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Bonneville Power Administration

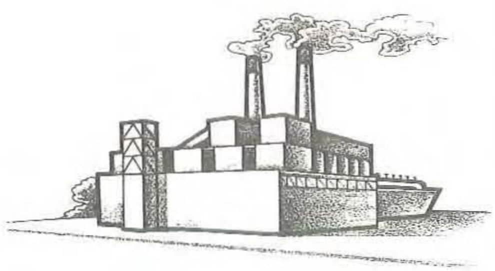
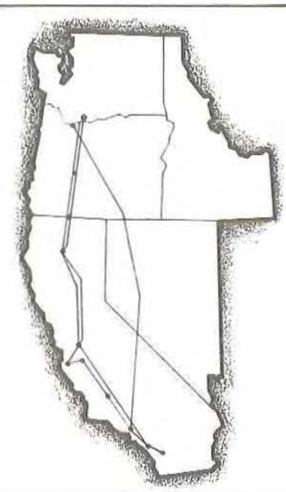
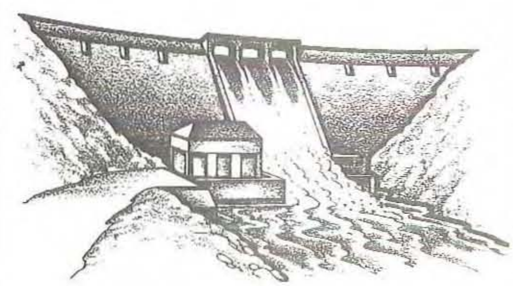
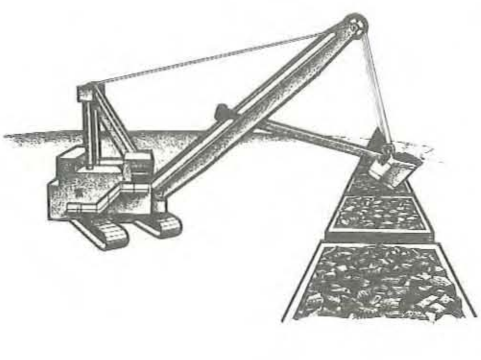
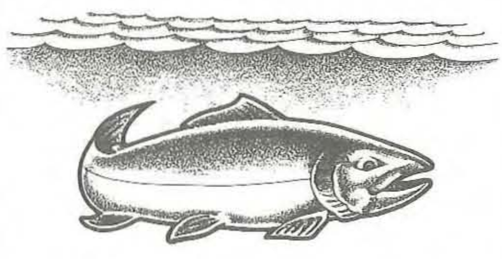
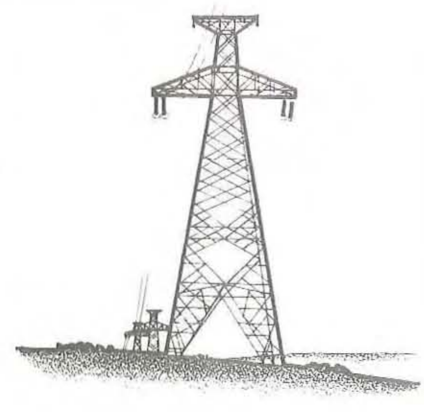
Final Environmental Impact Statement

INTERTIE DEVELOPMENT AND USE

U.S. Department of Energy

April 1988

Volume 1: Environmental Analyses

Bonneville
Power
Administration

Final Environmental Impact Statement

INTERTIE DEVELOPMENT AND USE

U.S. Department
of Energy

Volume 1: Environmental Analyses

FINAL ENVIRONMENTAL IMPACT STATEMENT

Responsible Agency: U.S. Department of Energy, Bonneville Power Administration.

Title of Proposed Action: Intertie Development and Use.

Cooperating Agencies: U.S. Army Corps of Engineers; U.S. Department of the Interior, Bureau of Reclamation; U.S. Department of Energy, Western Area Power Administration.

States and Provinces Involved: Washington, Oregon, Idaho, Montana, Wyoming, California, Nevada, Utah, New Mexico, Arizona, British Columbia.

Abstract

- The Bonneville Power Administration (BPA) has identified the need to enable short- and long-term contractual sales of Federal power surplus to Northwest loads and to manage other interregional transfers of power over the Pacific Northwest/Pacific Southwest Intertie. There are three proposed options: to increase the capacity of the Intertie; to adopt a Long Term Intertie Access Policy (IAP), which will set the ground rules for use of the Intertie by utilities other than BPA for short- and long-term transmission of surplus power to California; and options whereby BPA would promote, through its access policies and marketing efforts, various types and levels of firm power marketing between the Northwest and California. The LTIAP also addresses access to the Intertie for new resources, access as it relates to the Administrator's efforts to enhance fish and wildlife and access to the Intertie by extraregional utilities.

- Intertie capacity, presently 5,200 megawatts (MW), is being increased to 6,300 MW (DC Terminal Expansion) and may be increased further (Third AC/California-Oregon Transmission Project) to approximately 7,900 MW.

- Access for regional and extraregional entities to BPA's portions of the Intertie is governed now by the Near Term Intertie Access Policy. Intertie access could be regulated by returning to a non-allocated approach or by a combination of options. These include different options for the allocation of access for economy and nonfirm energy sales over the portion of the Intertie not required to support long-term sales; options for the provision of assured delivery for long-term firm power sales; ways to govern access for power from new resources and from hydroelectric resources which could adversely affect BPA's efforts to protect fish and wildlife; and ways to allocate access for entities outside the Pacific Northwest region.

- Intertie capacity expansion would create a slight increase in air pollution from coal generation in the Pacific Northwest and slight improvements in air quality in California and the Inland Southwest. The upgrades could result in some negative effects on anadromous fish stocks, but these are not likely to be significant in the context of planned fish passage improvements and management programs.

- BPA's Proposed Formula Allocation for economy energy sales would not have significant effects on the environment. The Hydro-First option would slightly improve air quality in the Northwest, but it could have some adverse effects on resident fish and anadromous fish. Both the Proposed Formula Allocation and Hydro-First options would increase BPA revenues, but not significantly affect retail rates in the Northwest or California.

- Long-term firm contracts would allow some new resource construction to be deferred in both the Northwest and California. There would be no appreciable effects on air quality in the Northwest for all cases and a slight improvement in California and the Inland Southwest under the Assured Delivery case. These cases would result in slight increases in anadromous fish survival and minor adverse effects on some resident fish.

- The economic analysis shows both the DC Terminal Expansion and the Third AC/COTP to be cost effective. The net benefit of the Maximum Upgrade, assuming adoption of the proposed IAP, but no addition of new firm sales, would be $1,657 million. The net benefit of the Proposed Formula Allocation is slightly negative, but this small impact is overshadowed by the approximate total benefit of the Interties of about $15 billion. The net benefit of long-term firm contracts under the Assured Delivery option would be $651 million for the Existing Intertie and $819 million for the Maximum Upgrade.

This final EIS is being mailed to agencies, groups, and individuals (see Chapter 6).

For Additional Information on the EIS or a copy of the EIS: Anthony R. Morrell, Assistant to the Administrator for Environment, Bonneville Power Administration-AJ, P.O. Box 3621, Portland, Oregon 97208; Area Code (503) 230-5136.

(VS6-PG-1848Z)

SUMMARY

SUMMARY

Introduction

This environmental impact statement examines the environmental effects of three proposed Bonneville Power Administration actions with respect to the use and development of the Pacific Northwest/Pacific Southwest Intertie. The actions are: expansion of the capacity of the Intertie; adoption of a Long-Term Intertie Access Policy (IAP), which will set the ground rules for use of the Intertie by utilities other than BPA for short and long-term transmission of surplus power to California; and decisions by BPA to enable, through its access policies and marketing efforts, various types and levels of firm power marketing between the Northwest and California.

BPA is proposing these actions in order to make possible additional short and long-term sales of Federal power surplus to that needed for serving Northwest loads and to increase the ability to deliver surplus power when the surplus is most valuable to the importing region. Additionally, the actions are needed to increase economic efficiency, to support environmental quality goals, and to enhance the ability of BPA to repay its U.S. Treasury investment in a timely fashion while maintaining reasonable power rates for its wholesale customers in the Northwest. There is a need for an equitable procedure to allocate access to Intertie capacity that is excess to what BPA requires for its own use and to provide opportunities for assured access to make possible long-term firm power transactions by utilities other than BPA.

Areas of Controversy and Major Issues To Be Resolved

BPA markets wholesale electric power to several customer groups within the region. Under provisions of the Pacific Northwest Electric Power Planning and Conservation Act and the Pacific Northwest Regional Preference Act, BPA may sell surplus power not needed in the region to entities outside the region. Since it was completed in 1968, the Intertie has transmitted firm and nonfirm energy, power and capacity between the Pacific Northwest and California. Congressional intent in authorizing the Intertie was to increase BPA revenues (and thus allow BPA to repay its considerable construction debt to the U.S. Treasury); to make efficient use of resources in the Northwest and California; and to provide an equitable distribution of benefits to both regions.

Many of the issues surrounding Intertie use and expansion have been the subject of public debate and controversy over the past several years. Plans to expand the Intertie have provoked questions from the public about possible environmental impacts, particularly impacts on fish and wildlife. The economics of Intertie expansion have also been a controversial subject.

BPA's Intertie access policies have received a great deal of public scrutiny. Environmental groups have questioned the effects changes in access policies would have on protection of fish and wildlife and on the rate of new resource development in the Northwest. Non-Federal utilities in the Northwest have questioned the access policies from economic and legal standpoints. Extraregional utilities are concerned about the amount of access they have to the Intertie. In summary, the major issues to be resolved by the BPA Administrator with respect to Intertie development and use that are examined in this EIS are:

-- Whether to participate in the development of additional capacity of the Intertie;

-- How to allocate access to the Intertie for economy energy sales;

-- How to establish access to support long-term firm power sales for utilities other than BPA;

-- How much and what kind of access should be allowed for new resources;

-- Whether to limit hydroelectric power access to the Intertie when it would interfere with the Administrator's efforts to protect fish and wildlife; and

-- Whether and how to allow access to the Intertie for extraregional utilities.

Description of Alternatives

Intertie Expansion

Four options for Intertie expansion are considered in the EIS. The first is the No Action, or Existing capacity, option. This option would mean maintaining the current capacity of the AC Intertie at about 3,200 MW and the DC Intertie at about 2,000 MW, for a total of 5,200 MW. The existing Intertie system consists of one direct-current (DC) and two alternating-current (AC) high-voltage transmission lines that extend from the northern border of Oregon on the Columbia River to central California (AC lines) and southern California (DC line).

The existing system can accommodate all requests for transmission of surplus nonfirm energy much of the time, but during abundant water years, more electricity can be produced than can be sent to California. In addition, Existing capacity constrains the amount of surplus firm power that can be sent during the hours when the power is most valuable to California, thus reducing potential income for the Northwest. BPA estimates that through the year 2030, the benefits of the Intertie would be $1,657 million less with the Existing capacity than with Maximum capacity (net present value in 1987 dollars). (This assumes that BPA's proposed Intertie Access Policy would be adopted, but that no new long-term firm contracts would be established between the Northwest and California. If expanded capacity were used to support additional long-term firm contract sales, the value of Maximum capacity would exceed that of the Existing capacity case by $1,976 million. 1/)

The second alternative, the DC Terminal Expansion Project, would increase the capacity of the DC Intertie facilities by approximately 1,100 MW. The effects of this construction were addressed in environmental studies in 1985 and 1986. Based on those analyses, which this EIS updates, the Department of Energy issued a Finding of No Significant Impact (FONSI) on the project in August 1986 and construction began in April 1987. The FONSI was challenged in the Ninth Circuit Court of Appeals by the State of Idaho and others. The Court directed BPA to prepare an EIS addressing the Terminal Expansion Project and its relationship to related Intertie decisions. BPA has agreed to complete the IDU EIS before making decisions on operation of the DC Terminal Expansion Project.

Because the construction required for the project is limited to increases in the capacity of the converter stations and only minor line modifications, the costs of this upgrade are small, both economically and environmentally, compared with building a new line. The estimated present value cost for the project is approximately $376 million. All north-to-south deliveries over the DC Intertie accorded other Northwest utilities will be subject to BPA's Intertie Access Policy, as DC Intertie facilities in Oregon are wholly owned by the Federal government. BPA's studies show that, based on its value in providing transmission for additional economy energy sales, but no additional firm sales, and assuming adoption of BPA's proposed IAP, the project has an expected net present value of $996 million. If the Intertie is used for firm contracts with California, the value of the project would increase to $1,026 million. 2/

The third alternative, the Third AC Intertie/California-Oregon Transmission Project, would increase the capacity of the AC Intertie facilities by approximately 1,600 MW. The California-Oregon Transmission Project (COTP) was proposed by a consortium of publicly and privately owned California utilities, with the Transmission Agency of Northern California as the Project Manager. The Western Area Power Administration, as the lead Federal agency, prepared a joint Environmental Impact Report/Environmental Impact Statement concerning the effects of project construction. Bonneville has been a cooperating

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1/ It should be pointed out that the difference of $319 million in the value of increased Intertie capacity with and without firm contracts represents only the portion of the firm contract benefit associated with firm sales enabled by the DC Upgrade and Third AC Intertie projects. Total benefits of firm contracts are given in the Assured Delivery discussion beginning on page 5.

2/ The difference in the value of the Terminal Expansion with and without addtional firm contracts ($30 million) represents only a small portion of the overall value of using the Intertie for firm transactions.

agency in preparing the EIR/EIS. That EIR/EIS examines the potential construction impacts of upgrading 170 miles of existing transmission line owned by Western in California from 230 to 500 kV and constructing approximately 170 miles of new 500 kV line in California and about 8 miles in Oregon. It summarizes the analyses of the project's environmental impacts resulting from changes in PNW power system operations. This EIS also contains information on the effects of operating the Third AC.

The COTP project would upgrade the capacity of the southern portion of the Intertie to 4,800 MW. To be able to use this expanded capacity fully, the northern portion of the system would be reinforced to increase its capability to 4,800 MW. This reinforcement, the Third AC project, would require modification of facilities at several substations and capacitor stations in the Northwest and could also involve the use of a planned upgrade from 230 kV to 500 kV of an existing Pacific Power and Light transmission line between Eugene and Medford, Oregon.

Only that portion of the capacity of the Oregon facilities of the AC Intertie owned by BPA would be subject to the IAP. Total present value costs of the Third AC/COTP are estimated to be $883 million. BPA's analysis predicts the Third AC/COTP has a net present value of $661 million (1987 dollars), based on its use for additional economy energy sales, and assuming adoption of the proposed IAP. If the Third AC/COTP is used for additional firm capacity contracts, its net present value (in addition to the DC Terminal Expansion) would be $950 million. 3/

The fourth alternative, the Maximum capacity Upgrade, which is the Administrator's proposal, includes the completion of the DC Terminal Expansion Project and construction of the Intertie reinforcement facilities in the Northwest to interconnnect with the California/Oregon Transmission Project, thereby forming the Third AC Intertie. The Maximum Upgrade would increase Intertie capacity to 7,900 MW.

