPA may not properly remedy the deficiencies identified below in the current DEIS by simply incorporating additional analysis in the final EIS. To do so would deny the public and

*That Congress attached particular importance to agency consideration of alternatives is demonstrated by NEPA itself. A thorough analysis of alternatives to recommended courses of action is required not only when the preparation of an EIS is undertaken pursuant to § 102(2)(C), but also whenever a proposal "involves unresolved conflicts concerning alternative uses of available resources." 42 U.S.C. § 4332(2)(E). This section expressly demands that agencies "study, develop and describe" all appropriate alternatives to proposed actions even apart from the EIS process. The § 102(2)(E) duty to consider alternative courses of action has consistently been viewed by the courts as being "independent of and of wider scope than" the duty under § 102(2)(C) to file an EIS. NRDC v. Callaway, 524 F. 2d 79, 93 (2d Cir. 1975); Trinity Episcopal School Corp. v. Romney, 523 F. 2d 88, 93 (2d Cir. 1975); Nucleus of Chicago Homeowners Association v. Lynn, 524 F. 2d 225 (7th Cir. 1975).

concerned governmental agencies the right to comment on critical issues in BPA's environmental review. Instead, BPA must, at the very least, issue a revised DEIS (or relevant portions thereof) and circulate it for public comment. *See, e.g.*, *NRDC* v. *Hughes*, 437 F. Supp. 981, 990-991 (D.D.C. 1977); Regulations of Council on Environmental Quality, 40 C.F.R. § 1502.9(a) (revised draft required "if the draft statement is so inadequate as to preclude meaningful analysis"); and *id.*, § 1502.9(c)(1)(ii) (Agencies must prepare, circulate and revise supplements to draft statements if "[t]here are significant new circumstances, or information relevant to environmental concerns and bearing on the proposed action or its impacts.")

A. The DEIS Does Not Adequately Address the Issue of a Tiered Rate Structure

The limited discussion in the DEIS of the tiered rate structure is vague, inadequate, and confusing. From it the reader cannot possible gain an understanding of any solid or coherent rationale for BPA's decision to reject a tiered rate structure.

The discussion is vague in that, while listing several alternative reasons why tiered rates might create problems, it nowhere specifies which, if any, are actually considered likely to result in such problems. VII-63 and VII-64. For example, the DEIS nowhere addresses what has been the historical experience with wholesale tiered rates employed by other agencies, such as the Power Authority of the State of New York. The discussion, aside from the statement that tiered rates would be "complex to administer" (VII-64) consists solely of speculation.

The discussion of tiered rates is inadequate because BPA does not even bother to analyze, if only for evaluative purposes, a sample tiered rate structure. There is not a single alternative tiered rate structure evaluated in the DEIS. This in spite of BPA's own statement, in the concluding paragraph of the Executive Summary portion of the DEIS, that "[o]ne of the major rate design issues raised concerned the implementation of tiered rates." II-16. In light of this statement, BPA should at least have discussed and evaluated sample tiered rate structures in the DEIS section entitled "Study of Alternative Rate Designs and Impacts," if not actually addressed a tiered rate structure as one of its five programmic alternatives.

What BPA presents instead are evaluations based on abstract and unspecified "worst-possible" case scenarios. Rather than identify and evaluate carefully designed tiered rate structures, BPA states:

> The effectiveness of this (price) signal is very dependent on the design specification of the block components of the rate. For example, if a consumer's total consumption is below the top tier, and if the base tier price is lower than the rate which would be employed in the absence of tierings, the effect could be an increase in the consumption by that consumer. VII-63.

The remedy to such a problem is careful design of the block components. For example, in pricing electricity dedicated to customers' residential loads, BPA could limit base tiers to totals reflecting post-conservation needs of all households in the customer's service territory. Ignoring this possibility, the DEIS continues:

> Furthermore, because of the time lags between the signal provided under a wholesale tiered rate and the ultimate consumer's decision to use or conserve electricity, it may be difficult to design an appropriate wholesale rate that would elicit the desired response from the retail consumer. VII-63.

What the estimated time lag might be is not indicated, but there is no reason why it should be more than the number of weeks or months it takes for the BPA customers to respond to the clear price signals that can be provided in a properly designed tiered rate structure. Again, BPA does not address a specific tiered rate structure and comment upon it, but merely continues:

> This is of concern particularly because there is no assurance that the objective of the wholesale tiered rate design will be reflected in the retail rate design. VII-63 and VII-64.

But utilities would have nothing to gain, and much to lose, by refusing to tier their retail rates in the aftermath of Bonneville action. Furthermore, the efficacy of a tiered rate structure for wholesale customers does not rest on whether it will be reflected in retail rate designs. Even if utilities did not adopt tiered rates at the retail level, they would have strong incentives to increase their own investment in cost-effective alternatives to the high-priced block of electricity, such as conservation, renewable energy resources, and cogeneration. To assume, as BPA apparently does, that none of these responses are likely is to deny that utilities respond to price signals -- which BPA surely does not believe.

The discussion of tiered rates is confusing in that BPA assumes contradictory postures in different sections of the report with respect to this issue. Although BPA generally speaks disapprovingly of tiered rates (see II-10, II-16, VII-62, VII-63, and VII-64), in the one other section of the report where the issue is addressed, BPA's discussion is entirely positive (see V-77, V-78, and V-79). The reader's confusion is exacerbated because, although BPA clearly recounts in the DEIS two of the arguments offered by tiered rate proponents, no counterarguments are included to aid the reader in understanding and evaluating BPA's rationale for rejecting the proponents' arguments. Moreover, the fact that the arguments of the tiered rate proponents presented in the DEIS are relatively lucid compared to the reasons offered by BPA for rejecting the concept only further confuses the reader.

The treatment of the tiered rate issue with respect to billing credits is also confusing. In the Executive Summary portion of the DEIS, BPA cites, as a reason for the exclusion of tiered rates, the potential that such rates may serve a function already addressed by BPA's billing credits program. II-10. However, this argument is not explained more fully anywhere in the body of the report. Thus, when addressing its reasons for rejecting a tiered rate structure, BPA makes no reference to billing credits. See VII-63 and VII-64. Conversely, when addressing the billing credits program, BPA makes no reference to the arguments of tiered-rate proponents. See VII-74 and VII-75. The result is confusion over whether BPA is actually relying on the argument that billing credits may be an effective substitute for tiered rates.

NRDC has addressed the fact that the proposed billing credits program is no substitute for a tiered rate structure. See NRDC, "Comments on BPA's Notice of Proposed Wholesale Power Rate Adjustment" (April 23, 1982). BPA has made no commitment to offer adequate billing credits; indeed, the agency has made no provision for any credits in its revenue projections. The proposed BPA regulations on billing credits ensure that they will be held at artificially low levels for years to come. See 47 Fed. Reg. 9760, 9779 (1982)(billing credits are to be set by reference to the average cost of resources actually used to meet load growth in the year of the award, not the cost of new resources displaced by qualifying measures). Until and unless these defiencies are remedied, billing credits are no substitute for tiered rates. See NRDC, "A Fundamental Flaw in the BPA Proposal" (March 15, 1982) (distributed by BPA at Public Information Forums on Billing Credits).

B. <u>The DEIS Omits Any Discussion of the Wholesale Percentage Rate Discount for Low-System-Density Utilities</u>

There can be no doubt that BPA's proposal to continue the low-density discount has significant environmental consequences. Although not so intended when established, the low-density discount has actually worked as an incentive for additional energy consumption. Qualifying rural utilities receive a uniform percentage discount, regardless of consumption; as a result, the current policy provides a larger dollar discount to customers using relatively large quantities of electricity. Meanwhile, these utilities have set high monthly service charges, while accurately reflecting discounted energy and demand charges in consumers' rates. The result is functionally indistinguishable from a "declining block" retail rate structure, which rewards increased consumption with lower costs per kilowatt-hour.

NRDC has urged that the percentage low-density discount be withdrawn and a per-customer discount substituted for it, so as to eliminate rewards for electricity waste while still providing rate relief to rural utilities with high distribution costs. BPA cannot fail to address the low-density discount issue without violating the explicit language of NEPA. 42 U.S.C. § 4332(2)(c).

C. <u>The DEIS Omits Any Discussion of BPA's Proposed Refusal to Recover the Full Costs of Its Conservation Programs Through BPA Rates</u>

BPA's effort to recover a portion of the costs of its conservation programs through direct charges to participating utilities has significant environmental consequences. It threatens to frustrate commendable efforts by BPA staff to secure maximum possible utility participation in the agency's conservation programs. If part of the cost of implementing a BPA program must be paid as a fee by the participant, nonparticipants are correspondingly rewarded. In essence, these direct charges, which BPA elsewhere has proposed to initiate (47 <u>Fed. Reg.</u> 13710, 13731 (March 31, 1982)), impose an additional barrier to utility involvement in regional conservation efforts. In order to comply with NEPA, BPA must address this issue in the EIS, explaining the reasons for its actions and analyzing environmentally preferable alternatives.

D. <u>The DEIS Omits Any Discussion of the Environmental Consequences of Eliminating Demand Charges</u>

While the DEIS addresses diurnal differentiation of demand charges (V-82), it ignores issues surrounding <u>retention</u> of demand charges. Eliminating such charges, and imposing offsetting increases in energy rates, offers significant environmental benefits in the Northwest's mixed hydro-thermal system. NRDC endorses the analysis of the environmental effects of demand charges presented by economist James Lazar in hearings preceding

BPA's 1981 wholesale rate increase. (Public Field Hearing Regarding Transmission and Wholesale Power Rate Adjustment, Seattle, Washington, March 12, 1981.) BPA's NEPA obligations will not countenance continued failure to consider alternatives to retention of demand charges.

III. Conclusion

It is incumbent upon BPA to revise and resubmit its 1982 Rate Proposal DEIS, or at least the portions addressed in the above comments, in order to comply with NEPA. The discussion of tiered rates is totally inadequate and abstract, and unnecessarily limited to speculation that is based on worst-possible case scenarios. The omissions of any discussion of the environmental consequences of the wholesale percentage rate discount for low-system-density utilities, as well as of BPA's proposal to recover less than the full costs of its conservation programs through BPA rates, must also be corrected. Finally, BPA must revise the DEIS to address the environmental issues surrounding the retention of demand charges. All of these revisions should be issued in a revised DEIS, and circulated for public comment.

Natural Resources Defense Council, Inc.
25 Kearny Street
San Francisco, CA 94108

DEPARTMENT OF HEALTH & HUMAN SERVICES

Public Health Service
Bldg. E, Rm. 511

Centers for Disease Control
Atlanta, Georgia 30333
(404) 262-6649

June 21, 1982

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P. O. Box 3621-SJ
Portland, Oregon 97208

Dear Mr. Morrell:

We have reviewed the Draft Environmental Impact Statement (EIS) for Bonneville Power Administration's (BPA's) 1982 Rates Proposal. We are responding on behalf of the U.S. Public Health Service and are offering the following comments for your consideration in preparing the final document.

The effect that increased power rates will have on home conversion to burning wood for home heating should be better addressed. Since wood burning is becoming a rapidly growing source of air pollution in the Pacific Northwest, effects upon ambient air quality from uncontrolled emissions of wood burning should be carefully considered.

We understand that the proposed action and alternative actions will have different effects upon agriculture dependent upon irrigation. With the proposed BPA alternative, about 23,000 acres of "existing irrigated acreage" will be withdrawn. However, under the long-run incremental cost alternative, the "existing irrigated acreage would be 19 percent or 779,000 acres less." These effects upon irrigation farming could also have some impact upon vector control and prevention efforts.

While "environmental benefits could result from lower levels of water withdrawals, reduced siltation and lower amounts of pesticides used" from reduced irrigation farming, the Final EIS should state the positive or negative effects that reduced farming and maintenance of irrigation drainage facilities will have on vector control efforts in the area. Abundant mosquito populations can be produced in irrigated fields or irrigation ditches and can cause serious health and nuisance problems. Local public health authorities may be able to provide a history of vector-borne disease and nuisance problems that exist in the project area.

We appreciate the opportunity to review the Draft EIS. Please send us one copy of the Final EIS when it becomes available. Should you have any questions about our comments, please call Mr. Robert Kay of my staff at FTS 236-6649.

Sincerely yours,

Chester L. Foster, Jr.

for Frank S. Lisella, Ph.D.
Chief, Environmental Affairs Group
Environmental Health Services Division
Center for Environmental Health

JOHN SPELLMAN
Governor

DONALD W. MOOS
Director

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
Mail Stop PV-11 • Olympia, Washington 98504 • (206) 459-6000

June 22, 1982

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, Oregon 97208

Dear Mr. Morrell:

Thank you for the opportunity to review the draft environmental impact statement for the 1982 Rate Proposal. We coordinated the review of this document with all of the state agencies and no comments were received. Therefore, the State of Washington has no objection to this proposal.

If you have any questions, please call me at (206) 459-6016.

Sincerely,

Greg Sorlie

Greg Sorlie
Environmental Review Section

GS:lc

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

JUN 21 1982

ER-82/853

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, Oregon 97208

Dear Mr. Morrell:

Thank you for your letter of April 30, 1982, which transmitted copies of the draft environmental statement for 1982 Rate Proposal for Period Through 1985.

Page II-9 - - Executive Summary states that there would be about 762,000 more acres under irrigation by the year 2000 under the LRIC alternative than under the no action alternative. This should probably be 762,000 acres less rather than more.

Footnote C of Table V-I is somewhat confusing. It indicates fiscal year 1983 repayment requirement was reduced by excluding irrigation assistance. The first irrigation assistance is not due until 1997. It is not clear how the irrigation assistance impacts the repayment requirement for 1983.

We hope these comments will be helpful to you.

Sincerely,

Bruce Blanchard
Director

DIRECT SERVICE INDUSTRIES, INC.

Formerly,

INDUSTRIAL CUSTOMERS

of Bonneville Power Administration

1201 Lloyd Center Tower • 825 N.E. Multnomah Street
Portland, Oregon 97232
Telephone (503) 233-4445 • Telecopy (503) 233-2618

June 23, 1982

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P. O. Box 3621-SJ
Portland, OR 97208

Dear Mr. Morrell:

We offer the following comments on Bonneville's Draft Environmental Impact Statement relative to its 1982 rate proposal:

Page IV-4. The first paragraph should recognize that if the Federal Base System resource pool is larger than the sum of the preference customer, federal agency and residential exchange loads, the excess would be used to supply DSI loads.