BPA estimates adding both upgrades to the system would have a moderate impact on total Intertie sales (619 to 708 aMW of additional sales in the years 1993-2003). (This assumes both upgrades are completed, adoption of the proposed IAP and the use of the upgrades to support long-term firm power sales.) The action could affect types of sales made, the parties involved in such sales, the operation of West Coast power systems, and the environment. As previously indicated, the net benefits of Maximum capacity would be $1,657 million based on use for additional economy energy sales and $1,976 million if used for additional firm sales contracts.

3/ Again, the difference in Third AC benefits ($289 million) with and without additional firm contracts, represents only that portion of the firm contracts benefits associated with sales enabled by the Third AC Interie.

Intertie Access Policy: Background

In the early 1980s, BPA determined it needed to alter its practice of allowing access to the Pacific Northwest portion of the Intertie because BPA found itself with an increased amount of Federal surplus and insufficient access to its own Intertie to make surplus sales. The agency was losing revenues from the foregone sales and jeopardizing its ability to repay the Treasury in a timely fashion. To remedy this situation, in September 1984, BPA adopted an Interim Intertie Access Policy to govern access by other utilities to BPA's portion of the Intertie. In June 1985, after completing an Environmental Assessment, BPA adopted a Near-Term Intertie Access Policy (NTIAP). The NTIAP established short-term procedures for granting Northwest scheduling utilities assured Intertie access for firm power sales to California and it also established mechanisms for scheduling Intertie capacity for nonfirm energy beyond the capacity required for firm power sales.

A lawsuit filed in the Ninth Circuit Court of Appeals challenging BPA's authority to adopt the Interim Near-Term policy was not successful. In April 1985, the Ninth Circuit ruled BPA should give itself preferential access to the Intertie, emphasizing BPA's statutory mandate that linked successful repayment of Treasury obligations with the agency's ability to raise adequate revenues.

In December 1987, BPA proposed a Long-Term Intertie Access Policy (LTIAP) which addresses both nonfirm and firm access to the Intertie as well as fish and wildlife and new resource development issues. Chapter 5 of this IDU EIS contains BPA's proposed Long-Term Intertie Access Policy.

Intertie Access Policy: Formula Allocation

The Proposed Formula Allocation contained in the IAP is the Administrator's proposal to allocate access to the Intertie for economy energy and nonfirm sales over the portion of the Intertie not required to support long-term sales. The Proposed Formula Allocation continues the formula allocation methodology used in the NTIAP.

Two alternatives for formula allocation are examined in this EIS. The first is the Pre-IAP Formula Allocation, whereby BPA would return to the practices governing the use of the Intertie before adoption of the Near-Term Intertie Access Policy. Access to the Intertie would be on a non-allocated basis. 4/ The second is the Hydro-First Formula Allocation, which would allocate access to declared surplus hydroelectric energy and capacity ahead of other resources. Under this alternative, remaining Intertie capacity would be allocated in proportion to BPA's and each utility's declared surplus from other than hydro sources.

4/ Under this procedure, BPA would first declare the amount of power it had to offer for sale and the price it would charge. Other utilities would then indicate the amounts and prices of their power. This placed BPA in the untenable position of being undercut by utilities making declarations subsequent to BPA's declaration.

Allocation would be made on a pro-rata basis to generating utilities in the Northwest, with any remaining capacity becoming available for extraregional utilities.

Intertie Access Policy: Assured Delivery

Under the Near-Term IAP, Northwest utilities were able to offer California utilities firm contracts for only the duration of the Near-Term IAP. BPA is examining this set of potential decisions that concern the amount of assured delivery to be offered to Northwest utilities to enable them to make long-term firm power sales. Allowing long-term assured deliveries by other Northwest utilities would reduce BPA's flexibility in its use of the Intertie. In addition, use of the Intertie for long-term firm sales has the potential for environmental effects that differ, in some respects, from those that would result in the absence of such sales.

Under the first alternative, Existing Contracts, the Intertie could be used primarily for short-term Intertie transactions (nonfirm energy sales and short-term firm power sales). This case includes a limited number of firm contracts that either were in place at the time this EIS was prepared or that BPA anticipated would be concluded and transmitted over the Intertie.

The second alternative, Federal Marketing, provides for long-term firm power sales by BPA over the Intertie to California. BPA could expect to receive higher prices for these kinds of transactions with California because the long-term sales would permit California to defer capital investment for new resources.

The third alternative, Assured Delivery, is the Administrator's proposal and is addressed as part of the IAP in Volume 1, Chapter 5 of this EIS. Under this alternative, BPA proposes to grant other utilities assured delivery for firm sales and seasonal exchanges based on each utility's average firm surplus. The projected benefits of the Intertie over the next 30 years, assuming Existing capacity, increase from $8,812 million to $9,797 million (a difference of $985 million) as a result of assuming additional firm sales are allowed under the IAP.

Extraregional Access

Extraregional utilities currently receive access to the Intertie only on an hourly allocation (nonfirm) basis or through contracts executed before the September 1984 implementation of the Interim Near-Term IAP. Access is granted only when there is unused capacity on the Intertie. Under BPA's proposal, extraregional utilities could receive greater access in exchange for increased participation in the Northwest's coordinated power system planning and operation. Any such action would require full environmental analysis and compliance with BPA procedures.

Access For New Resources

The NTIAP allows Intertie access only for existing resources. BPA's proposal seeks to prevent utilities from developing potentially harmful new resources in the future by restricting access for new resources to those required to support established Assured Delivery contracts. The EIS studies included a quantitative analysis of the effects of the proposed policy on new resource development in the Northwest and a qualitative analysis of expected impacts on resource development in California and the Inland Southwest. The results of those studies are summarized in the Environmental Impacts section below.

Access For Hydroelectric Resources

BPA's proposal includes provisions that reduce a utility's access to the Intertie for any new hydroelectric projects developed within "Protected Areas." Protected Areas are designated river reaches withdrawn from hydro development due to the presence of anadromous or high value resident fish, or wildlife. BPA has also designated areas where it has determined that investments in habitat, hatchery, passage or other projects may result in the presence of anadromous fish. BPA's Protected Area designations cover only the Columbia River Basin. The provisions also apply to any new capacity added to existing projects in Protected Areas. The EIS studies examined the effects of operational changes in the hydro system as a result of Intertie decisions on fish and wildlife resources. The results are summarized below.

Environmental Impacts

Description of Analysis

The analysis used for this EIS looked first at the potential effects of Intertie decisions on levels of power export sales by geographic region (British Columbia, Pacific Northwest, California and Inland Southwest) and then at how these sales would affect types and amounts of generation facilities operated throughout the study area. This information provides the foundation for the analysis of the effects of Intertie decisions on major environmental factors (e. g., air and water quality, consumption of nonrenewable resources and fisheries). The analysis first considers environmental effects from changes in operation of hydroelectric resources and then from changes in operation of thermal resources. There are also analyses of the anticipated effects of Intertie decisions on the need for new generation resources and a discussion of the economic aspects of proposed Intertie actions. Sensitivity analyses to test whether changes in some principal assumptions BPA made in performing the analysis would affect results to any significant degree were carried out as part of each of the environmental and economic studies.

Overall Conclusions

Intertie Expansion. Use of the expanded capacity of the Intertie is expected to have several small, but discernible environmental effects. Air pollutant concentrations would increase very slightly near Pacific

Northwest coal plants because Intertie expansion would result in an increase in the level of coal generation in the region. In California, purchases of Northwest energy would displace generation by more expensive oil and gas plants. Air quality would thus improve slightly in areas where the displaced plants are located as Intertie capacity is increased. In the Inland Southwest, there would be slight improvements in air quality as Intertie capacity increases due to some displacement of coal plants in that region. None of these effects is expected to be significant, however, since the magnitude of the projected changes in ambient air quality is very small.

Expanded capacity, if used at least in part for firm transactions, could enable power exchanges between the Northwest and California that could permit deferral of new resource construction in both regions.

Upgrading the Intertie would have small negative effects on anadromous fish stocks in the Northwest. Average decreases in stock survivals are projected to be less than 3 percent. Given anticipated increases in anadromous fish stocks resulting from planned improvements in fish passage facilities, these effects are not considered significant. If planned facilities for improving fish passage are foregone, even the small negative effects of increased capacity may be significant, since many stocks currently in a critical condition would remain in that status.

The increased capacity alternatives would have no significant effect on the spawning and emergence of salmonids in the Hanford Reach of the Columbia River or on resident fish production in Northwest streams or storage reservoirs.

As Intertie capacity increases, the amount of water consumed by closed-cycle power plants in the Northwest would increase, and water consumption would decrease at California and Inland Southwest plants. Changes in water consumption by Pacific Northwest, California, and Inland Southwest plants would generally not be significant. At California's Pittsburg and Contra Costa plants, significant problems with entrainment of aquatic life may be relieved slightly.

In British Columbia, upgrading the Intertie could slightly decrease available spawning and rearing habitat for resident fish species at Columbia River hydroelectric dams (particularly in the Duncan River and at Arrow Lakes Reservoir), but summer rearing habitat below Corra Linn Dam could increase. These effects in British Columbia would be more pronounced at larger Intertie capacity levels.

Intertie upgrades would have no appreciable effect on cultural resources, recreation, and irrigation. Expanded capacity, if used at least in part for firm transactions, could permit deferral of new resource construction (and associated capital investments and environment effects) in both regions.

Formula Allocation. The Proposed Formula Allocation option was found to have essentially the same effect on the environment as the Pre-IAP option. The Hydro-First option would mean a reduction in the total amount of export sales made over the Intertie because energy from coal plants cannot fill the Intertie completely during the portions of the year after hydro supplies are exhausted. The loss of sales amounts to less than 2 percent under the Pre-IAP Formula Allocation option. Under the Hydro-First option, hydro generation is 2 percent greater and coal generation 5 percent less than under the Pre-IAP option. The decline in PNW exports under the Hydro-First option would mean slightly greater operation of ISW resources. In California, the Hydro-First option results in slight increases in oil and gas generation (up to 3 percent) over levels occurring under the Pre-IAP option. Effects on other types of resources in California are negligible.

The Hydro-First option would result in slightly improved air quality after 1988 in the Northwest, but the change is not significant. In California and the Inland Southwest, there is very little difference in projected air quality among the formula allocation options.

BPA studies show no significant effects on spring migration flows in the Columbia and Snake Rivers under the Hydro-First option. The option is associated with both increases and decreases in expected anadromous fish stock survivals due to changes in spill and flow. However, these changes in survival are not significant. Analysis of impacts on successful coordination of flows to facilitate spawning, incubation, and emergence in the Hanford Reach show no adverse effects. The Hydro-First option would also not affect resident fish production.

Compared to the Pre-IAP option, both the Proposed Formula Allocation and the Hydro-First options would increase BPA revenues, but impacts on retail rates in the Northwest and California would be negligible.

Long-Term Firm Marketing. BPA's analysis found long-term firm power contracts would have a very small effect on levels of generation by existing and planned resources. In the Northwest, coal generation and associated air pollution would decline slightly in the early and mid-1990s. Operation of the hydro system would change only slightly.

The long-term firm contracts cases had no significant effect on juvenile anadromous fish survival. There were adverse impacts on resident fish in Hungry Horse reservoir as a result of changes in reservoir levels. The possibility of increased wave erosion of cultural resource sites, particularly at Libby Reservoir during the early years, was identified.

In California and the Inland Southwest, oil, gas, and coal generation would increase slightly to provide the Northwest with exchange energy in dry years in the Northwest, as called for in capacity/energy exchange contracts.

There was little difference among the long-term firm contracts cases with respect to effects on air quality in the Northwest. For California and the Inland Southwest, Assured Delivery shows slightly better projected air quality than either Existing Contracts or Federal Marketing after 1988, a consequence of an assumed firm sale which results in a net flow of Pacific Northwest power to California. Similarly, Assured Delivery would be the most likely of the long-term firm contracts cases to result in reductions of fish entrainment at California generating plants.

In the Northwest, at Existing Intertie capacity, the Federal Marketing cases are projected to result in savings of 85 MW of new resources by 2003, while Assured Delivery is projected to result in development of 131 MW of additional resources.

Long-term firm transactions are also expected to lead to resource savings in California because California utilities would be able to plan on power from the Northwest even in low Northwest water years.

Environmental Impacts-Summary of Specific Findings

Power Systems Effects. The EIS studies predict that the largest and most consistent effect of Intertie decisions on Intertie sales from the Northwest and Canada would result from Intertie upgrades. Intertie sales would increase by about 312 aMW with the DC Upgrade and by about 448 aMW with the Third AC/COTP upgrade. The Maximum Upgrade would lead to fewer sales than the sum of the effect of each upgrade alone: the Maximum Upgrade would lead to about 619 aMW more Intertie sales compared to Existing capacity.

Intertie policy decisions would have a smaller and less consistent effect. The formula allocation alternatives for short-term transactions would in some cases result in small positive, and in other cases, small negative impacts on Intertie sales. Similarly, long-term firm power transactions would not greatly affect the annual average level of Intertie sales, although long-term firm contracts would be valuable because they would reduce the cost of resource acquisitions in both the Northwest and California and lead to a higher price for Northwest sales.

Intertie capacity alternatives also have the largest and most consistent effect on generation levels in each region. As Intertie capacity increases, the Northwest and Canada increase sales through greater generation by hydro resources and, in the Northwest, by coal plants. In California, increased imports from the Northwest and Canada allow greater displacement of more expensive resources, primarily oil and gas plants. If California imports more from the north, it would import less from the Inland Southwest, allowing coal generation to be curtailed in the Southwest.

Formula allocation and long-term firm marketing decisions have generally smaller effects on the mix of generating resources used to meet load in each region. Of these cases, the Hydro-First Formula Allocation has the largest effect. It would generally lead to more hydro generation and less coal generation in the Northwest. Total Intertie sales from the Northwest would be somewhat lower, so displacement of higher cost resources in California and the Southwest would be slightly less.

Effects on the Hydroelectric System. Increasing Intertie capacity has little effect on reservoir elevations or refill probabilities. Under the DC Terminal expansion alternative, about 100 to 150 aMW of spill would be converted to generation, and a similar conversion of 200 to 250 aMW would take place under Maximum Capacity.

The Pre-IAP and Proposed Formula Allocation alternatives differ little in their effects on reservoir elevations, refill probability or overgeneration. The Hydro-First alternative results in slightly lower reservoir elevations and slightly less overgeneration than the other alternatives.

Changes in long-term firm contracts actions have relatively substantial effects on reservoir elevations. Differences in reservoir levels between the Existing Contracts condition and the other firm contracts alternatives were varied in different months and years. The greatest differences in magnitude occur in fall and winter months. Results for the Federal Marketing and Assured Delivery alternatives are similar, although the Assured Delivery cases have somewhat higher reservoir levels in 1988 and 1993. The results are the same for all Intertie sizes and formula allocation alternatives. Reservoir levels are generally lower for Existing Contracts than the other firm contract cases in 1988. The only reservoir potentially affected by short-term changes due to Intertie decisions is Grand Coulee.