Page IV-9. The first partial paragraph discusses BPA's 1979 and 1981 rate increase to preference customers. We believe the cumulative effects of the 1979/81 rate increases have been at least as severe on DSI operations. These should also be listed and discussed.

Page V-2. Same comment as on page IV-9.

Page V-3, line 20. The $1.619 billion is given as $1.709 billion on page IV-6.

Page V-7, line 26. The $821 million is given as $731 million on page IV-6.

Page V-101, line 8. Lists the present energy reserve credit as 2.3 mills per kilowatt hour. This credit is 2.1 mills.

Page V-102. The paragraph beginning on line 18 discusses DSI reserve credits. The last two sentences state, "If not restricted, the resulting purchase power costs incurred by BPA would be directly assigned to the DSI bill. However, because the estimated purchases were so small, a purchase before restriction clause was not included in the IP-2 rate schedule."

Comment

Billing the DSIs for the cost of power BPA purchases in lieu of restrictions would be contrary to the intent and effect of the Regional Act:

> (a) The Senate report, Appendix B at page 59, provides in part "...in actual operation, DSI power withdrawn or curtailed in excess of interruptions for critical streamflows would be replaced by power purchased by BPA on a short term basis, if available."
>
> (b) Section 9(i)(1)(A)(ii) of the Act, the parenthetical phrase, by definition refers only to restrictions "in excess of interruptions for critical streamflows" since BPA then and only then has no replacement obligation.

The Administrator's Record of Decision dated June 1981 in the 1981 Wholesale Power Rate Proposal recognized BPA's obligation to purchase in lieu of restricting service to the DSIs. In the second and third paragraphs at page VI-14 he states:

> Another suggestion regarding assignment of purchase power costs was that BPA should restrict DSI second quartile loads before purchasing power to meet priority firm loads. The cost of any purchase made to serve the DSI second quartile then should be assignable to the DSIs.
>
> I disagree with the suggested use of the second quartile restriction rights. The purpose of a reserve is to serve as a resource of last resort. The value of the reserve is the right to restrict. Once the restriction is exercised its value as a reserve is lost and must be re-established as quickly as possible. The reserve is intended to function not as an economical alternative to other resources, but as a final backup that can be relied on to protect the quality of firm service. Furthermore, as included in the BPA and DSI briefs, in this case, Congress intended firm service to the DSI loads, subject only to restriction upon limited conditions. To plan to forego purchases to serve the DSI second quartile would be to fail to provide firm service. In this particular rate year the DSI load will be restricted in the event we cannot acquire sufficient resources. This is consistent with shaping of FELCC to support firm loads and uniforming the risks over the critical period. Furthermore, I believe BPA has a clear obligation to

acquire adequate resources to meet its firm loads which clearly includes three quartiles of the DSI load."

The above referenced paragraph in the DEIS should be changed accordingly.

Page V-104. First full paragraph notes that use of non-firm energy to serve top quartile loads "...could perhaps result in displacement of fewer firm thermal resources and therefore could be contrary to BPA's obligation to keep overall rates as low as possible consistent with sound business principles."

Comment

The DSIs believe BPA's proposal to provide top quartile service before displacing high cost resources accords with the intent and requirements of the Regional Act. The Act directs BPA to operate its system to serve the top quartile as a firm load. With critical period streamflow conditions and balanced loads and resources, all firm resources and all costs thereof would be allocated to serve firm loads. Under those conditions there would be no net service to the DSI top quartile.

The only resources available to BPA with which it can serve top quartile loads under balanced loads and resource conditions is generation from streamflows in excess of critical period flows. Since these streamflows provide service to the top quartile, the costs assigned to these resources are the appropriate costs to be charged to top quartile service. It is not appropriate to assign to the top quartile costs of resources that were developed to serve firm loads. BPA does not develop firm resources to serve the top quartile and costs of those resources should not be allocated to top quartile service.

Contrary to the implication of the paragraph in the DEIS, BPA's policy of serving the top quartile with nonfirm power prior to displacing resources minimizes the costs and environmental impacts of BPA's resources. The DSI top quartile is a firm load, just like other firm loads in the region, except that BPA has no obligation to develop firm resources to guarantee service. In the absence of its rights to restrict the top quartile, BPA would have to develop additional firm resources to provide service on a firm basis. This would increase BPA's total costs and pose the environmental impacts associated with approximately 1000 MW of additional new generating resources.

BPA can, of course, reduce its costs somewhat by not serving the DSI top quartile and using that power instead to displace firm resources developed to serve other customers. Similarly, it would be less expensive not to serve a firm utility load and to use that power to serve the load growth of other customers. Displacement of thermal resources prior to serving the top quartile would simply reflect a decision not to serve a portion of the DSI load that is dependent on power in excess of critical planning amounts for service; it does not reflect the least cost way of serving BPA's total load. The paragraph should be deleted or revised.

Page V-104. The first three lines of the second full paragraph should be revised to read as follows: "A third method of serving the top quartile also involves advancing energy from a later period into an earlier period. As with shifting of FELCC, the success of advancing energy is dependent upon streamflow..."

Page V-106. The second full paragraph suggests an alternative "...would be to eliminate any compensation to the DSIs associated with the restriction rights."

Comment

This would violate section 7(c)(3) of the Regional Act which requires that rates charged the DSIs reflect the value of reserves that they provide. The sentence should be removed.

Page V-107. The paragraph beginning on line 19 and the first paragraph on page V-108 suggest tiered rates could be developed to provide a different rate for the top quartile than for the bottom three quartiles.

Comment

The concept of a unified class of Industrial Firm Power for the DSIs existed through out negotiations leading to passage of the Regional Act and is evidenced in the Act:

(a) Section 7(c)(1)(A) of the Regional Act does not authorize a split rate. The phrase "rate or rates" occurs in all the rate directives but only for Section 7(f) is there legislative history to indicate that more than one rate at one time is contemplated. "Rate or rates" simply prevented any argument that BPA could not change its rates during any given period of years, notwithstanding that rate adjustments as infrequently as once as every five years were contemplated in the legislative history (see Senate Report, Appendix B).

(b) The Regional Act and its legislative history is quite clear on two points:

First, BPA was to calculate the DSI obligation for firm power costs based on three quartiles and then spread that cost and top quartile costs prospectively across all projected DSI power deliveries for the rate period to produce a single and uniform DSI rate (see Section 7(c)(1)(A), Senate Report, Appendix B at page 67 Footnote to line 62).

Second, in response to a question from Representative Dingell, specifically on this point, BPA assured Congress that it would charge a single DSI rate for all four quartiles of DSI load (See BPA reply dated October 18, 1979 to Question 11)

(c) Finally, and by way of emphasizing the intent of the Regional Act, Industrial Firm Power is defined in the DSI Power Sales Contract as a unified class of power that covers the full DSI load. (See Section 14 of the DSI Contract.) This definition of Industrial Firm Power carries forth concepts initiated in 1975 when BPA first established Industrial Firm Power as a class of service to the DSIs.

Page V-108, Subsection D. Add a sentence somewhat as follows: "The greater curtailments would cause socioeconomic impacts of higher unemployment and loss of other revenues associated with DSI operations." BPA perhaps should add data on DSI employment and economic benefit to the region.

Page V-111, line 11. Remove the word "industrial." All ratepayers likely would be impacted.

Page VI-13. Beginning at line 6 the statement is made, "...have eliminated salmonoid spawning except in the reach from Lake Wallula to Priest Rapids Dam (the Hanford reach)." Is there no spawning in the Rocky Reach and Wells pools and rivers/streams tributary thereto?

General

As discussed in our scoping conference, we believe a thorough discussion in the Environmental Impact Statement of adequate rates for export power, the impacts of such rate on the development of resources both in the Pacific Northwest and in the Pacific Southwest, and the environmental, social, and economic aspects of the alternatives would be very appropriate. Perhaps there has not been sufficient analysis of the resource alternatives to appropriately develop this scenario, but the adequacy of rates for the export market could be a substantial element of any such overall analysis.

We appreciate the opportunity to review the Draft Environmental Impact Statement and provide you with these comments.

Sincerely yours,

Brett Wilcox

Brett Wilcox
Executive Director

HD:BW:pl
PEL007:B

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION, CORPS OF ENGINEERS
P.O. BOX 2870
PORTLAND, OREGON 97208

NPDPL-ER

24 June 1982

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P. O. Box 3621-SJ
Portland, Oregon 97208

Dear Mr. Morrell:

This is in response to the Administrator's letter of 30 April 1982, requesting our review of your Draft Environmental Impact Statement for Proposed 1982 Wholesale Rate Proposal.

We have reviewed the subject statement and find that it doesn't impact any of our missions or responsibilities and, therefore, we have no comment.

We appreciate the opportunity to review and comment on the Draft EIS.

Sincerely,

Robert L. Henny

ROBERT L. HENNY
Acting ~~Assistant~~ Chief, Planning Division

June 25, 1982

COLUMBIA RIVER INTER-TRIBAL FISH COMMISSION

8383 N.E. Sandy Blvd.
Suite 320
Portland, Oregon 97220
Telephone (503)
257-0181

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, Oregon 97208

Dear Mr. Morrell:

The Columbia River Inter-Tribal Fish Commission offers the following comments on the draft environmental impact statement (DEIS) of the Bonneville Power Administration's 1982 Rate Proposal. As Bonneville begins its implementation of the Regional Power and Conservation Act, P.L. 96-501, proceedings like the 1982 rate adjustments will be key to carrying out the mandates that Congress prescribed in this legislation. As you should be aware, section 4(h) of the Regional Act contains detailed provisions concerning the protection, mitigation, and enhancement of fish and wildlife of the Columbia River and its tributaries. Unfortunately, it appears that with respect to the 1982 Rate DEIS, Bonneville has not addressed the affirmative obligations imposed by the Act, as well as the Commission's request to honor such obligations in the 1982 rate proceedings.

Without question BPA must establish its rates to recover costs and expenses incurred pursuant to section 4(h) of the Act. (Section 7 (A) (1)). Yet the BPA DEIS is inadequate in addressing the relationship of Bonneville's rates process to Bonneville's obligation to protect, mitigate, and enhance fish and wildlife. The discussion that appears in the DEIS is a synopsis of the negative effects dams and other activities have had on migratory fish, efforts to maintain present populations, and a four sentence description of the fish and wildlife program being developed by the Northwest Power Planning Council. (1982 Rates DEIS at VI-12,14). No discussion appears regarding the requirement that the Bonneville Power Administration shall use its fund to protect, mitigate, and enhance the fish and wildlife of the Columbia River basin. (Section 4(h) (10) (a)).

The Inter-Tribal Fish Commission in conjuction with state and federal fish and wildlife agencies of the Pacific Northwest has submitted a Detailed Implementation Plan of phased-in measures to be included to the Power Planning Council's fish and wildlife program. In the first year, funding needs to implement these measures will exceed nine million dollars, the second year funding needs will exceed twelve million dollars, and in the third year, twenty-two million dollars.

These measures reflect the magnitude of the protection, mitigation and enhancement needed for the Columbia River system. By November 15, 1982, section 4(h) (9) requires the Power Planning Council to adopt a fish and wildlife program.

Congress was concerned that protection, mitigation, and enhancement of Columbia River fish and wildlife must not be delayed. The drafters of section 4(h) emphasized that:

> Section 4(h) also requires the BPA to use the BPA fund and its statutory authorities to protect, mitigate and enhance fish and wildlife in a manner consistent with an adopted plan, including the above recommendation, and the purposes of the legislation. It is important to stress once again that the recommendations may well precede the plan. If so, BPA and others should not delay their implementation pending adoption of the plan which will incorporate these recommendations, H.R. Rep. No. 976, 96th Cong., 57 (1980).

The Inter-Tribal Fish Commission trusts that Bonneville's 1982 rate policy will in no way delay immediate implementation of the 4(h) fish and wildlife program. Though Bonneville did consider the possible effects rate revisions may have on operation of the hydroelectric system, it did not address in the DEIS the larger issue. Revenues pursuant to section 4(h) (8) (B) and section 7(a) (1) will be needed to implement protection, mitigation and enhancement for the anadromous fish of the Columbia River basin. Will the 1982 Rate Proposal provide such revenues?

Sincerely,

S. Timothy Wapato

S. Timothy Wapato
Executive Director

RL:vm

cc: Ad Hoc Executive Committee

U. S. ENVIRONMENTAL PROTECTION AGENCY

REGION X

1200 SIXTH AVENUE

SEATTLE, WASHINGTON 98101

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REPLY TO ATTN OF: M/S 443

JUL 6 1982

Anthony Morrell
Environmental Manager
Bonneville Power Administration
P. O. Box 3621-SJ
Portland, Oregon 97208

RE: 1982 Rate Proposal Draft EIS

Dear Mr. Morrell:

The Environmental Protection Agency has reviewed the subject Draft EIS and offers these comments for your consideration.

The Draft EIS does an excellent job of portraying the relationships among electrical rates, energy consumption and environmental quality. It also demonstrates that economically correct pricing signals can serve to minimize the magnitude of environmental consequences associated with meeting the Region's electrical energy needs. Portraying the environmental impacts of generation induced by "improper" pricing represents a worst-case scenario, consistent with the CEQ regulations regarding incomplete or unavailable information (40 CFR §1502.22). Additionally, it provides a commendable discussion of the cumulative environmental impacts of BPA's expected wholesale power rate increases through 1985.

Other EPA comments on the Draft EIS are included in the attachment to this letter. We are pleased to note that nearly all of the suggestions included in our scoping letter of December 4, 1981 have been addressed or incorporated in the DEIS. Based upon these concerns we have rated this EIS LO-1 [LO: lack of objections; 1: adequate information].

Should you wish to discuss these comments with us, please contact Mr. Dick Thiel, my Environmental Evaluation Branch Chief, at (FTS) 399-1728.

Sincerely,

John R. Spencer
Regional Administrator

Enclosure

Detailed Comments on BPA's 1982 Rate Proposal Draft EIS

Page	
V-29	The projected decrease in irrigated agriculture shown here is not consistent with the projected increase described on pages VI-17/18.
V-72	BPA has made a good effort to quantify the impacts of generation avoided as a result of the revenue level alternatives. However, the values shown in table V-22 would be more realistic if a range for each estimate were provided.
V-96/7	The RP-2 rate does not appear to increase all changes, as indicated in the text.
VI-19	Table VI-3 is correct as shown. However, a final rulemaking is expected to be issued next month which will change non-attainment status for certain areas of Idaho. Silver Valley will be changed to "unclassifiable" and Pocatello to "attainment."