Long-term firm contract actions result in some variation in overgeneration amounts, but changes from the Existing Contracts case are less than 10 percent.

Fish

The EIS studies found there would be no adverse impacts on resident fish in streams as a result of Intertie decisions. The only resident fish in major reservoirs that could experience adverse impacts are those residing in Hungry Horse Reservoir. Reservoir elevation changes are minor at Grand Coulee, Albeni Falls, Libby and Dworshak. The impacts at Hungry Horse result from increased levels of firm marketing. Reservoir elevations under these options are predicted to decrease by an average of approximately 4 to 5 feet during some fall months, affecting food supply and growth of resident fish. Research comparing Hungry Horse fish production to reservoir operations is being completed pursuant to the Power Planning Council's Fish and Wildlife Program and will be used to determine the need for and, if necessary, the nature of appropriate mitigation.

The formula allocation options studied are projected to have negligible effects on survival of juvenile anadromous fish during thier downstream migration. The long-term firm contracts options studied showed minor impacts on the downstream migration of anadromous fish relative to each stock's current population, productivity status, current smolt passage survival rates and expected increase in survival due to planned improvements in fish passage facilities. However, for Methow River spring chinook, a potentially critical stock, a conclusion of nonsignificance is dependent upon the construction of planned mid-Columbia bypass systems.

Increases in Intertie capacity would have more adverse effect upon anadromous fish survival than would either the formula allocation or firm contracts options. However, even these effects are small and would not be expected to be significant, provided planned fish passage improvements are made.
If planned bypass improvements are not constructed, even the relatively small adverse effects of increased capacity could become significant for a number of stocks.

Recreation, Irrigation and Cultural Resources. Intertie decisions are unlikely to affect recreation or irrigation in the Northwest. Reservoir levels during summer months when recreation usually occurs are only minimally affected by any of the alternatives. In fall and winter, however, long-term firm contracts may change reservoir levels, thus potentially affecting cultural resources. Erosion of cultural resource sites at Libby Reservoir could be a particular problem as a result of long-term firm power contracts alternatives.

Intertie decisions are not expected to result in significant effects on wildlife or vegetation.

Thermal Operations. In the Northwest and Inland Southwest, Intertie capacity decisions have the greatest effect on the consumption of coal. As capacity increases, coal generation, consumption and associated land disturbance increase in the Northwest and decrease in the Inland Southwest. Alternative formula allocation options have almost no impact on the relative amounts of coal consumed.

As for long-term firm marketing, both Federal Marketing and Assured Delivery firm sales conditions generally reduce coal use at Northwest coal plants, except for 1988 with the Existing Intertie. In the Inland Southwest, less regular changes in coal consumption occur as firm sales conditions change. In California, increased Intertie capacity results in decreased consumption of oil and gas, but the use of these fuels is not significantly affected by either changes in formula allocation options or firm contracts conditions. British Columbia is not expected to alter its consumption of nonrenewable resources in response to Intertie decisions, unless the proposed Site C dam is built.

The EIS studies show that Intertie capacity decisions would have the greatest effect on the net consumption of oil and gas in California in 1993 as increased sales from the Northwest displace the use of oil and gas generation. Total coal consumption, Inland Southwest plus Pacific Northwest, is reduced in 1993 with Maximum Intertie capacity as more Inland Southwest coal-fired generation is displaced than Pacific Northwest coal-fired generation is increased. The difference is made up by increased Pacific Northwest hydro generation.

Impacts of the formula allocation and long-term firm contracts cases on the use of oil and gas for electricity generation are small. After 1988, the Federal Marketing and Assured Delivery contracts cases would generally lead to decreases in coal consumption in the Northwest. Decreases for Assured Delivery are of greater magnitude.

Air Quality. All ambient air quality changes due to changes in Intertie capacity, formula allocation decisions and long-term firm marketing decisions are projected to be small, less than Class II Prevention of Significant Deterioration (PSD) increments for Total Suspended Particulate and sulfur dioxide, as established by EPA. Increasing Intertie capacity would lead to only small increases in air pollution from coal plants in the Northwest and would allow generation from California plants to be reduced, thus improving ambient air quality by small amounts in heavily populated areas near plants in California. Air quality in the Inland Southwest would also be improved slightly because of lower demand for power from plants there.

The DC Terminal Expansion would primarily displace power generation from oil and gas plants located in densely populated areas in the Los Angeles air basin. The Third AC would primarily reduce air pollution in the northern and central areas of California, compared to conditions under Existing Intertie capacity. Although some Northwest energy transmitted over the Third AC would indirectly serve southern California, overall there would be less oil and gas displacement in densely populated areas of southern California. Under Maximum capacity, the benefits of increased Intertie sales would be spread more evenly across California.

The Hydro-First Formula Allocation option has some minor benefits for air quality in the Northwest relative to the Proposed and Pre-IAP options for 1993 through 2003. For California and the Inland Southwest, the choice of formula allocation appears to have very little effect on projected air quality.

The level of long-term firm contracts has little effect on air quality in the Northwest. After 1988, air quality in California and the Inland Southwest is projected to be better under Assured Delivery than under Federal Marketing or Existing Contracts, assuming a firm energy sale to California under Assured Delivery in addition to exchanges.

Water Use and Fish. The EIS studies showed that none of the Intertie decisions had significant impacts on water resources use and consumption at thermal plants in the study area.

Vegetation and Wildlife. The main effects of thermal operations changes resulting from Intertie decisions on vegetation and wildlife involve air quality changes from coal plants, land use changes from coal mining and potential spills from oil-fired plants. To the extent Intertie decisions delay coal mine development, they could have a beneficial effect on vegetation and wildlife. Federal and state environmental regulations are expected to provide sufficient protection for vegetation and wildlife, making adverse effects likely only from poorly operated facilities or accidental spills.

New Resources. In general, the liberal granting of firm access to the Intertie for new resources significantly encourages resource development in the Northwest and would allow resource deferrals in California and the Inland Southwest. The amount of effect and types of resources developed depend on the nature of assumed firm contracts. Intertie capacity decisions have little impact on resource development.

Capacity/energy exchange contracts tend to slow resource development in all regions, while power sales from the Northwest tend to increase Northwest resource development, but slow resource development in the Inland Southwest and California. Scenarios that feature BPA as a primary developer of new resources place less emphasis on coal development due to the potential for completing Washington Nuclear Plants 1 and 3. Scenarios in which utilities other than BPA bear major responsibility for resource development emphasize the construction of coal and hydro plants.

Economic Impacts. In the economic analysis, the net benefit of Interties to the Pacific Northwest, California and BC Hydro represents the savings of displacing California resources with economy energy minus Pacific Northwest and BC Hydro production costs and Intertie construction costs.

The analysis shows the DC Terminal Expansion to be cost effective in all cases studied. The net benefit, assuming adoption of the proposed IAP but no addition of new firm contracts, is $996 million (1987 net present value (NPV) dollars). The sensitivity analyses show the net benefit to range from $113 million to $2.6 billion.

The proposed Third AC/COTP is cost effective in all but two cases. The net benefit, again assuming adoption of the proposed IAP but no addition of new firm sales, is $661 million NPV. The sensitivity analyses show the net benefit to range from $-388 million to $2.8 billion.

The net benefit of the Maximum Upgrade, given the same assumptions as stated for the DC and Third AC cases, is $1,657 million. The sensitivity analyses show the net benefit to range from $-274 million to $5.4 billion.

The economic analysis defined the net benefit of Intertie access formula allocation policies to the Pacific Northwest, California and BC Hydro to be the savings of displacing California resources with economy energy minus Pacific Northwest and BC Hydro production costs. The net benefit of the Proposed Formula Allocation relative to the Pre-IAP is slightly negative in all cases, ranging from $-50 million to $-41 million NPV (depending on contract and capacity assumptions). This is small in comparison to the total benefit of the Interties (including existing system benefits) of approximately $15 billion. The net benefit of the Hydro-First option relative to the Pre-IAP option is also negative in all cases, ranging from $-36 million to $-20 million.

The economic analysis defined the net benefit of long-term firm contracts to the Pacific Northwest, California and BC Hydro to be the net savings of displacing California resources with firm contracts rather than economy energy, plus California resource deferral savings, plus/minus Pacific Northwest resource deferral/acquisition, minus Pacific Northwest and BC Hydro production costs.

The Federal Marketing case includes 1,550 MW of firm contracts above the Existing Contracts for the Existing Intertie and 2,150 MW for Maximum capacity. Under the Proposed Formula Allocation, the net benefit of the contracts is $557 million and $691 million NPV for the Existing Intertie and Maximum capacity, respectively.

The Assured Delivery case includes an additional 400 MW of firm contracts above the Federal Marketing contracts. With the additional 400 MW of firm contracts, the net benefit of the contracts increases to $651 million NPV for the Existing Intertie and $819 million for Maximum capacity, compared to the Existing Contracts case.

Irreversible and Irretrievable Commitments of Resources. The proposed actions would not be expected to result in irreversible or irretrievable commitments of resources. In fact, the proposed actions would be expected to result in conservation of fossil and nuclear fuels and would minimize land use and monetary investments needed to meet power requirements throughout the Western United States. No unavoidable adverse effects that are incapable of mitigation are projected to occur as a result of the proposed actions. BPA has included mitigative measures to address adverse effects on resident fish and cultural resources as a part of the proposed actions. The proposed actions would facilitate enhanced use of environmental resources for the purposes of interregional sales and transfer of electrical power. Because of the nature of the proposed actions, the maintenance and enhancement of long term productivity will not be affected by short term uses.

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PURPOSE OF AND NEED FOR ACTION

Chapter 1

PURPOSE OF AND NEED FOR ACTION

1.1 INTRODUCTION

The need for the proposed Bonneville Power Administration (BPA) actions is to enable short- and long-term contractual sales and transfers of Federal power surplus to the Administrator's requirements for Pacific Northwest (PNW) loads, and to manage other interregional transfers of surplus power between the PNW and California over the BPA-controlled portion of the Pacific Northwest/ Pacific Southwest Intertie (Intertie).

These actions may include: (1) expansion of Intertie capacity; (2) adoption of a Long-Term Intertie Access Policy (LTIAP) 1/ that will address short-term and long-term transmission of non-Federal power on the Intertie; and (3) decisions on long-term firm power contracts under which power could be marketed over the Intertie.

The purposes of expanding Intertie capacity are to:

- Enhance economic and operational efficiency;
- Support acceptable environmental quality;
- Increase system flexibility and reliability;
- Increase the ability to deliver surplus power during times when the surplus is most valuable to the importing region; and
- Achieve consistency with other national environmental policies. 2/

1/ All references to analyses of the effects of BPA's LTIAP in this EIS are intended to refer to the proposed LTIAP as contained in Chapter 5 of the IDU Final EIS. This proposed LTIAP may be modified prior to implementation. The Final LTIAP will be addressed in the Administrator's Record of Decision.

2/ Consistency with applicable national environmental policies includes conformance to Acts and regulations governing the following: noise; air and water quality; protection of archeological and historic resources and of endangered and threatened species of plants and animals; management and protection of floodplains and wetlands, National Trails System, and Wild and Scenic Rivers; contract compliance; use and disposal of insecticides, herbicides, fungicides, rodenticides, and toxic and hazardous wastes; right-of-way on public land; discharges into waters; structures in navigable waters; resource conservation and recovery; energy conservation; consistency with intergovernmental plans and programs. Also applicable are regulations of the Council on Environmental Quality as developed from the National Environmental Policy Act (NEPA).

The purposes the BPA Administrator will consider in developing the Intertie Access Policy are to:

- Enhance BPA's ability to repay the U.S. Treasury for the Federal investment in a timely manner;
- Support acceptable environmental quality;
- Support the Administrator's ability to maintain reasonable power rates for BPA's wholesale customers in the Pacific Northwest;
- Equitably allocate access to Intertie capacity in excess of that which the Administrator determines is required for BPA use in a manner which reasonably balances BPA's statutory obligations with impacts on competition;
- Provide an opportunity for long-term assured access to enable long-term firm power or firm capacity transactions; and
- Achieve consistency with other national environmental policies.

The BPA Administrator must decide:

- Whether to participate in the development of additional capacity of the Pacific Northwest/Pacific Southwest Intertie;
- How to allocate access to the Intertie for economy energy sales;
- How to establish access to support firm power sales and exchanges for utilities other than BPA;
- How much and what kind of access should be allowed for new resources;
- Whether to limit hydroelectric power access to the Intertie when it would interfere with the Administrator's efforts to protect fish and wildlife; and
- Whether and how to allow access to the Intertie for extraregional utilities.

This chapter provides background on BPA's statutory responsibilities and its customers. It describes the existing Intertie system, why it was built, and who owns it. Then the chapter looks at the status of several proposals to expand the Intertie. The first is the DC Terminal Expansion Project. Next, the Third AC/California/Oregon Transmission Project (Third AC/COTP) is described. The effects of operating either or both of these projects are studied in this Intertie Development and Use (IDU) Environmental Impact Statement (EIS). Finally, a proposal for an Inland Intertie is mentioned, but the proposal is too preliminary for further consideration in the EIS.

The next part of the chapter deals with the development of BPA's Near-Term Intertie Access Policy, the reasons BPA put it into effect, the agency's authority to do so, the contents of that policy, and an unsuccessful court challenges of the policy.

The agency's proposed Long-Term Intertie Access Policy (LTIAP), which is one of the main subjects of the IDU EIS, is discussed briefly. The proposed policy itself can be found in Chapter 5. This chapter provides some background on the scoping of the environmental analysis for the policy. The IDU EIS addresses environmental issues raised by the proposed Intertie Access Policy and its alternatives and the environmental effects of other Intertie-related actions, including the DC Terminal Expansion Project, the Third AC/COTP Project and long-term firm marketing over the Intertie.

The final part of this chapter mentions British Columbia's proposed Site C dam project, which at this time is too preliminary to be included in this document.

1.1.1 BPA'S ROLE AS A POWER MARKETING AGENCY

The Bonneville Project Act of 1937 (Project Act) established BPA as the marketing agent for power produced by the Bonneville Dam (16 U.S.C. §832a(a)). Through subsequent delegations within the Executive Branch and ultimately through statute, BPA has been given the additional responsibility to market power from 31 Federal dams in the Columbia River basin and certain thermal resources (16 U.S.C. §§838f and 839a(10)). Today, BPA is the largest power marketing agency within the Department of Energy. Congress has defined BPA's primary marketing area as the PNW Region, encompassing the States of Washington, Oregon, and Idaho, as well as the State of Montana west of the Continental Divide and certain other border areas (16 U.S.C §839a(14)). (See Figure 1.1.)

1.1.2 BPA'S CUSTOMERS

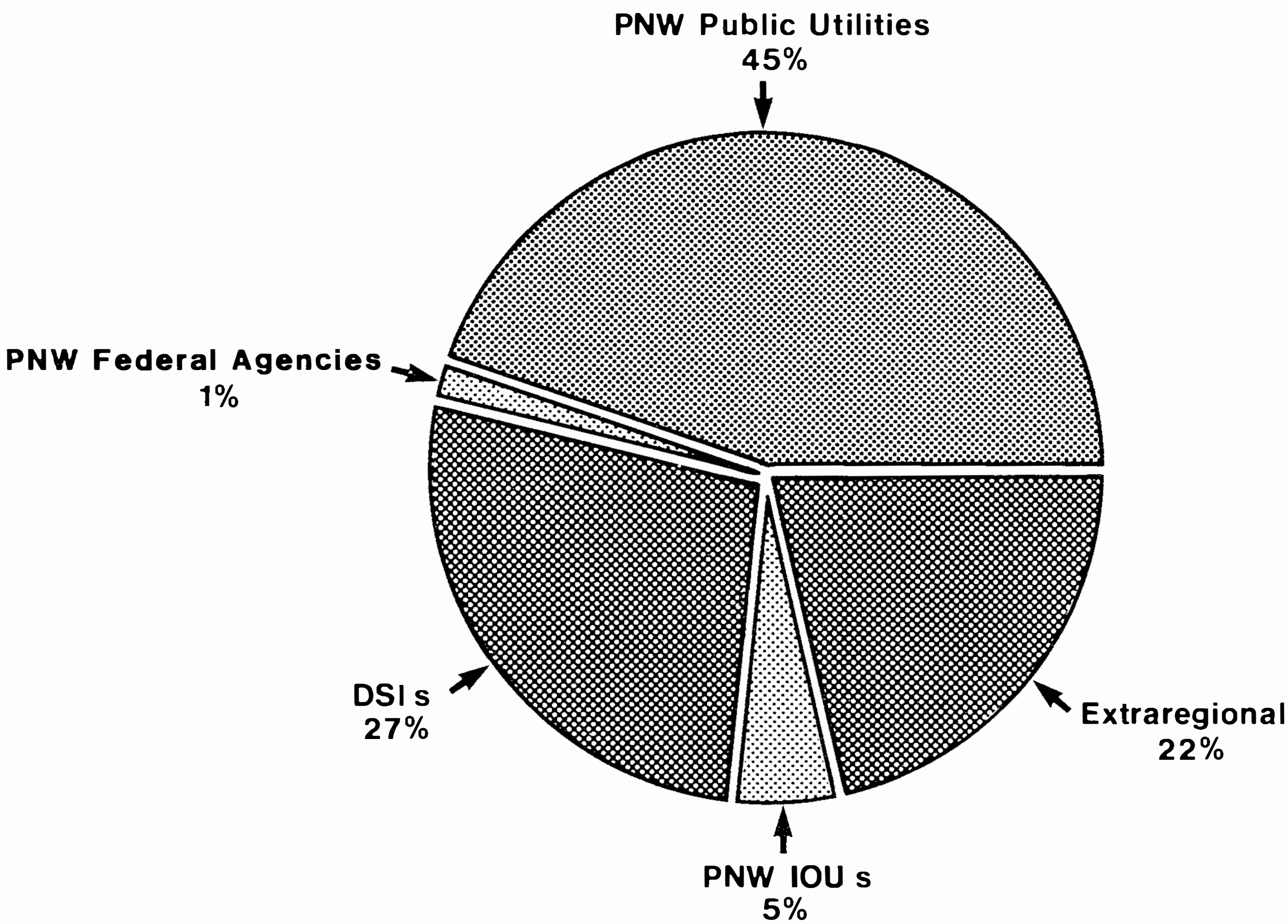
BPA markets wholesale electric power to several customer groups inside and outside the region (see Figure 1.2) under various rate schedules. Within the region, BPA customers include four groups. The first are public bodies and cooperatives known as "preference" customers. Under the Project Act and the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), preference customers enjoy a statutory priority for available power, including BPA's surplus power. The second regional customer group is the direct-service industries (DSIs). DSIs are large industries that purchase power directly from BPA rather than from a utility. The Pacific Northwest Power Act gave the DSIs rights to initial, 20-year power contracts, and authorized BPA to offer additional, follow-on contracts as prescribed by law; however, the DSIs do not have preference status. The third regional customer group is the investor-owned utilities (IOUs). IOUs are "nonpreference" customers. However, the Pacific Northwest Power Act requires BPA to serve the load growth of IOUs upon request with minimum notice as required under the power sales contracts. Finally, BPA is authorized, but not required, to serve the needs of a fourth customer group, Federal agencies.

FIGURE 1.1

BPA SERVICE AREA

FIGURE 1.2

BPA SALES BY CUSTOMER CLASS
FY '85



BPA also sells power outside the PNW region to public bodies, Federal agencies, and IOUs, primarily in California.

BPA's extraregional sales are subject to restrictions that provide a geographic preference favoring sale of BPA power in the Pacific Northwest. The Pacific Northwest Preference Act of 1964 (Preference Act, 16 U.S.C. §837) and the Pacific Northwest Power Act (16 U.S.C. §839) require that BPA first offer its available power to PNW customers. Consequently, BPA may sell outside the region only that amount of power that is surplus to PNW needs. Publicly owned entities outside the region have preference over IOUs outside the region for BPA surplus power. (More detail on the requirements of these Acts is found later in this chapter.)

1.2 EXPANSION OF INTERTIE CAPACITY

1.2.1 DESCRIPTION OF THE EXISTING INTERTIE SYSTEM

Since its completion in 1968, the Intertie has served as the principal means for transmitting firm and nonfirm energy and capacity between the Pacific Northwest and California. The following discussions address Congressional intent in authorizing construction of the Intertie, the nature of the physical facilities that make up the Intertie, and current ownership of existing Intertie facilities.

In authorizing the building of an Intertie system, Congress focused on two objectives: 1/

- To provide an additional market for BPA power to enable BPA to increase its revenue and therefore repay the U.S. Treasury in a timely manner. BPA owes the Federal government a significant sum for the original construction of the Federal dams and transmission system in the Pacific Northwest. By enabling the transmission to California of surplus power generated from water that would otherwise be spilled for lack of a market, BPA can obtain additional revenue and repay the Federal Government in a timely manner.

- To make more efficient use of resources in the Pacific Northwest and California. The Intertie can be used to send power in either direction. When the PNW has surplus power during summer months, power generally can be sold to California more cheaply than Californians could operate their thermal generation plants. When the PNW has "peak" needs in winter for heating, and California loads are lower, power can be purchased by the PNW from California. Existing resources can be used more efficiently, and both regions can avoid building extra plants just to meet peak loads at some times of the year.

1/ 16 U.S.C. §837 (Northwest Preference Act) (1964). See also Los Angeles Department of Water and Power v. Bonneville Power Administration, 759 F.2d 684 (Ninth Circuit, 1985)

In the Pacific Northwest, the Pacific Northwest/Pacific Southwest Intertie currently consists of several high-voltage transmission lines; two 500-kilovolt (kV) alternating-current lines and one 1,000-kV direct-current line (see Figure 1.3). BPA also uses a portion of its 500-kV Buckley-Summer Lake line and its contractual rights in Pacific Power & Light's Summer Lake-Malin Line for Intertie transactions.

The alternating current (AC) lines extend about 945 miles from John Day Substation near John Day Dam on the Columbia River in Oregon to the Lugo Substation near Los Angeles. They interconnect with other transmission lines at eight points. The 846-mile direct-current (DC) line runs from the Celilo Station near The Dalles Dam in Oregon to the Sylmar Station near Los Angeles. The line transmits power directly between the PNW and Southern California.

The present physical capability of the three Intertie lines is approximately 5,200 MW--about 3,200 MW on the AC lines and 2,000 MW on the DC line. However, the DC Terminal Expansion Project, currently in progress, will increase DC capacity by approximately 1,100 MW by upgrading the terminals at either end of the DC Intertie. The Third AC/California-Oregon Transmission Project (COTP), which would upgrade the AC Intertie capacity to approximately 4,800 MW, has been proposed by California utilities and the Western Area Power Administration (Western). Both the DC Terminal Expansion Project and the Third AC/COTP are described in Section 1.2.2, Intertie Expansions, later in this chapter.

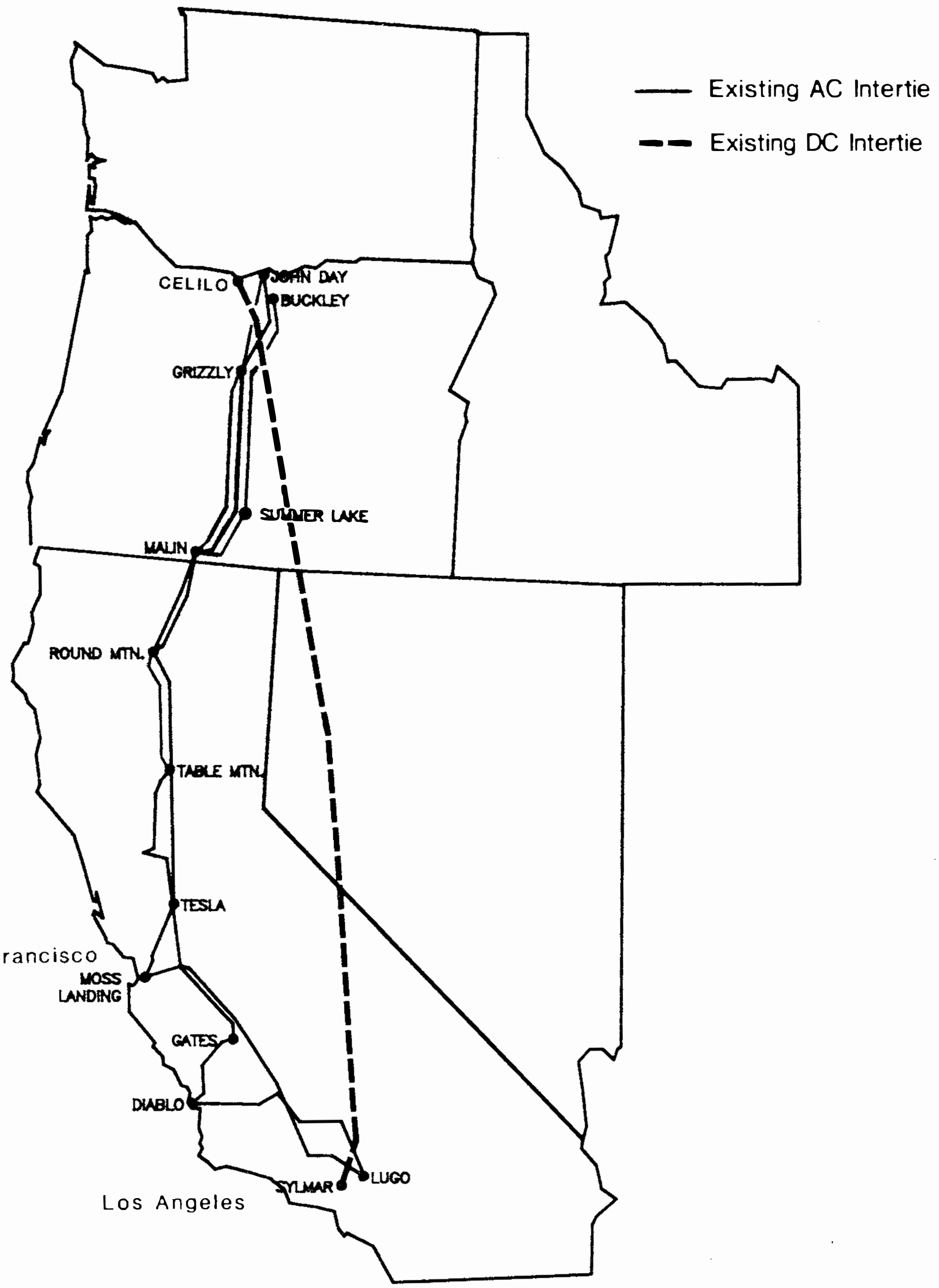
Facilities of the AC Intertie north of Malin Substation are owned by BPA and Portland General Electric Company (PGE). BPA owns both AC lines from John Day to Grizzly in central Oregon, as well as the Grizzly-Malin No. 1 line. PGE owns the Grizzly-Malin No. 2 line. Contractually, PGE and BPA have exchanged rights on each other's lines until December 31, 1988. As a result, PGE has contractual rights to 25 percent and BPA has contractual rights to 75 percent of the capacity resulting from the two AC Intertie lines north of Malin Substation. Pacific Power & Light Company (PP&L) owns some facilities at Malin Substation and south of Malin, and also gained certain access rights to Malin Substation over its Midpoint (Wyoming) - Malin Line for sales to California under the 1979 Midpoint-Malin Agreement with BPA and the 1986 agreement between PP&L and BPA. Western also owns some facilities at the Malin Substation.

Capacity entitlements south of Malin Substation are divided among private and public utilities and Western.

If the AC portion of the Intertie is upgraded, the relative shares of AC Intertie capacity owned by BPA and by other utilities may change, as discussed below.

Figure 1.3

Existing Intertie System



1.2.2 INTERTIE EXPANSIONS

In addition to the added capacity that will result from construction of the DC Terminal Expansion Project, several other possibilities are being proposed or considered, some of which could be completed during the term of the contracts adopted under the Long-Term Intertie Access Policy, and may affect the operation and impacts of the Intertie.

Although the BPA Administrator decided in August 1986 to proceed with the construction of the DC Terminal Expansion Project, decisions concerning operation of the project will await completion of the IDU EIS. The decision to construct the DC Terminal Expansion Project is covered by its own environmental documents: an Environmental Assessment (February 1985), and a Supplemental Environmental Assessment (July 1986). On August 29, 1986, DOE issued a Finding of No Significant Impact on the Project, and the Administrator signed an Administrative Record of Decision on October 4, 1986. These Assessments cover the construction actions and impacts of upgrading DC capacity by approximately 1,100 MW (to 3,100 MW) without constructing additional lines. This can be accomplished by expanding the stations that convert AC current to DC current (and vice versa). These stations are located at Sylmar, near Los Angeles, and Celilo near The Dalles Dam in Oregon.

The decision to construct the DC Upgrade was challenged in Court by the State of Idaho and others. Subsequently, the Ninth Circuit Court of Appeals ordered BPA to prepare an EIS on the project and its relationship to other Intertie actions. The Administrator has promised to complete the IDU EIS before making decisions regarding operation of the Terminal Expansion Project.

The proposed California-Oregon Transmission Project (COTP) is the result of a July 1984 authorization from Congress to the Secretary of Energy authorizing participation in the construction of a Third AC Intertie line between California and the Pacific Northwest (PL 98-360). Participants include the Western Area Power Administration (Western), the Transmission Agency of Northern California (TANC--a joint power agency consisting of 15 municipalities, public utility districts, and irrigation districts), 6 southern California municipalities, and three California investor-owned utilities (Pacific Gas & Electric Company (PG&E); Southern California Edison (SCE); and San Diego Gas & Electric (SDG&E)) and 6 additional public entities. The California Department of Water Resources has an option to participate. These entities have prepared a joint (i.e., a single document) Environmental Impact Statement (under the National Environmental Policy Act) and Environmental Impact Report (under the California Environmental Quality Act) on the effects of the proposed actions. The COTP document addresses economic impacts in California and the impacts of constructing, operating, and maintaining the line. The effects of changes in West Coast resource operation occasioned by the expanded capacity are addressed in this IDU EIS, a summary of which was included in both the draft and final COTP EIS/EIR.