U.S. DEPARTMENT OF ENERGY — BONNEVILLE POWER ADMINISTRATION

CONFERENCE AND TELEPHONE CALL REPORT

Date May 13, 1982

cc:
- [x] D. Geiger - PBB
- [x] J. Pyrch - PBE
- [x] J. Taves - PLA
- [ ]
- [ ]
- [ ]
- [ ]

TO: The Files - SJ

FROM: Marcia J. Knapp, Environmental Specialist - SJ

Include all telephone calls and conferences of importance bearing upon policies, customer or public relations, but excluding those purely technical in nature.

OUTSIDE CALLER OR CONFEREE	SUMMARY OF DISCUSSION
Mr. Bob Taylor Bureau of Indian Affairs Environmental Coordinator extension 2208	He had several questions concerning the Draft EIS: 1. In the Executive Summary: What <u>are</u> the shared costs in dollars being transferred to WPPSS 1 and 3? Is it constructio[n] or public indebtedness? Or both? What is indebtedness on bon[d] issue for WPPSS 4 and 5? 2. What is amount of proposed borrowing on new bond issue before end of this month? 3. Why haven't WPPSS costs been put in proposal alternatives? (i.e., amount of borrowing, costs to total public debt?) What effects will WPPSS situation have on small hydro? I told him either I or someone from Rates would get back to hi[m] Each plant -- cost-to-date and cost-to-finish Impact on low income families - Indian Potential effect of WPPSS and 394 on small hydro and expanded efforts in smaller projects

The following comments represent excerpts from or summaries of comments received on BPA's Draft Environmental Impact Statement: Bonneville Power Administration Proposed 1982 Wholesale Rate Increase. The comments and responses to them have been grouped by topic area. The topic areas and their location within the appendix are as indicated below.

I. Rate Design
II. Thermal Plant Financing
III. Effects on the Physical Environment
IV. Effects on Low Income and Other Residential Consumers
V. Effects on Business and Industry
VI. Effects on Irrigation Farming and Food Prices
VII. Miscellaneous

I. Rate Design

Comment: BPA should revise and resubmit the Draft EIS as its proposal to continue the low density discount (LDD) has significant environmental impact since the LDD has worked as an incentive for additional energy consumption (Natural Resources Defense Council, Inc., San Francisco, Calif.).

Evaluation: Section (7)(d)(1) of the Regional Act directs the Administrator to apply discounts, to the extent appropriate, to customers with low system densities in order to avoid adverse impacts on retail rates. BPA has applied either a 3, 5, or 7 percent discount to the wholesale rates of utilities qualifying on the basis of low system densities. This discount reduces the utility's wholesale power cost. How this reduction is reflected in retail rates and passed along to the consumers is left up to the locally elected directors and commissioners.

In the 1982 Wholesale Power Rate Design Study an analysis has been done on the effects of the LDD on wholesale power costs (Table 27, p. 143-147). Even with the maximum 7 percent discount, most of BPA's customers faced wholesale rate increases of about 70 percent. The deterrent effect on conservation of the LDD discount, when compared to the considerable incentive to conserve generated by the overall rate increase, can not be classified as having a significant negative environmental impact. Further, the higher rates for customers not receiving the LDD, yet paying for the cost of the LDD, create additional incentive to conserve. At this time, further BPA analysis is not warranted.

Comment: Page V-104. First full paragraph notes that use of nonfirm energy to serve top quartile loads "could perhaps result in displacement of fewer firm thermal resources and therefore could be contrary to BPA's obligation to keep overall rates as low as possible consistent with sound business principles." Contrary to the implication of the paragraph in the Draft EIS, BPA's policy of serving the top quartile with nonfirm power prior to displacing resources minimizes the costs and environmental impacts of BPA's resources. Displacement of thermal resources prior to serving the top quartile would simply reflect a decision not to serve a portion of the DSI load that is dependent on power in excess of critical planning amounts for service; it does not reflect the least cost way of serving BPA's total load. The paragraph should be deleted or revised (Direct Service Industries, Inc., Portland, Oregon).

Evaluation: The paragraph has been modified so as to address the comment.

Comment: Page V-104. The first three lines of the second full paragraph should be revised to read as follows: "A third method of serving the top quartile also involves advancing energy from a later period into an earlier period. As with shifting of FELCC, the success of advancing energy is dependent upon streamflow..." (Direct Service Industries, Inc., Portland, Oregon).

Evaluation: The paragraph in question has been modified so as to address the comment.

Comment: Page V-106. The second full paragraph suggests an alternative " . . . would be to eliminate any compensation to the DSI's associated with the restriction rights." This would violate section 7(c)(3) of the Regional Act which requires that rates charged the DSI's reflect the value of reserves that they provide. The sentence should be removed (Direct Service Industries, Inc., Portland, Oregon).

Evaluation: The agency is not precluded from considering alternatives not currently within the scope of its authority.

Comment: Page V-102. The paragraph beginning on line 18 discusses DSI reserve credits. The last two sentences state, "If not restricted, the resulting purchase power costs incurred by BPA would be directly assigned to the DSI bill. However, because the estimated purchases were so small, a purchase before restriction clause was not included in the IP-2 rate schedule." This statement is not factual and should be changed (Direct Service Industries, Inc., Portland, Oregon).

Evaluation: The paragraph has been deleted.

Comment: Your policy indicates that customers in the northwest have a priority for power produced in the northwest. When dump power is sent to California their rate should be the equivalent of our rate and during the dump period we in the northwest should receive our power at the dump rate (John Pierce, Malta, Idaho).

Evaluation: The preference clause of the Bonneville Project Act limits BPA sale of energy outside the Pacific Northwest to that which is surplus to the power requirements of the Northwest. BPA bases its planning on critical water conditions and when better than critical conditions occur, the excess energy available is marketed as nonfirm. Because the availability of nonfirm energy is uncertain in nature, it is considered to be lower in quality than firm power and, therefore, is marketed at a lower price. Nonfirm energy is marketed at a spill rate only when dump conditions exist on the Federal system. The energy is offered first to Pacific Northwest public utilities, then to Pacific Northwest private utilities and finally to Pacific Southwest utilities. Northwest utilities can use the nonfirm energy to serve their loads and either shutdown their higher cost resources or sell power from their high cost resources to the Pacific Southwest.

Comment: Page V-107. The paragraph beginning on line 19 and the first paragraph on page V-108 suggest tiered rates could be developed to provide a different rate for the top quartile than for the bottom three quartiles. This goes against the concept of a unified class of power for the DSI's (Direct Services Industries, Inc., Portland, Oregon).

Evaluation: In the Memorandum of Bonneville Power Administration Counsel which was prepared as a part of the proposed 1982 rate adjustment process, legal counsel stated its opinion that a two-part rate for service to the DSI's is lawful and consistent with the Administrator's authority as delegated by Congress. Reference is made to that document for further information.

Comment: The RP-2 rate does not appear to increase all charges, as indicated in the text (U.S. Environmental Protection Agency, Seattle, Washington).

Evaluation: The proposed RP-2 rate represents a decrease over the existing RP-1 rate; therefore, correction has been made.

Comment: BPA's effort to recover a portion of the costs of its conservation programs through direct charges to participating utilities imposes a barrier to regional conservation efforts. BPA must address this issue, explain the reasons for its actions and analyze environmentally preferable alternatives (Natural Resources Defense Council, San Francisco, California).

Evaluation: The contract charge assumed for the initial proposal was a systematic approach for sharing costs between BPA and conserving utilities. This approach recognized that a conserving utility has some incentive to perform conservation measures and that BPA should have to subsidize measures only to the extent that they do not appear cost effective to the utility based on its wholesale rate. The sharing of costs by use of the contract charge was designed to achieve two important objectives: (1) hold nonparticipants harmless by recognizing the lost revenue effect at the wholesale level, and (2) address the equity problem between generating and nongenerating utilities.

BPA's initial proposal does not address the lost revenue problem at the retail level, which is especially serious because of the large percentage of fixed costs at the retail level. BPA's initial proposal would give local utilities the dilemma of having conservation drive the retail rate up significantly or assigning such a large share of the costs to the individual conserver as to jeopardize the program. It would be possible to address the retail lost revenue problem while retaining the contract charge by adjusting the program incentive levels. However, elimination of the contract charge would probably be the simplest and most straightforward way to address this problem in the near term.

The inclusion of the contract charge in this rate proposal is not meant to preclude the contract negotiators from working out a different arrangement for sharing the costs between the conserving utility and BPA. BPA has been having meetings with its customers, both in connection with this rate filing and the conservation contract negotiations, to discuss the allocation and recovery of conservation costs. No concensus has been reached and many details concerning calculation of achieved saving, timing of payments, and conservation by non-utility entities remain to be worked out. If appropriate, the consensus decision on the allocation and recovery of conservation costs would be subject to environmental assessment.

Comment: What is the impact on retail rates, and on specific customer classes of this proposed wholesale rate increase? (Bureau of Indian Affairs, Portland, Oregon).

Evaluation: It is impossible for BPA to predict the exact impact of its revenue increase, at the wholesale level, on the customer utilities' retail rates. Chapter V, pp. 18-25, discusses this issue in detail.

Comment: BPA needs to address the environmental impact of retaining a demand charge rather than eliminating such charges and imposing offsetting increases in energy rates which would have regional benefits (Natural Resources Defense Council, San Francisco, California).

Evaluation: It is not believed that elimination of demand charges and recovery of BPA's revenue exclusively through an energy charge would have significant environmental effects. The reasons for this conclusion are two-fold. First, most retail consumers already face no demand charge. Elimination of the demand charge at the wholesale level would have virtually no effect on electricity use by such consumers. Second, the direct service industries served by BPA do face a demand charge; however, they employ continuous production cycles and would also be virtually unaffected by elimination of demand charges. No further analysis was done for the final EIS in response to this comment.

Comment: The Draft EIS does not adequately address the issue of a tiered rate structure (Natural Resources Defense Council, San Francisco, California).

Evaluation: The information on tiered rates has been supplemented by an addition to Section V.D.1.c.(1) and a reference to Appendix B (Tiered Rates) of BPA's 1982 Wholesale Power Rate Design Study.

III. Thermal Plant Financing

Comment: Why haven't the Supply System termination costs for plants 4 and 5 been put in the proposed alternatives (i.e., amount of borrowing, costs to total public debt)? What effects will WPPSS have on small hydro? (Bureau of Indian Affairs, Portland, Oregon).

Evaluation: The Supply System costs for terminating plants Nos. 4 and 5 were not included in the proposed alternatives since they do not directly affect the BPA wholesale rates. Borrowing by the Supply System has been included in the rate analyses through the 1982 Time-Differentiated Long Run Incremental Cost Analysis which identifies incremental costs incurred to meet load growth requirement, or saved by not meeting an additional increment of load.

The effects of the Supply System on small hydro should be minimal. The Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) directs BPA to acquire sufficient resources, which are cost effective, first from conservation, second from renewable resources, third from generating resources using waste heat or of high fuel efficiency, and fourth from all other resources. The activities of the Regional Council are likely to be supportive of small hydro in comparison to expanding the Supply System program to include five plants.

The Regional Act clearly delineates small hydro as an important resource. However, the energy load growth rates are likely to be the most important indicator of needed new power resources in the region. BPA's draft load forecasts take into account both the conservation and consumer owned resources which are developed in response to higher retail electricity prices and the conservation savings anticipated as the result of near-term BPA conservation programs. Additional conservation and renewable resources may be achieved to meet rapid unanticipated increases in regional loads.

The region's future power needs, forecasting uncertainties, and the desirability of having additional resources near-at-hand dictate that BPA's existing and announced conservation and small (under 5 average megawatts) renewable resources programs should continue to operate during the period of surplus indicated in BPA's draft forecast of regional energy load. BPA considers these programs to be valuable, unfinished resources and will make an aggressive effort to complete them.

The cost-effectiveness test for conservation and small renewable resources in this period will reflect the reduced value of the resources during the probable near-term surpluses.

BPA will continue to emphasize its residential conservation programs. These programs have been offered to all regional utilities and are underway in 96 utility service areas. The programs offer increased energy efficiency to qualifying households with electric space or water heat in these service areas at little or no cost to the homeowner.

Commitments to large renewable resources will be made on the basis of an extended planning horizon showing need for new power resources in the post-1990 period. BPA plans to continue to develop its policy, program, and organizationalcapability in renewables in order to be able to address this need effectively.

The principles of cost-effectiveness and the protection of the ratepayers' interest in assuring an adequate and reliable power supply will continue to be paramount in BPA's decisions and actions on conservation and renewable resources development as required by the Regional Power Act.

Comment: What is the amount of the proposed borrowing on the new bond issue before the end of June? (Bureau of Indian Affairs, Portland, Oregon).

Evaluation: The sale figure was $680 million

Comment: In the Executive Summary (p. II-1): What are the shared costs in dollars being transferred to WPPSS Nos. 1 and 3: Is it construction or public indebtedness? Or both? What is indebtedness on bond issue for WPPSS No's. 4 and 5? (Bureau of Indian Affairs, Portland, Oregon).

Evaluation: The Supply System No. 1 and No. 4 plants were intended to be constructed adjacent to one another. This was also the case with respect to the No. 3 and No. 5 plants. This would have permitted the achievement of certain economies of scale because a number of facilities (e.g., access roads) could be shared by adjacent plants. As a result of the termination of the No. 4 and No. 5 plants, these total costs are now being borne by plants No. 1 and No. 3.

The bond prospectus of May 1, 1982, indicates that the shared costs of No. 3 with No. 5 will increase by an estimated $235 million as a result of termination of the No. 5 plant. No estimate is listed for the shared cost to be attached to No. 1 from No. 4.

As of the termination date, the Supply System had issued an outstanding $2.25 billion principal amount of the Nos. 4 and 5 bonds. Debt service is currently funded to March 1, 1983. The Supply System has also issued $60 million in subordinated revenue notes, interest and principal on which is due July 1, 1984, and is expected to issue additional subordinated notes under the termination notice of Nos. 4 and 5.

IV. Effects on the Physical Environment

Comment: BPA has made a good effort to quantify the impacts of generation avoided as a result of the revenue level alterntives. However, the values shown in table V-22 would be more realistic if a range for each estimate were provided (U.S. Environmental Protection Agency, Seattle, Washington).

Evaluation: A notation calling that to the attention of the reader has been added to the discussion of Table V-22.