Although BPA will make no decision that will directly impact the siting decision of the COTP facilities in California, BPA and the COTP must reach agreement on a point of interconnection between the COTP and the PNW system. Decisions by the COTP participants about costs, operation, and maintenance of the project will be based on the following: the environmental impacts of line construction, operation and maintenance, as discussed in the COTP EIS; effects of changes in resource operation as a result of the COTP, as discussed in the IDU EIS; and the economic benefits available through commercial transactions between the Pacific Northwest and California.

The Third AC/COTP would increase the capacity of the AC Intertie in California to approximately 4,800 MW. With minor modifications, facilities in the Pacific Northwest are capable of delivering approximately 4000 MW to California. Additional facility construction in Oregon, including line and substation work, would increase the transfer capacity of the Oregon AC Intertie facilities to about 4,800 MW, to equal the capacity of the upgraded California AC facilities. BPA is currently evaluating options for possible participation by Pacific Northwest utilities in the northern portion of the Third AC Intertie through a leasing or ownership arrangement. If this process leads to a proposal to include non-Federal participants, the proposal would require its own environmental analysis and review.

An additional Intertie upgrade option is in the very early stages of discussion. In January 1985, Western issued a report, Completing the Intertie, which examined seven alternatives for the construction of additional DC Intertie capacity by the early 1990s. The concept of "completing" the Intertie derives from the fact that Congress originally authorized construction of two DC lines, only one of which has been built. The three alternatives evaluated as the most technically feasible include the construction of a new DC line from the Columbia River in Oregon to Mead, Nevada, joining a DC transmission Intertie from Phoenix to Los Angeles; a new DC line from southern Idaho to join the Phoenix-Los Angeles cross-tie; and the Phoenix-Los Angeles cross-tie alone.

In September 1984, the Arizona Public Service Company and the Intercompany Pool (an association of Pacific Northwest IOUs) issued a study examining a variation of one of the Second DC alternative corridors. This document, The Inland Intertie Northwest-Desert Southwest Regional Capacity/Energy Diversity Exchange Study, proposes construction of a new Intertie, probably from Idaho to the Mead, Nevada area, by the late 1990s. This Inland Intertie would enable capacity/energy diversity exchanges between the PNW and the Southwest. A subsequent study by a larger group of interested parties was released in July 1987 outlining options for locating a line.

The Inland Intertie options have not matured to the level of a formal proposal and are too speculative at this time to be examined further in this EIS.

1.3 DEVELOPMENT OF NEAR-TERM INTERTIE ACCESS POLICY

1.3.1 BACKGROUND: INTERTIE ACCESS PRACTICES BEFORE SEPTEMBER 1984

Since the Intertie began operation in 1968, BPA has allowed many entities to have access to the PNW portion of the Intertie. Both regional and extraregional scheduling utilities, such as British Columbia Hydro and Power Authority (BC Hydro), were permitted to share BPA-owned Intertie capacity, based on whose energy was purchased by California buyers. When PNW energy available for export to California exceeded either the available Intertie capacity or California demand, the Exportable Agreement governed access (see BPA, Near-Term Intertie Access Policy, Administrator's Record of Decision (Near-Term IAP ROD), September, 1984).

The Exportable Agreement, signed by BPA and 14 PNW generating utilities on January 1, 1969, is designed to respond to conditions when more nonfirm power is available from generators in the Northwest than can be transmitted to California purchasers. The Agreement (BPA Contract No. 14-03-73155) aims to ensure BPA's access to the market and to share BPA's California market with other Pacific Northwest generators when surplus energy in the PNW brings the system close to spilling water. The Agreement, in effect until January 1, 1989, can briefly be described as a method to prorate the sales to California among the Exportable Agreement signatories on the basis of the ratio (during each hour) of each party's declared surplus nonfirm energy to the total available PNW surplus nonfirm energy. No extraregional utilities are signatories to the Agreement. When the Agreement is in effect, access to the Intertie is provided only to parties to the Agreement.

Because BPA's portion of the total surplus nonfirm energy generally is large, the Exportable Agreement carries out Congressional intent that BPA use the Intertie to sell a large portion of its available supply. However, the Agreement also provides some access for non-Federal parties. Any party may declare the amount of surplus it is willing to sell at BPA's "applicable rate" 1/ and obtain an "apportionment" of exportable energy. That party's apportionment is usually purchased by BPA. BPA then sells it as Federal energy to California utilities under BPA's existing power sales contracts. The non-Federal party receives credit at the rate at which BPA sold the power to California. An alternate arrangement, under section 5(c) of the Exportable Agreement, allows all or part of an apportioned share of power to be sold directly to a specific California entity at a price other than the applicable rate, although the initial apportionment is calculated on the assumption that the applicable rate would apply.

1/ BPA's ratemaking process establishes the "applicable rate" to be applied to sales under the Exportable Agreement (see Near-Term IAP ROD, p. 42).

1.3.2 REASONS FOR DEVELOPMENT OF NEAR-TERM INTERTIE ACCESS POLICY

In recent years, BPA has found that it was being adversely affected by competitive conditions when the Exportable Agreement was not in effect. In addition, the power supply conditions in the region changed. The Pacific Northwest moved from forecasted deficits to large surpluses. The growth rate of electric power loads declined as the region suffered an economic recession early in the 1980s. At the same time, the region experienced higher-than-average water years.

Increased demand from regional and extraregional utilities for additional access to the Intertie to sell surplus power hampered BPA's ability to dispose of its own power and repay the Treasury in a timely fashion. Cumulatively, these circumstances led to BPA's having more Federal surplus available for sale and less access to its own Intertie than it required. In addition, during heavy runoff months, California buyers would purchase from PNW utilities (who could slightly under cut BPA's offered price because under the Northwest Preference Act, BPA is required to publicly announce its price, unlike its competitors) rather than from BPA, forcing BPA into the Exportable Agreement. This resulted in BPA selling its power at extremely low rates, leading to an unreasonable cost burden for BPA's PNW ratepayers. 1/

The existence of regional firm power surpluses also made firm sales of surplus power to California possible and attractive to regional and extraregional utilities. Consequently, BPA received requests for firm transmission service for such transactions. For many years, BPA had not agreed to any new firm transmission contracts for use of the Intertie because BPA was reluctant to adversely affect sales of nonfirm surplus over the Intertie (e.g., by setting aside Intertie capacity for guaranteed firm sales). Consequently, the development of a market for surplus firm power was handicapped.

BPA's inability to sell its own power over its own Intertie, at appropriate rates, contributed to an increasing financial strain on the agency. A key Congressional purpose in constructing the Intertie had been to insure that BPA would have a market for surplus power, and that surplus power revenue would enhance BPA's ability to repay the Federal investment in the BPA system in a timely manner, while allowing BPA to charge the lowest possible rates to consumers consistent with sound business practices. BPA's Intertie practices were frustrating its ability to satisfy this Congressional purpose. Therefore, BPA determined that it needed a comprehensive Intertie Access Policy that would assure its ability to meet the Congressional mandate.

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* The financial strain on BPA as a result of these Intertie practices was described and documented in Near-Term IAP ROD; BPA, Environmental Assessment, Proposed Near-Term Intertie Access Policy, February 1985; and BPA, Near-Term Intertie Access Policy, Administrator's Record of Decision, May 1985.

In the summer of 1983, BPA's Administrator began to explore the development of an Intertie Access Policy to enhance BPA's power marketing efforts and ability to recover revenues, and to provide certainty with respect to BPA's and others' firm and nonfirm transactions. In September 1984, BPA put an Intertim Near-Term IAP into effect. In June 1985, BPA adopted a Near-Term IAP which continues in effect until a Long-Term IAP is finally adopted.

1.3.3 ADMINISTRATOR'S AUTHORITY TO DEVELOP INTERTIE ACCESS POLICY

By marketing surplus Federal power outside the PNW region, BPA receives revenues from power that might otherwise be wasted under current planning methods. BPA thereby enhances its ability to recover the costs of operating the Federal system in the PNW, including the amortization of the Federal investment in the Federal Columbia River Power System. In this way, BPA implements its broad statutory authority to recover its costs fully and to provide the lowest possible rates to consumers, consistent with sound business principles. (16 U.S.C. §§832f, 838g, 839, and 839e(a)(1).)

The Pacific Northwest Preference Act authorized the BPA Administrator to make first use of Federal Intertie lines to carry Federal surplus power to California. Only after BPA's needs are met must any excess Intertie capacity be made available to non-Federal entities (16 U.S.C. §837(e)). Congress reaffirmed this position in the Federal Columbia River Transmission System Act of 1974 (Transmission System Act, 16 U.S.C. §838(d)), and in the Pacific Northwest Power Act (16 U.S.C §839f(d) and (i)). This principle was also reaffirmed by the Ninth Circuit Court of Appeals in Department of Water & Power of the City of Los Angeles v. Bonneville Power Administration and in California Energy Commission v. Bonneville Power Administration (see below, Section 1.3.5).

1.3.4 DESCRIPTION OF NEAR-TERM INTERTIE ACCESS POLICY

The Near-Term IAP was aimed at resolving immediate, discrete access issues resulting from immediate surplus and revenue conditions. The NTIAP established conditions for granting Pacific Northwest scheduling utilities 1/ assured delivery for firm power sales to California. In general, assured delivery is granted during each hour for sales up to an amount equal to each utility's average annual firm regional surplus (or 1.8 times that amount during certain months).

For Intertie capacity beyond that devoted to BPA's firm needs and assured delivery for other PNW entities' firm transactions, the policy establishes three different mechanisms for scheduling nonfirm power:

1/ Either those utilities that operate a generation control area or utilities within BPA's control area that schedule with BPA.

Condition 1 — The Exportable Agreement is in effect. 1/ This occurs generally under conditions of spill or imminent spill when more power at the applicable BPA rate is available than can be scheduled on the Intertie. Access is shared among BPA and Exportable Agreement parties only; there is no access for extraregional entities or other nonsignatories.

Condition 2 — Surplus PNW nonfirm energy at any price exceeds the scheduled capacity of the Intertie. Under this condition, access is shared among BPA and PNW scheduling utilities only, based on the ratio of each entity's declared surplus energy divided by the sum of all declarations; there is no access for extraregional entities.

Condition 3 — Surplus PNW nonfirm power at any price is insufficient to fill the Intertie. Under this condition, access is granted first to BPA and PNW scheduling utilities, with any remaining capacity available to extraregional entities.

In order to avoid encouraging the development of new resources, only energy from regional or extraregional resources of PNW scheduling utilities that were operational on September 7, 1984 (the implementation date of the Interim Near-Term IAP), is granted Intertie access.

Although extraregional utilities have access only under Condition 3, the Near-Term IAP includes a provision to allow these utilities additional access if those utilities agree to participate in planning and system coordination. No extraregional utility has reached such an agreement with BPA as of the date of this EIS.

1.3.5 LEGAL CHALLENGE TO NEAR TERM IAP: THE LADWP LAWSUIT

The City of Los Angeles Department of Water and Power (LADWP) challenged, in the Ninth Circuit Court of Appeals, the Administrator's action to develop and adopt an Interim Near-Term Intertie Access Policy, contending that BPA's control over hourly nonfirm access exceeded BPA's authority and was arbitrary and capricious. LADWP's contention was rejected in April 1985. The court focused on "whether the City of Los Angeles can purchase low-cost electricity from vendors in Canada and transmit that electricity at rates favorable to Los Angeles contrary to the pricing strategy of the Administrator."

1/ BPA's Near-Term Intertie Access Policy protects the rights of parties to the Exportable Agreement as a preexisting contract governing Intertie capacity allocations for sales of nonfirm power.

The court relied on the authorities cited above (in Section 1.3.3), noting that, in allocating space and facilitating arrangements, BPA did not have to compete with other PNW utilities for access to the Intertie, but, instead, should give itself preference. The Court also upheld BPA's authority to allocate remaining capacity first among other Pacific Northwest utilities and thereafter for extraregional utilities. The court stressed the statutory mandate that linked successful repayment of financial obligations with BPA's ability to raise adequate and justified revenues. Finally, the court found that Congress intended that the benefits of the Intertie be for PNW and California utilities, not for Canadian utilities. The court said that BPA may, but is not required to, agree to provide access to Canadian utilities. The court subsequently reaffirmed its holdings in California Energy Commission vs. Bonneville Power Administration 831 F.2d 1467 (9th Cir., 1987) and also upheld the Administrator's authority to restrict access by new non-Federal resources in order to protect fish and wildlife in the Columbia Basin.

1.4 LONG-TERM INTERTIE ACCESS POLICY

1.4.1 BACKGROUND

BPA's proposed Long-Term Intertie Access Policy is contained in Chapter 5 of this IDU EIS. The Long-Term Intertie Access Policy addresses Intertie access for long-term firm power transactions, hourly sales, and for new resources. Development of the Long-Term Intertie Access Policy has taken several years; a draft policy was issued as Chapter 5 of the IDU Draft EIS in October 1986. A revised draft of the policy was issued in December 1987.

1.4.2 ENVIRONMENTAL ANALYSIS OF LONG-TERM INTERTIE ACCESS POLICY

In October 1984, BPA announced its intent to prepare an EIS on the Long-Term IAP. 1/ In November 1984, BPA held two meetings to scope the issues to be resolved in the Long-Term IAP and to be examined in the EIS. About 60 people attended the scoping meetings held in Portland and San Francisco. Written comments were submitted by 24 parties. In addition, 11 parties submitted cross-comments. Comments received at the scoping meetings and during the comment period were reviewed and considered during the development of a Draft IDU EIS Implementation Plan.

BPA prepared a Draft Implementation Plan that identified the actions, alternatives, and impacts to be considered in preparing the EIS. The plan outlined how BPA intended to address the issues raised. BPA released the draft plan for public review and comment and scheduled a public consultation forum. Comment letters were received from 16 parties. The comments presented in these letters and in the public comment forum were reviewed and considered by BPA in developing a revised Implementation Plan, which BPA used to guide preparation of the IDU EIS.

1/ A list of this and all other major public involvement actions is found in Appendix J.

BPA's scoping process identified a range of environmental concerns. These included the effects on new resource development in the Pacific Northwest, California, and Canada; potential changes in river operations in the Pacific Northwest and Canada; potential changes in air quality and water quality in the Pacific Northwest and California as a result of changes in thermal generation; effects on fish and wildlife; and impact on regional economics.

Because of their roles in managing the Federal Columbia River Power System, the Corps of Engineers and the Bureau of Reclamation are both cooperating agencies in the preparation of the IDU EIS. Western has cooperated in the preparation of the IDU EIS by virtue of its special expertise concerning the Third AC/COTP. The Corps of Engineers assisted BPA in the analysis of potential impacts to fish by providing BPA with its "FISHPASS" computer model. The Bureau of Reclamation requested that potential effects on its storage reservoirs, including Hungry Horse and Grand Coulee, be addressed in the IDU EIS (including possible impacts on recreation, irrigation, and cultural resources).

1.5 CONNECTED ACTIONS: BC HYDRO'S PEACE SITE C PROPOSAL

In September 1985, Premier William Bennett of British Columbia proposed construction of the Site C dam on the Peace River in British Columbia. This dam would be built ahead of Canadian need for the purpose of exporting the power to the United States. BPA has encouraged discussions with BC Hydro, PNW utility representatives, and California utility and governmental interests to explore the Site C proposal, including PNW concerns with and interests in power from the project. Those discussions resulted in adoption of an agreement of principles to guide further study of the project and its implications. Among those principles are the need for increased Pacific Northwest/California Intertie capacity to accommodate the additional power proposed from Site C.

The Canadian proposal is in the early stages of discussion, and is not sufficiently developed to be included within this IDU EIS. If in the future the Site C proposal is found to be something in which BPA wishes to participate, the proposal will be subject to all relevant environmental and procedural requirements.

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ALTERNATIVES INCLUDING THE PROPOSED ACTION

Chapter 2

ALTERNATIVES, INCLUDING THE PROPOSED ACTIONS

2.1 INTRODUCTION

BPA's Administrator must make decisions about expanding Intertie capacity, the method for allocating hourly access to the Intertie and the types of long-term firm contracts under which power could be marketed over the Intertie. This chapter examines the various alternatives for those decisions and summarizes the environmental effects of the alternatives. The chapter discusses the proposed actions, the alternative of no action and several "decision packages" that illustrate different combinations of potential decisions that could be made by the Administrator. The decision packages involve: expansion of Intertie capacity; allocating access for spot market sales on the Intertie (formula allocation); and use of the Intertie for long-term firm export sales. For a more detailed discussion of the analyses supporting these comparisons, see Chapter 4.

The Administrator's proposal for expanding Intertie capacity is to (1) complete construction of the DC Terminal Expansion Project; and (2) to construct Intertie reinforcement facilities, including the Eugene-Medford 500 kV transmission line, in the Pacific Northwest and interconnect with the California/Oregon Transmission Project, thereby forming the Third AC Intertie. The Administrator also proposes to operate these facilities, as well as existing Intertie facilities, to make both firm and nonfirm transfers of power between the Pacific Northwest and California. The policies under which the Administrator proposes to provide both hourly and long-term firm access to the Intertie are presented in Chapter 5.

The chapter first discusses alternatives for expansion of Intertie capacity, then examines alternatives for formula allocation of Intertie access and long-term firm marketing. Access to the Intertie for utilities that are not located in the Pacific Northwest, designated as extraregional utilities, is also addressed. The rest of this chapter describes seven possible decision packages and their potential environmental effects.

2.2 INTERTIE CAPACITY

Four Intertie capacity levels are considered in this EIS:

- Maintaining the current capacity of the AC Intertie at about 3,200 MW and the DC Intertie at about 2,000 MW, for a total of 5,200 MW (Existing Capacity)

- Increasing the capacity of the DC Intertie facilities by approximately 1,100 MW (the DC Terminal Expansion Project)

- Increasing the capacity of the AC Intertie facilities by approximately 1,600 MW (the Third AC Intertie/California-Oregon Transmission Project)

- Completing both the DC Terminal Expansion Project and the Third AC/COTP for a total of 7,900 MW (Maximum Capacity)

Analysis of the existing 5,200 MW capacity level provides a "no action" baseline against which the effects of the proposed and alternative capacity expansions can be compared. The following sections describe and compare various capacity configurations.

2.2.1 EXISTING CAPACITY

The No Action alternative for BPA's Intertie capacity decision would be to leave the Intertie system at its existing capacity. Much of the time existing Intertie capacity is sufficient to accommodate most requirements for transmission of Pacific Northwest (PNW) nonfirm over the Intertie. However, recent requests for firm Intertie access would, if granted, restrict the amount of capacity available for transmission of nonfirm energy. Furthermore, during years of abundant water supply, flow on the Columbia and Snake Rivers is often so great that, for weeks or months, more electricity can be produced than transmitted over the Intertie. Moreover, the existing Intertie frequently does not have sufficient capacity to shape all deliveries into those hours of the day when the power would be of greatest value in the California market. This situation reduces the amount of revenue that the PNW can obtain from its sale of surplus and increases the cost of generation to California.

In each of the capacity options discussed in this section (Section 2.2), the indicated results are based on the assumption that the Proposed IAP will be implemented and that Intertie capacity will be used for long-term firm sales comparable to the Assured Delivery firm marketing option.

BPA's analysis predicts that, with existing Intertie capacity, sales of export power from the PNW and Canada to California would be approximately 3,100 average megawatts (aMW) in 1988. After the region's firm surplus begins to decline, Intertie sales would drop to between 2,800 and 2,900 aMW in the 1990s.

2.2.2 DC TERMINAL EXPANSION PROJECT (UNDER CONSTRUCTION)

The DC Terminal Expansion project increases the capacity of the DC Intertie line by approximately 1,100 MW. This is being accomplished by increasing the capacity of the converter facilities which transform AC power into DC for transmission over the DC Intertie at the sending end and back to AC at the receiving end. The DC Intertie was originally intended to be made up of two direct-current transmission lines between the Northwest and Southern California. Only one of the two lines, with its converter stations, was built. However, to increase system reliability, that line was sized to accommodate both the power supplied by its own converter stations and, during emergencies, the flow that would have been provided by the converter stations associated with the second line. In the event of a forced outage on one of the direct-current lines, the second line could have been used to carry the power being supplied to both of the lines.

Since the existing DC line can accommodate about twice the amount of power that can be delivered through its converter facilities, the functional capacity of the line can be substantially enhanced by increasing the capacity of the converter station without constructing any additional transmission lines. The construction costs of this upgrade are smaller, both environmentally and economically, than the costs of constructing a new transmission facility. The effects of facility construction are addressed in BPA's DC Terminal Expansion Environmental Assessment (February 1985) and Supplemental Assessment (July 1986). The Supplement focused on the effects of the Terminal Expansion on operation of the PNW power system. Similar, but updated, information is provided in this EIS.

Based on its supplemental analyses, BPA determined that a Finding of No Significant Impact (FONSI) is appropriate for the construction of the Terminal Expansion project. The contract for the construction phase was signed in late August 1986. Project construction is expected to require approximately 2 years, with completion and energization anticipated in early 1989. The Terminal Expansion is estimated to cost approximately $376 million (present value).

Subsequent to its release, BPA's FONSI was challenged in the Ninth Circuit Court of Appeals by the State of Idaho and others. BPA was ordered by the Court to prepare an EIS addressing the project in relation to other Intertie actions. BPA has agreed to complete the IDU EIS before making decisions on operation of the Terminal Expansion project.

The DC Terminal Expansion facilities in Oregon will be fully owned and operated by BPA. Thus, all north-to-south power deliveries over the DC Intertie will be subject to BPA's Intertie Access Policy. The line will directly access markets in Southern California, including the Los Angeles metropolitan area. BPA's analysis shows that, based on its value in providing transmission for additional economy energy sales, the DC Terminal Expansion project has an expected total net present value of approximately $1 billion (1987 dollars).

2.2.3 PROPOSED THIRD AC INTERTIE PROJECT/CALIFORNIA-OREGON TRANSMISSION PROJECT (COTP)

The California-Oregon Transmission Project (COTP) has been proposed by a consortium of publicly and privately owned California utilities. The Transmission Agency of Northern California (TANC) is the Project Manager. TANC is also the lead state agency, and the Western Area Power Administration (Western) is the lead Federal agency, for the preparation of a joint Environmental Impact Report (EIR)/Environmental Impact Statement (EIS) concerning the effects of project construction. Bonneville is a cooperating agency in the EIS/EIR. The EIR/EIS prepared by TANC and Western also contains a summary of the analyses of the project's environmental impacts resulting from changes in PNW power system operations (material also reported in more detail in this EIS).

The COTP would run north from the Tesla Substation in Central California to the vicinity of the California-Oregon border, where it would interconnect with the existing 500-kV system in Oregon. The COTP would involve construction of approximately 170 miles of new 500-kV transmission line in California, and the upgrading of about 170 miles of existing 230-kV transmission line owned by Western to 500 kV. The interconnection with the 500-kV system in Oregon would require about 8 miles of line in Oregon. It would also require the construction of a new substation (Southern Oregon Substation) at a location near Malin, Oregon. The Los Banos/Gates Transmission Project, a portion of which would support the COTP, includes construction of approximately 84 miles of new 500 kV transmission line, substation modifications, some realignment of the existing Los Banos/Midway No. 2500 kV transmission line, and reconductoring of the Gates/Arco/Midway 230 kV transmission line.

With minor modifications, the existing AC Intertie in the PNW is capable of delivering approximately 4,000 MW to California. However, the transmission system in California is only capable of receiving 3,200 MW. The COTP would upgrade the capacity of the southern system to 4,800 MW. So that this expanded capacity could be fully used, the northern portion of the system would be reinforced to increase its capability to 4,800 MW. This reinforcement (the Third AC project) would require modification of facilities at several substations and capacitor stations in the PNW. In addition, BPA has the option to acquire a 50-percent interest in Pacific Power and Light's planned Eugene-Medford 500 kV transmission line as part of the Pacific Northwest reinforcements. The potential effects of construction of the new Eugene-Medford line are addressed in an EIS issued by the Bureau of Land Management in May 1983. An environmental report (Pacific Northwest Reinforcement Project) concerning capacitor and substation additions and modifications necessary to increase the AC capability in the PNW was prepared by BPA and provided to Western and TANC for incorporation in the COTP EIS.

The Draft COTP EIS/EIR was released to the public in November 1986. Western and TANC issued the Final EIS/EIR in February 1988. No decision document on the project will be issued until Western has considered the IDU Final EIS. On February 16, 1988, the California Public Utilities Commission, which must approve the investor-owned utilities' (IOU) plans for the COTP, and inclusion of the costs of the project in their rates, rejected the IOU's applications for a certificate of public convenience and necessity to permit their participation in the construction and operation of the project. The IOU's were encouraged to file new applications in 60 days. Completion of project construction and energization is currently anticipated in 1991.

The Third AC/COTP Intertie project differs from the Terminal Expansion project in several ways. First, the 3rd AC would provide a larger capacity increase (1,600 MW vs. 1,100 MW). It would also provide access to a different market, because it would involve ownership by a considerable number of public as well as private utilities in California. Project participants are located primarily in Northern and Central California, rather than in Southern California. Many of the California participants in the Third AC/COTP have never before had direct access to PNW power. For these utilities (largely publicly owned), the Third AC/COTP could substantially reduce the costs of purchased power.

The project would require construction of substantial transmission line segments in California. Because the new line would be physically separated from existing Intertie lines by at least several miles over much of its route, the Third AC/COTP would contribute to the reliability of the whole Intertie system.

Only the facilities controlled by BPA would be subject to BPA's Intertie Access Policy. Those shares of the Third AC facilities that belong to utilities other than BPA would not be subject to the Intertie Access Policy.

A study of options for participation by Pacific Northwest non-Federal utilities in the northern portion of the Third AC Intertie was undertaken by the Bonneville Power Administration in response to a request made in June 1987 by several members of Congress who suggested that this issue required full consideration by the agency. The idea of non-Federal participation in the Third AC Intertie has been discussed by various parties in the Northwest over the past few years.

This study is being conducted in consultation with the public, including potential participants in the Third AC Intertie and a technical Peer Review Panel consisting of utility, government, and interest group representatives from the Northwest and California. Publication of the draft report in late January 1988, began a 30-day public review period. As of this writing, a final study was scheduled to be prepared and submitted to the Congress late in March 1988.

Five options are analyzed in the draft participation study.

Under Option 1, ownership of the AC Intertie would remain with Portland General Electric (PGE), Pacific Power and Light, (PP&L), and BPA, as reflected in current contracts. Other Pacific Northwest utilities wishing access to California markets would be allowed access to BPA's portion of the AC and DC Interties under conditions described in the LTIAP. Option 2 provides for continued ownership by PGE, PP&L, and BPA. However, new participants could lease up to 100 percent of BPA's share of the Third AC capacity above 4,000 MW (anticipated to be a little less than 800 MW). Option 3 is similar to Option 2, however, Option 3 does not incorporate the provisions for new resources and fish and wildlife protection of the draft LTIAP. Reassignment may be allowed subject to terms of the lease. In addition, the use of the lease would not be restricted to a particular type of transaction. Option 4 would allow for ownership by the non-Federal participants of BPA's share of the 800 MW of capacity above 4000 MW. The amount below 4000 MW would continue to be owned by PGE, PP&L, and BPA. Participants' rights could be sold or assigned, but only with the consent of PGE, PP&L, and BPA. Option 5 is the same as Option 4 except that the amount available for new non-Federal ownership would be 1,600 MW rather than 800 MW.

If a BPA proposal for participation evolves, further work to examine the environmental impacts of such a proposal and alternatives would be performed as required by the National Environmental Policy Act.

Total 1987 present value costs of the Third AC/COTP are estimated to be $883 million. BPA's analysis predicts that the Third AC/COTP (without the DC Terminal Expansion project), has a net (i.e., benefits minus cost) westwide present value of approximately $1.6 billion (1987 dollars). Its net present value as a "second-added" (i.e., added after the DC Terminal Expansion project) facility would be $950 million (1987 dollars). If the Third AC/COTP, as a second-added facility, were used only for increased economy energy sales, its net present value would be $661 million.

The BPA Administrator must decide whether or not to interconnect the COTP to the existing Intertie system and to upgrade the existing system in the PNW to accommodate the additional capacity. The Administrator will be considering both the IDU EIS and COTP EIS/EIR in arriving at such a decision. Participants in the COTP, including the Western Area Power Administration and the Transmission Agency of Northern California, will decide whether or not to construct the COTP.

2.2.4 MAXIMUM CAPACITY

Participation by BPA in both the Terminal Expansion and Third AC projects would increase the capacity of the Intertie from 5,200 MW to a total of approximately 7,900 MW for the combined AC/DC Intertie system. Adding both upgrades to the Intertie system would have an impact on total Intertie sales (approximately 600 to 700 aMW of additional sales in the years 1993-2003). However, the types of sales made, the operation of West Coast power systems, and the type and level of environmental effects associated with power generation in the study area could be affected. The Maximum Capacity condition would provide some additional flexibility in accommodating surplus generation in particularly good water years. It would also increase the PNW's ability to shape its sales into California's heavy load hours, when such power is most valuable in California and commands the best price for PNW sellers. It would permit expanded firm transactions that would benefit both California and the PNW. For purposes of the analyses in this EIS, Maximum capacity upgrade is assumed to become available in 1992.

BPA's analysis predicts that if both the DC Terminal Expansion and Third AC/COTP projects are completed, the Maximum capacity, assuming firm contracts, would lead to a net present benefit of nearly $2 billion (1987 dollars). If use of the additional capacity is limited to additional economy energy sales, the value of the Maximum upgrade decreases to about $1.7 billion.