Comment: Since wood burning is becoming a rapidly growing source of air pollution, the effects upon ambient air quality should be considered (Department of Health and Human Services, Atlanta, Georgia).

Evaluation: The section on the effects of direct combustion of wood for home heating on the physical environment is in Chapter V. Further reference to the impact of wood burning has been added to the Air Quality section.

Comment: No discussion appears regarding the requirement that BPA shall use its fund to protect, mitigate and enhance the fish and wildlife of the Columbia River basin. Revenues will be needed to accomplish this charge. Will the 1982 Rate Proposal provide such revenues? (Columbia River Inter-Tribal Fish Commission, Portland, Oregon.)

Evaluation: The 1981 rate proposal included $2,148,000 in costs for the FY 1982 fish and wildlife program mandated by the Regional Act. These funds are to be used to offset costs incurred to "protect, mitigate, and enhance fish and wildlife to the extent affected by the development and operation of any hydroelectric project of the Columbia River and its tributaries" (see the Act, sections 4(g) and (h)). In the 1982 rate proposal for FY 1983, $10,437,000 in costs (an increase of 386 percent from the 1981 proposal) have been allocated to the fish and wildlife program.

Comment: Page VI-13. Beginning at line 6 the statement is made, "...have eliminated salmonoid spawning except in the reach from Lake Wallula to Priest Rapids Dam (the Hanford reach)." Is there no spawning in the Rocky Reach and Wells pools and rivers/streams tributary thereto? (Direct Service Industries, Portland, Oregon).

Evaluation: BPA acknowledges that there may be minor salmonoid spawning activity in other areas of the Columbia River and its tributaries. However, this activity is considered to be relatively insignificant. BPA views the only major natural salmonoid spawning area to be below Priest Rapids Dam to the head of Lake Wallula, otherwise known as the Hanford Reach.

V. Effects on Low Income and Other Residential Consumers

Comment: Middle and low income people can not afford any more price hikes (Mrs. L. Kile, Odessa, Washington).

Evaluation: BPA is sensitive to the impact of rising electricity prices on low and fixed income groups and has identified that impact as an area of particular concern (Chapter VI). No further analysis has been done for the final EIS.

Comment: Power needs were overestimated and demand has declined. Therefore, lower the rates so that people on fixed incomes can stop shivering in cold houses (Joe Branden, Brookings, Oregon).

Evaluation: The decline in the consumption of electricity is due to the increase in the price of electricity, the general economic condition of the country and conservation actions by consumers. The effect of lowering rates would be that consumption would increase and fewer conservation actions and investments would be made. The increase in consumption would result in the construction of additional generation facilities (coal and nuclear) which in turn would cause a dramatic increase in rates over the long term. The optimal action would be to improve the efficiency with which energy is consumed through conservation actions such as weatherizing homes. That way less energy would be consumed, thereby slowing the upward spiral of rates which are tied to generation costs. Refer to Chapter V for discussions of impact from the rate level alternatives. No further analysis for the final EIS has been done.

Comment: What will be the impact of these proposed wholesale rates on low income urban Indians? (Bureau of Indian Affairs, Portland, Oregon).

Evaluation: The population group, low income urban Indians, has not been specified separately in the draft EIS. The broader group entitled low income residential customers is discussed in Chapter VI. There is no question that the escalating costs of energy have had a disproportionate impact across residential consumers, with the lower income groups spending a higher percentage of their incomes for aggregated energy costs.

Low income urban Indians will likely suffer the same consequences as other low income consumers. Energy costs have had a disproportionate impact on all low income residential households. This is discussed in greater depth in Chapter V.

VI. Effects on Business and Industry

Comment: You can't attract badly needed industry to the Northwest with high power costs (Joe Branden, Brookings, Oregon).

Evaluation: Generally speaking, the price of electricity is not a determining factor in economic viability of business and industry when compared with factors such as the costs of labor, materials, production process equipment and transportation. For the industries in which electricity is a major cost factor in production, it is expected that high power costs could influence plant location. The Pacific Northwest continues to have a comparative advantage in rates. A discussion of the effects of electricity price increases on business and industry is in Chapter V.

Comment: Page V-111, line 11. Remove the word "industrial." All ratepayers likely would be impacted (Direct Service Industries, Inc., Portland, Oregon).

Evaluation: Correction has been made on page.

Comment: Page IV-9. The first partial paragraph discusses BPA's 1979 and 1981 rate increases to preference customers. We believe the cumulative effects of the 1979/81 rate increases have been at least as severe on DSI operations. These should also be listed and discussed. Page V-2. Same comment as on page IV-9 (Direct Service Industries, Inc., Portland, Oregon).

Evaluation: Analyses in Chapter IV and V have been modified so as to incorporate comments.

Comment: Page V-108, Subsection D. Add a sentence somewhat as follows: "The greater curtailments would cause socioeconomic impacts of higher unemployment and loss of other revenues associated with DSI operation." BPA perhaps should add data on DSI employment and economic benefit to the region. (Direct Service Industries, Inc., Portland, Oregon.)

Evaluation: The discussion in Chapter V has been modified to reflect the general intent of the comment. Reference is also made to Section VI(B)(2)(b) on socioeconomic impacts associated with energy intensive industries.

VII. Effects on Irrigation Farming and Food Prices

Comment: Irrigators should not be permitted to intimidate needed power rate increases to the detriment of environmental quality (Bruce Bowler, Boise, Idaho).

Evaluation: BPA attempts to design rates which are fair and equitable for all its customers without making special concessions for any customers, customer group, or customer class which are not defensible on cost or value basis or which are not legislatively mandated. BPA has phased out special irrigation promotion rates based on current costs of providing service to this group. The proposed rates do provide a lower charge for power taken during the offpeak period, to the extent that irrigators can take advantage of and benefit from the offpeak service provision, they can reduce their costs for a given demand level of electric service.

Comment: The Executive Summary states that there would be 762,000 more acres under irrigation by the year 2000 under the LRIC alternative; this should probably be 762,000 less rather than more (U.S. Department of the Interior, Washington, D.C.).

Evaluation: The correction has been made.

Comment: In reviewing present and future power costs, Dr. Whittlesey claims, "...it is estimated that between 1982 and 1985 the average cost of retail power to irrigated agriculture will increase by 14.8 percent in nominal dollars." Apparently Dr. Whittlesey isn't aware that BPA has proposed a 73 percent rate increase for October 1, 1982, which will require a 37 percent increase at the retail level for irrigators served by our co-op. He should also be reminded of WPPSS 4 and 5 cost, which, for many utilities, will amount to retail rate increases of over 14.8 percent (Big Bend Electric Co-Operative, Inc., Ritzville, Washington).

Comment: On Page VII-18, Line 6, the Draft EIS states a retail rate increase of 28.7 percent; our actual rate went from 1.01¢/kWh in 1979 to 2.21¢/kWh in 1981 - that is a 118.8 percent increase. We are projecting a 33 percent increase for the 1981-82 period versus the report's 19.4 percent. We project a rate increase for the 1982 to 1985 period of 59.9 percent versus the report's 14.8 percent. Dr. Whittlesey's numbers just don't compare with those for utilities that are facing the 73 percent BPA rate increase this fall and WPPSS 4/5 payments the first of 1983 (Columbia Rural Electric Association, Inc., Dayton, Washington).

Evaluation: Section has been modified to address concerns.

Comment: Footnote C of Table VI is somewhat confusing. It indicates the fiscal year 1983 repayment requirement was reduced by excluding irrigation assistance. The first irrigation assistance is not due until 1997. It is not clear how the irrigation assistance impacts the repayment requirement for 1983 (U.S. Department of the Interior, Washington, D. C.).

Evaluation: The footnote is technically correct and the value assigned to irrigation assistance until 1997 is zero.

Comment: The projected decrease in irrigated agriculture shown on page V-29 is not consistent with the projected increase described on pages VI-17/18 (U.S. Environmental Protection Agency, Seattle, Washington).

Evaluation: The information projecting increases in irrigated acreage was from a study dated 1979. This data may not have reflected the past and proposed BPA rate increases and, therefore, has been deleted from the final EIS.

Comment: The final EIS should address impacts which reduced irrigated farming will have on health and nuisance problems, such as mosquitos (Department of Health and Human Services, Atlanta, Georgia).

Evaluation: Reference to the possible impact of decreased irrigated farming, on health, and nuisance problems has been added to the appropriate section.

Comment: The irrigation rates for April and May should be on the summer schedule. Normally you are spilling water during these months (John Pierce, Malta, Idaho).

Evaluation: The summer period should not be extended to include March, April, and/or May based on the results of BPA's studies. BPA designs its seasonal periods based on a Probability of Negative Margin Analysis (PONM) which analyzes available resources and loads and computes the probability of loads exceeding available resources. Based on these results, the summer season for capacity is June through November and the winter season for capacity is December through May. If the results of the PONM were different, BPA would reassess its summer period. The summer energy rate does start in April.

Comment: I understand a Nickle mining company within the Willamette Valley has been given special consideration for their rates. You certainly can justify reinstating the 15% irrigation discount (John Pierce, Malta, Idaho).

Evaluation: The special industrial rate is described in Section V(D)(9). Provision for the special industrial rate is in Section 7(d)(2) of the Regional Act which allows this rate to be established for any direct-service industrial customer using raw materials indigenous to the region. The Regional Act contains no similiar provision for irrigation. BPA has phased out special irrigation rates and bases rates on current costs of providing service.

Comment: You are spending 5 and 6% of the firm resource revenue projection of your budget for conservation. I assume 5 to 6% of my pump bill goes to conservation. We are doing everything we can for conservation as individuals and as a Cooperative; don't make us pay twice. Reduce our bill 5 to 6%. (John Pierce, Malta, Idaho.

Evaluation: The conservation charge, as cited, is at a wholesale level and is not necessarily reflective of the conservation charges at the retail level. BPA shares the costs of implementing conservation programs with the utilities since conservation is assumed to produce a reduction in load. The rules for sharing costs between the utility and conserver apply to BPA and its utility customers, at the wholesale level. To avoid an adverse effect on its retail rates, the retail utility can subsidize conservation up to the difference between the marginal cost, which for a BPA requirements customer is the wholesale rate plus any variable distribution costs, and its retail rate. This issue is discussed in detail in the Cost-of-Service Analysis. No further analysis was not done for the final EIS in response to this comment.

VIII. Miscellaneous

Comment: Table VI-3 is correct as shown. However, a final rulemaking is expected to be issued next month which will change non-attainment status for certain areas of Idaho. Silver Valley will be changed to "unclassifiable" and Pocatello to "attainment" (U.S. Environmental Protection Agency, Seattle, Washington).

Evaluation: A notation with that information has been added.

Comment: Page IV-4 The first paragraph should recognize that if the Federal Base System resource pool is larger than the sum of the preference customer, federal agency and residential exchange loads, the excess would be used to supply DSI loads (Direct Service Industries, Inc., Portland, Oregon).

Evaluation: The above information has been added.

Comment: Page V-3, line 20. The $1.619 billion is given as $1.709 billion on page IV-6 (Direct Service Industries, Inc., Portland, Oregon).

Evaluation: Correction of information has been made.

Comment: Page V-7, line 26. The $821 million is given as $731 million on page IV-6 (Direct Service Industries, Inc., Portland, Oregon).

Evaluation: Correction of information has been made.

Comment: Page V-101, line 8, lists the present energy reserve credit as 2.3 mills per kilowatthour. This credit is 2.1 mills. (Direct Service Industries, Inc., Portland, Oregon)

Evaluation: Correction of information has been made.

Comment: The reference to the National Historic Preservation Act (NHPA) of 1966, as amended, Section 6, should refer to NHPA, Section 106 (Office of Archaeology and Historic Preservation, Olympia, Washington).

Evaluation: Because of other changes, the EIS no longer cites the NHPA.

Comment: How will owners of the state's historic mansions cope with high rates once all feasible energy conservation methods have been undertaken? (Montana Historical Society, Helena, Montana.)

Evaluation: Impacts to properties on or eligible for the National Register of Historic Places are not included within the range of impacts caused by the proposed 1982 rate increase. While owners of these properties may undertake measures (e.g., weatherization) to mitigate economic effects of generally increasing energy costs, and while the measures may indeed have effects to the properties, it is not reasonably foreseeable that the 1982 rate increase in itself would generate these effects. Therefore, impacts to properties on or eligible for the National Register of Historic Places is outside the scope of this EIS and not considered further.

However, separate from the 1982 rate increase, BPA is proposing several conservation programs, including weatherization. In considering the environmental effects of these programs, BPA will consult with the Advisory Council on Historic Preservation and the State Historic Preservation Officers to determine effects on National Register or eligible properties and to develop means of avoiding adverse effects.

Comment: We believe a thorough discussion in the Environmental Impact Statement of adequate rates for export power, the impacts of such rate on the development of resources both in the Pacific Northwest and in the Pacific Southwest, and the environmental, social, and economic aspects of the alternatives would be very appropriate. Perhaps there has not been sufficient analysis of the resource alternatives to appropriately develop this scenario, but the adequacy of rates for the export market could be a substantial element of any such overall analysis (Direct Service Industries, Inc., Portland, Oregon).

Evaluation: There is currently insufficient information for BPA to undertake an analysis such as specifically posed in the comment. Environmental, social and economic assessment of BPA's export (nonfirm) rate is complex to perform. In the past, the nonfirm energy rate varied throughout the year as it was based upon several determinations: competitive market conditions, the quantity of nonfirm energy available to sell, and the capacity of the Pacific Northwest-Pacific Southwest Intertie (Intertie) for sales to California. The proposed NF-2 nonfirm energy rate is substantially different from previous nonfirm energy rates. It is intended to gain greater customer acceptability than the previous rates, while maintaining an equitable price for nonfirm energy. Public Law 88-552, guarantees electric consumers in the Pacific Northwest first call on electric energy generated at Federal hydroelectric plants in the region. When Northwest utilities choose not to purchase this energy, it is offered to customers outside the region. BPA sales of nonfirm energy to the Pacific Southwest are limited by Intertie capacity and contractual arrangements regarding its use. The Intertie is the transmission link to California with a total scheduling capacity of 4056 megawatts. When there is export power to be sold, there is competition for the limited space on the Intertie which has the effect of driving down the price of the power which can be sold.

While information is lacking at this time to conduct a comprehensive analysis as noted above, BPA will attempt to fully address the resource development, environmental, social, and economic impacts of nonfirm rates in future rate proceedings.

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