2.2.5 FINDINGS ON ENVIRONMENTAL EFFECTS

Use of the expanded capacity of the Intertie is expected to have several small, although discernible, environmental effects.

Concentrations of air pollutants would increase very slightly near PNW coal-fired generating plants because increasing Intertie capacity would lead to progressively larger levels of coal generation in the PNW. In California, purchases of additional relatively inexpensive PNW energy would displace generation by more expensive oil and gas-fired plants. Consequently, air quality would improve slightly as Intertie capacity is increased in areas where the displaced plants are located. In the Inland Southwest, there also would be slight improvements in air quality as Intertie capacity increases. None of these effects are expected to be significant, however, since the magnitude of the projected changes in ambient air quality are very small.

In California, both the location and significance of effects differ among the alternatives. The Third AC predominantly benefits air quality in the San Francisco air basin and northern and central California, and offers relatively little benefit to the Los Angeles area. The DC Terminal Expansion project will have less effect on air quality in the San Francisco air basin and northern and central California. However, the DC Terminal Expansion will have a small, but positive, benefit in the Los Angeles air basin. Because of the higher population densities in the Los Angeles air basin, the beneficial air quality impacts of the DC Terminal Expansion are more significant than are those of the Third AC.

Upgrading the Intertie would have some small negative effects on anadromous fish stocks in the PNW. However, these adverse effects are insignificant relative to the increase in downstream passage survival provided by planned improvements in fish passage facilities.

BPA's studies found no changes in flow rates large enough to significantly delay downstream-migrating juvenile fish on either the Columbia or Snake Rivers with any of the upgrades. The ability to meet the Water Budget was not affected. Fish studies for the EIS 1/ suggest that decreases in average stock survivals due to the combined effect of changes in flow rates and the level of spill at dams resulting from the DC Terminal Expansion Project would be no more than 1.4 percent. The AC upgrade would decrease average stock survival by no more than 1.6 percent. The Maximum option would result in decreases in mean relative survival of no more than 2.9 percent. Given projected improvements in stock survival due to planned bypass improvements, effects of these magnitudes are not considered significant.

If planned facilities for improving fish passage assumed for the IDU analyses are foregone, even the small negative effects of increased capacity would be significant, since many stocks, currently in a potentially critical condition, would remain in that status or be placed in greater jeopardy.

1/ These studies cover all fish stocks for 3 study years (1993, 1998, and 2003).

None of the increased capacity alternatives would have a substantial effect on the spawning and emergence of salmonids in the Hanford reach of the Columbia River or on resident fish production in PNW streams or storage reservoirs.

As Intertie capacity increases, the amount of water consumed by closed-cycle power plants in the PNW would increase, and water consumption would decrease at California and Inland Southwest plants. Changes in water consumption by the Pacific Northwest, California, and Inland Southwest plants would generally not be significant. At California's Pittsburg and Contra Costa plants, significant problems with entrainment of aquatic life may be relieved slightly.

In British Columbia, upgrading the Intertie could slightly decrease available spawning and rearing habitat for resident fish species at Columbia River hydroelectric dams (particularly in the Duncan River and at Arrow Lakes Reservoir), but summer rearing habitat below Corra Linn Dam could increase. These effects in British Columbia would be more pronounced at larger Intertie capacity levels.

Intertie upgrades would have no appreciable effect on cultural resources, recreation, and irrigation. Expanded capacity, if used at least in part for firm transactions, could permit deferral of new resource construction (and associated capital investments and environment effects) in both regions.

2.3 INTERTIE ACCESS

BPA is establishing a policy to govern access to BPA-owned or BPA-controlled Intertie capacity. Chapter 5 contains BPA's proposed Long-Term Intertie Access Policy. Major issues addressed by the policy include the following:

- Access for utilities other than BPA to support long-term firm power sales and other long-term transactions, including seasonal exchanges.

- Establishment of a procedure for allocating hourly access to that portion of the Intertie not required to support long-term firm transactions.

- Access for new resources and hydroelectric resources. Access to hydroelectric resources is an issue because of potential impacts to fisheries and wildlife resources.

- Access for extraregional entities.

2.3.1 FORMULA ALLOCATION

BPA considered several options for allocating hourly access to the Intertie. Under the first of these options, termed the "Pre-IAP" formula allocation, BPA would return to the practices that governed the use of the Intertie before BPA adopted a Near Term Intertie Access Policy in

September 1984. In analyzing this option for this EIS, BPA assumed that the Exportable Agreement would not be renewed after it expires January 1, 1989.

As an alternative to the Pre-IAP option, BPA could adopt the formula allocation procedures of the proposed Long-Term Intertie Access Policy as presented in Chapter 5 of this EIS. These are referred to as the "Proposed Formula Allocation." Under this proposal, hourly access would be made available to Northwest utilities on a proportionate basis when demand for access by PNW utilities exceeds Intertie capacity. Extraregional utilities would receive access only when Intertie capacity exceeds access requirements of Northwest utilities.

A third formula allocation procedure that was analyzed was termed "Hydro-First." Hourly allocations under this option were made in the same manner as for the Proposed option except that all Pacific Northwest hydroelectric resources were dispatched before most other Northwest resources were dispatched.

The results of analyses of the Pre-IAP, Proposed, and Hydro-First formula allocation options are presented in detail in Chapter 4. In addition, analysis was performed on an option that would allocate access to the Intertie for spot market sales according to the relative environmental impact of Pacific Northwest coal-fired power plants in order to minimize adverse air quality effects of these resources on the Pacific Northwest. In modeling this option, Pacific Northwest coal plants were ranked according to their levels of air pollutant emissions. The least polluting coal plants were brought on line before "dirtier" plants.

Some commenters on the scope of this EIS suggest BPA should allocate access for hourly sales according to the relative environmental impact of Northwest resources of all types. Environmental dispatch would require that the relative environmental impact of generation by different resources be determined. This determination would require explicit tradeoffs among environmental values for which there are no widely agreed-upon rankings or regional preferences. For example, the environmental impact of increased air pollution from coal generation would have to be balanced against the impacts on salmon runs of increased generation on the hydroelectric system.

Even under the environmental dispatch option for coal plants, BPA would have to weigh impacts according to plants' emissions, locations, and surrounding populations, in order to determine the plants' relative damages. Weighing these factors in order to choose the environmentally preferable coal plant would require judgments about tradeoffs that are far from clear.

The environmental impacts of many Pacific Northwest resources vary greatly with the time of day, season of the year, weather, location, surrounding population, and other conditions. Hydroelectric generation, for example, may be more harmful during certain hours in months when fish migration is at high levels than at other times. Some coal plants' emissions have more potential for damage under certain meteorological conditions (for example, unstable air conditions) than at other times. Without hour-by-hour information about conditions at all Pacific Northwest power facilities, it would be impossible to accurately determine environmental impacts. Such an extensive data base on these variables does not exist.

Even if a determination could be made as to which PNW power resources are the least environmentally damaging, resource dispatch decisions to maximize environmental values in the PNW would often conflict with the goal of maximizing environmental benefits in California. If, for example, power from the environmentally preferable resources in the Northwest costs more than power from California resources, they would generate more power from oil/gas plants that pollute highly populated areas.

Environmental dispatch of all Northwest generating resources is simply not a reasonable alternative for allocating hourly access to the Intertie and would not meet the needs and purposes (described in Chapter 1) of BPA's proposed actions. Consequently, the environmental impacts of environmental dispatch are not quantitatively analyzed as an alternative in this EIS. BPA's analysis of environmental dispatch of Pacific Northwest coal resources is discussed in the response to comment number 03a1 in Volume 2, Part 1. An economic analysis of the effects of environmental dispatch is presented in Volume 1, Section 4.5.

Some commenters on the scope of this EIS recommended that BPA examine the possibility of allocating Intertie access for economy energy transactions using an "economic dispatch," "power pool," or "power broker" scheme. Such an alternative would allocate Intertie access on a real-time basis in order to minimize generating costs in the buying and selling regions. There are variations on this theme. For instance, Western U.S. utilities could agree to schedule least-cost generating resources to meet load throughout the interconnected region. Participating utilities would share hourly information on loads, resources, and operating costs. A central scheduler would dispatch resources in order to assure that the least-cost mix of resources was used to meet load throughout the interconnected region. The Intertie (as well as other transmission lines in the Western U.S.) would be used to insure that the lowest-cost power was used first.

Alternatively, selling utilities could declare the amount and price of surplus power they wish to sell, and purchasing utilities would declare either the price they are willing to pay or the decremental cost of their displaceable resources. A central scheduler would match the lowest-cost power offers in the PNW with the highest offers to buy or with decremental costs in the Southwest, until Intertie capacity was fully used. In such schemes, power would typically be priced at "share-the-savings" rates; that is, a rate midway between the costs of the buyer and seller.

Although economic dispatch and power brokering schemes have obvious economic advantages for the Western U.S. and Canada, there are many practical impediments that have, so far, limited the formation of such a pool. Such a scheme requires contractual agreement among the principal utilities within the region to share hourly information on loads, resources, and costs. Many utilities are reluctant to divulge such information about their operations. In addition, there must be a central scheduler with the responsibility and authority to match offers to buy and sell and to schedule the use of the Interties.

Nevertheless, approximately 10 utilities from the PNW, California, Inland Southwest, and Rocky Mountain States have recently formed a Western Systems Power Pool (WSPP). The Pool links some of the utilities in the Western U.S. for the purpose of sharing information about surplus power availability, and functions as a forum for negotiating transactions. The WSPP is primarily an agreement to share information, and not a full-scale power pooling agreement with any obligation to schedule transactions or implement share-the-savings rates. A power pool with these latter features has never been implemented on the scale proposed by commenters.

BPA's Long-Term IAP is not adequate by itself to accomplish the institutional and contractual changes required to implement an economic dispatch or power brokering system. In addition, economic dispatch or power brokering alternatives would not meet the needs and purposes (described in Chapter 1) of BPA's proposed actions. These are not reasonable alternatives to a BPA Intertie Access Policy, and therefore, an economic dispatch alternative is not examined further in this EIS.

Finally, the California Energy Commission has suggested that BPA reserve sufficient Intertie capacity to meet its own needs, and make remaining capacity available on a competitive pricing basis. This has been studied in the IDU Final EIS through analysis of the Pre-IAP formula allocation option (with Exportable Agreement terminating in 1989) at both the Existing and Maximum Capacity levels. The analyses at Maximum Capacity have been done for both the Federal Marketing and Assured Delivery firm marketing options. (See Tables 4.0-1 and 4.0-2 in Chapter 4.)

2.3.2 FINDINGS ON ENVIRONMENTAL EFFECTS OF FORMULA ALLOCATIONS

The Proposed Formula Allocation option has essentially the same effect on the environment as the Pre-IAP condition. However, differences were found between these options and the Hydro-First option for allocating nonfirm access.

Providing priority to sales from hydroelectric power facilities under the Hydro-First option maximizes the use of these facilities to meet export loads, while reducing the amount of power supplied by Pacific Northwest thermal generation. In years when abundant water supplies allow large amounts of hydro production (especially early in the year), power from Northwest coal facilities would generally not receive access. Even though capacity may be available later in the year, coal-fired generation could not recoup the earlier losses of Intertie sales. In addition, the total amount of export sales made over the Intertie would be reduced, because the coal plants cannot fill the Intertie completely during the latter portions of the year after hydro supplies have been exhausted.

Nevertheless, this loss of Intertie sales is relatively small, amounting to less than 2 percent of Intertie sales under the Pre-IAP Formula Allocation option. Under the Hydro-First option (compared with the Pre-IAP Formula Allocation option), hydro generation is approximately 2 percent greater, and coal generation approximately 5 percent less. The decline in export power sales from the PNW associated with the Hydro-First option results in slightly greater operation (less than 2 percent) of ISW resources. In California, the Hydro-First option results in slight increases in oil and gas generation (up to 3 percent) over levels occurring under the Pre-IAP option. Effects on other types of resources in California are negligible.

The Hydro-First option results in slightly improved projected air quality after 1988 in the analysis in the Pacific Northwest, as coal generation is reduced. This change is not significant however. In California and the Inland Southwest, there is very little difference in projected air quality among the formula allocation options. Thermal plant water consumption impacts would not change significantly under any of the formula allocation options.

Analyses of environmental impacts in British Columbia show that the Hydro-First option could affect resident fish production at the Columbia River projects in Canada. Changes in flows and reduced reservoir elevations at Libby, Mica, Arrow, Duncan, and Corra Linn Dams could reduce the production of Dolly Varden, Rocky Mountain whitefish, rainbow and lake trout, and kokanee.

Analysis of effects on recreation and cultural resources in the Columbia River Basin shows that the Hydro-First option would not affect those resources.

Compared to the Pre-IAP Formula Allocation option, both the Proposed Formula Allocation and the Hydro-First options would increase BPA revenues. However, impacts on retail rates would be negligible. Likewise, the effect of policy alternatives on retail rates in California would be negligible.

In British Columbia, the Hydro-First option would increase BC Hydro's secondary revenues slightly. The Proposed Formula Allocation option would have the opposite effect. In either case, however, the impact on BC retail electric rates would be negligible.

2.3.3 LONG-TERM FIRM MARKETING

There are two ways to sell power: on an as-available (nonfirm) basis, or on a firm basis. Traditionally, the Intertie has been used primarily for "as available" sales. Under the Near Term IAP, PNW utilities other than BPA have been able to offer California utilities firm contracts for only the duration of the Near Term IAP. Long-term assured delivery for the firm contracts of Pacific Northwest utilities other than BPA, as well as firm sales by BPA, would allow California utilities to plan on purchasing Northwest power and thereby defer capital investment in new resources. However, providing for long-term assured deliveries by other Northwest utilities would reduce BPA's flexibility in its use of the Intertie. A number of alternatives for analyzing the effect of assured access to the Intertie has been considered.

First, The Intertie could be used primarily 1/ for short-term Intertie transactions (nonfirm energy sales and short-term firm power sales). Such short-term sales are useful primarily to displace generation by existing, high variable cost resources in California, rather than to defer development of new resources.

Second, long-term firm sales over the Intertie of power from BPA, would allow the sale of substantial quantities of surplus resources on a long-term basis to California. To the extent that BPA's surplus is reliably assured for extended periods of time, California utilities would be able to use this power to defer capital investment for new resources. Because such purchases allow capital costs and operating costs to be displaced, BPA could expect to receive higher prices for transactions made with California under long-term contracts than for power sold under short-term spot market-type arrangements. BPA could also make Firm Displacement sales to Pacific Northwest utilities, thereby enabling the sale of surplus Northwest thermal resources to California.

Long-term firm contracts from utilities other than BPA would require that BPA provide such utilities assured delivery for their firm arrangements. Under the Near Term IAP, except for sales enabled by a Firm Displacement purchase from BPA or other joint ventures, assured delivery for long-term power sales is limited to the firm surplus of each Northwest utility, including BPA, from resources existing when the Interim Near-Term IAP was implemented, or 1.8 times that amount during certain months of the year.

The Near Term IAP does not allow assured delivery for seasonal exchanges and limits assured delivery for capacity transactions to each utility's average annual surplus (or 1.8 times that amount in certain months).

BPA is proposing to grant other utilities 800 MW of assured delivery for seasonal exchanges and firm sales based on each utility's average firm surplus.

1/ The "Existing Contracts" case also includes a limited number of firm contracts that either were in place at the time this analysis was prepared or that BPA anticipated would be concluded by Northwest IOU's and transmitted over non-Federal portions of the Intertie. A detailed description of the contracts modeled for each contract option is presented in Appendix B, Part 4.

2.3.4 FINDINGS ON ENVIRONMENTAL EFFECTS OF LONG-TERM FIRM MARKETING

Long-term, as opposed to short-term, firm transactions may affect the environment in two distinct ways. First, the level or shape of generation by existing and planned resources may change somewhat. More important, the level of resources required to serve load in both the PNW and California may be reduced when the Intertie is used for long-term firm power sales, including capacity and capacity/energy exchange transactions.

BPA's analysis found that long-term sales would have a very small effect on levels of generation by existing and planned resources. In the Northwest, coal generation and associated air pollution would be affected very slightly. Increases of between 5 and 10 percent occur in average overgeneration spill. Since this can be beneficial to migrating anadromous fish it is not surprising that firm contracts appeared generally to have a small beneficial effect on anadromous fish survival.

In California, oil and gas generation would increase slightly in the Federal Marketing case in order to provide the Northwest with exchange energy in the Northwest's dry years. For the Assured Delivery Case, California oil and gas generation would decrease slightly.

In the Inland Southwest, higher cost coal plants which provide economy energy to California respond to changes in firm sales conditions.

The choice of firm sales condition has little projected effect on Pacific Northwest air quality. For California and the Inland Southwest, Assured Delivery shows slightly better projected air quality than either Existing Contracts or Federal Marketing after 1988, a consequence of an assumed firm sale which results in a net flow of Pacific Northwest power to California. Similarly, Assured Delivery would be the most likely of the firm sales conditions to result in reductions of entrainment at California generating plants.

Long-term power sales, including capacity and capacity/energy exchange transactions, change resource requirements and, thus, change environmental impacts associated with new generating resources. In the Northwest, at Existing Intertie capacity, Federal Marketing firm sales conditions are projected to result in savings of 85 MW of new resources by 2003, whereas Assured Delivery is projected to result in the need for 131 MW of additional resources. Under Federal Marketing firm sales conditions, resource savings are possible because the Northwest can count on the availability of exchange energy from California in dry years, and thus can avoid constructing additional resources.

In California, long-term firm transactions should also lead to resource savings. The exact level of savings is difficult to estimate, and would depend on the nature of the contracts, California utilities resource plans, decisions of regulatory agencies regarding the development of Public Utilities Regulatory Policy Act (PURPA) Qualifying Facilities, and other factors difficult to predict. However, because California utilities would be able to plan on power from the PNW even in low PNW water years, they would be able to avoid acquiring California resources to provide the capacity and energy available from the PNW. This should lead to a small but significant cost savings for California utilities.

2.3.5 EXTRAREGIONAL ACCESS

Extraregional utilities, including BC Hydro, currently receive access to the Intertie only on an hourly allocation basis or through contracts executed before the September 1984 implementation of the Interim Near-Term IAP. Furthermore, hourly access is restricted to periods when the capacity of the Intertie exceeds the Pacific Northwest's supply of surplus energy available for sale to California (i.e., Condition 3 of the Near Term IAP). If such surplus capacity exists, extraregional entities are provided access only after the requirements of Northwest utilities have been met.

The Proposed IAP states that additional firm or nonfirm access for power from extraregional resources might be allowed, if the extraregional utility were to agree to participate more in the Pacific Northwest's coordinated planning and operation or were to agree to provide other appropriate consideration of value to the Northwest. No such agreement has yet been reached with any extraregional utility. Before any agreement could be implemented, BPA would have to complete all necessary environmental analysis and comply with any appropriate procedural requirements. Canadian Extraregional utilities will not be provided Assured Delivery until the Intertie capacity is rated at approximately 7,900 MW.

Provisions of the Proposed IAP are comparable to the provisions of the Near-Term IAP regarding access for extraregional utilities. These provisions were upheld by the Ninth Circuit Court in Los Angeles Department of Water and Power v. Bonneville Power Administration (1985). (See also California Energy Commission v. Bonneville Power Administration.) The court found that Congress had intended the Intertie to be used first for surplus from the Northwest. The Court ruled that BPA is not required to grant access for power from Canadian resources. (See Chapter 1.)

2.4 DESCRIPTION OF ALTERNATIVE DECISION PACKAGES AND THEIR POTENTIAL ENVIRONMENTAL EFFECTS

The preceding sections have described a variety of options available to BPA. These include decisions relating to Intertie expansion, formula allocation of hourly access to the Intertie and long-term firm marketing over the Intertie. Such decisions will not be made individually, but as an integrated package. The following sections describe several alternative "decision packages," providing an integrated evaluation of the potential environmental effects of actions BPA is considering. The packages presented below represent a broad range of reasonable decision alternatives. Readers may also consider other alternative decision packages and their environmental effects by drawing on the discussions of alternative capacity, formula allocation and firm contracts options in this chapter and in Chapter 4. For each of the alternate decision packages, the economic impact of the changed variables are shown. Each variable was evaluated independently (one at a time) and therefore the base case from which the impact is measured may change. Therefore, wherever a benefit number is shown, the corresponding base is also indicated. Table 2.1 shows the elements and major environmental effects of each decision package.

2.4.1 DECISION PACKAGE 1: NO ACTION
(Existing Capacity, Pre-IAP Formula Allocation, Existing Contracts)

If BPA took no action, Intertie capacity would remain at its existing level (approximately 5,200 MW) and, as discussed in Chapter 1, the Intertie would be used essentially on a non-allocated basis, except when the Exportable Agreement was in effect. Following expiration of the Exportable Agreement on January 1, 1989, access would be purely on a non-allocated basis. Assured delivery would be available only for pre-existing contracts or contracts over that portion of the Intertie not owned by BPA. There would be no new long-term firm power or capacity or seasonal exchange contracts by Northwest utilities. Access on a spot-market basis would be available to those utilities concluding agreements to sell power to California buyers. This circumstance, combined with limited Intertie capacity, would result in impairment of BPA's access to the Intertie. Such impairment would likely reduce the price received by BPA and other sellers, and would reduce the amount of power that BPA could sell. In addition, there would be no controlled management of access to the Intertie for new resources, extraregional resources, or hydro resources located in protected areas.

Under this alternative, consumption of gas and oil in California would be about 678,000 Barrels of oil and 420 billion cubic feet of gas. Coal consumption would be about 15 million tons in the Northwest and 24.4 million tons in the Inland Southwest. This option would result in approximately 600 average MW of overgeneration spill during the April through August period, a critical time for downstream migration of juvenile anadromous fish. The probability of being unable to coordinate fall and spring flows to permit successful spawning and emergence of anadromous fish in the Hanford Reach would be 0.31.

The No Action case would be expected to result in development of approximately 650 MW of conservation, 1,000 MW of nuclear and 125 MW of small hydroelectric resources--a total of about 1,800 MW of new resources by 2003.

Overall economic benefits of the use of the Intertie through the year 2030 under the conditions of the No Action package would be approximately $15.3 billion (1987 net present value).

2.4.2 DECISION PACKAGE NO. 2: PROPOSED ACTIONS
(Maximum Capacity, Proposed Formula Allocation, Assured Delivery)

The proposed actions would include participation in upgrading Intertie facilities to a Maximum capacity level of 7,900 MW (completing both the DC Terminal Expansion and Third AC/COTP projects) and adopting the formula allocation and firm sales provisions set forth in the Proposed IAP (see Chapter 5: Proposed Long-Term Intertie Access Policy). Decision Package No. 2 represents the Administrator's proposal. In general, power from new resources would be allowed on the Intertie only on an hourly basis or to sustain assured delivery contracts previously established on the basis of currently existing firm surpluses. However, in order to ensure protection of the Administrator's efforts to enhance the fish and wildlife resources of the Columbia River Basin, the allocation of any utility constructing a new hydroelectric resource in an area designated as "protected" will be decreased by the generating capability of that resource. The same provision would apply to additions to existing hydroelectric resources.

Largely as a result of the proposed capacity increase, average annual sales from the Northwest to California would be approximately 123 to 135 percent 1/ of the level anticipated under the No Action case. This figure is based on forecasted sales for study years 1993, 1998, and 2003. Year 1988 was excluded from this calculation because neither of the proposed capacity expansions would be operational at that time.

The major environmental effect of this decision package in California would be improvement of air quality slightly in both southern and north/central California. In the Northwest, changes in hydroelectric operations are projected to have small negative effects on some anadromous and resident fish stocks. However, BPA funded measures will be undertaken to mitigate effects on resident fish at Hungry Horse reservoir and fish and wildlife protection features of the Proposed IAP should discourage construction of new and expansion of existing non-Federal hydroelectric facilities that could interfere with the goals of the Columbia River Basin Fish and Wildlife Program and undermine BPA investments.

Cultural resources would be subject to slightly higher adverse effects from wave erosion, would be slightly less vulnerable to vandalism (due to decreased site accessibility resulting from higher summer reservoir elevations) than under the No Action case. No appreciable differences occur between the No Action and Proposed Action cases with regard to recreation or irrigation. The Proposed package would slightly raise overall development of new resources in the Northwest and decrease development in both California and the Inland Southwest compared with the No Action case.

1/ The level of effect is indicated as a range between the results for the Assured Delivery option and results for Assured Delivery Alternatives #1, #2, and #3. The latter alternatives incorporate higher levels of seasonal exchanges in place of the capacity/energy exchanges in the basic Assured Delivery option.

Emissions and coal consumption by existing Northwest PNW coal plants would increase slightly with this option. Overall, the need for new Northwest resources between 1988 and 2003 would be approximately 7 to 31 percent higher, depending on firm contract configurations, under the proposed than under the no action package. Although the exchange contracts included in the Assured Delivery cases reduce the need for development of Northwest resources, these reductions are more than offset, and to varying degrees, by the power sales contracts included. The resource needs would be filled primarily with nuclear power and conservation, along with a small amount of hydro development. 1/

Increasing the capacity of the Intertie gains about $2 billion in benefits relative to the Existing capacity, Proposed Formula Allocation, Assured Delivery scenario. Increasing the firm contracts from the Maximum capacity, Proposed Formula Allocation, Existing Contracts scenario gains about $800 million. The Proposed Formula Allocation option relative to the corresponding Pre-IAP option shows benefits reduced by about $50 million.

2.4.3 DECISION PACKAGE NO. 3

(Existing Capacity, Proposed Formula Allocation, Assured Delivery)

If, neither the Terminal Expansion nor the Third AC/COTP projects is completed, BPA could still choose to implement a Long-Term IAP. Decision Package No. 3 is intended to address this potential circumstance. In this alternative, BPA would not participate in upgrading the Intertie, but would implement the Long-Term IAP as contained in Chapter 5. Assumptions concerning formula allocation and long-term firm marketing are, therefore, the same as for Package No. 2.

Export sales from the Northwest to California would average from approximately 1 to 7 percent higher under Package No. 3 than under the No Action case during the study years. The environmental effects of Package No. 3 relative to the No Action case would differ primarily with regard to overgeneration spill and, to a lesser extent, consumption of nonrenewable resources. Overgeneration spill would be 4 to 10 percent greater under Package No. 3 than under the No Action case. Coal consumption in the Pacific Northwest and related land disturbance would be essentially the same as for the No Action case. Coal consumption in the Inland Southwest would be less than 1 percent lower than under the No Action case. Consumption of gas and oil in California would be essentially the same as the No Action case. Development of new Pacific Northwest resources would parallel that exhibited for the Proposal.

1/ The resource stack used for BPA's 1987 Resource Strategy contains 924 average MW of generating resources (consisting of small hydro, imports and combustion turbines) and a potential for 1,392 average MW of conservation. However, the resource stack used to model new resources for the IDU analyses did not include combustion turbines or long-term imports and assumed availability of only 815 MW of conservation by the end of the study period. If the Resource Strategy resource stack were used in the IDU analyses, less nuclear development would be indicated and it would be deferred to later in the study period.

The Assured Delivery (400 MW) feature of this case would provide approximately $650 million in net benefits above a scenario which would include Existing capacity, Proposed Formula Allocation, and Existing Contracts. The Proposed Formula Allocation relative to the corresponding Pre-IAP option shows benefits reduced by about $50 million.

2.4.4 DECISION PACKAGE NO. 4
(DC Upgrade, Proposed Formula Allocation, Assured Delivery)

In this alternative, BPA would participate in upgrading the Intertie with the DC Terminal Expansion project alone. It would also implement the Long Term IAP provisions outlined in Chapter 5.

This alternative would result in average Pacific Northwest sales levels for 1993, 1998 and 2003 approximately 12 to 21 percent above the level under the No Action case. Overgeneration spill would be only about 65 percent of that for the No Action case. Coal consumption in the Northwest and related land disturbance would be about 4 percent more than for the No Action case. Oil and gas consumption in California would be about 4 percent lower. Coal consumption in the Inland Southwest would decrease by less than 1 percent. Development of new resources in the Pacific Northwest would follow the same pattern as for BPA's proposal (about 7 percent more than for the No Action case). The addition of the DC Upgrade would result in a net benefit of about $1 billion and the use of the Intertie for Assured Delivery would add approximately $700 million in benefits relative to a (DC Upgrade, Proposed Formula Allocation) Existing Contracts scenario.

2.4.5 DECISION PACKAGE NO. 5
(DC Upgrade, Proposed Formula Allocation, Federal Marketing)

This decision package assumes completion of the DC Terminal Expansion Project, but not the Third AC Intertie. It also assumes adoption of the Proposed Long Term IAP, with one significant exception: BPA would not offer assured delivery to other Intertie users, although it would make firm sales of BPA's firm surplus energy and capacity over the Intertie.

Under Package No. 5 Pacific Northwest firm export sales would increase by approximately 9 percent, relative to the No Action case. Overgeneration would be approximately 40 percent less, Northwest coal consumption slightly higher, and gas and oil use in California and coal consumption in the Inland Southwest slightly lower than in the No Action case. The need for new resources is about 100 MW less by 2003 than under the No Action case, largely due to the capacity/energy exchange contracts included in the Federal Marketing Contracts option. The benefits of the DC Upgrade would be approximately $950 million relative to the Existing Intertie, Proposed Formula Allocation, Federal Marketing contracts scenario. The benefits of the long-term contracts would be approximately $600 million relative to the DC Upgrade, Proposed Formula Allocation, Existing Contracts scenario.

2.4.6 DECISION PACKAGE NO. 6

(Maximum Capacity, Hydro-First Formula Allocation, Assured Delivery)

In this alternative, BPA would participate in upgrading the Intertie to Maximum capacity, and, in addition, would implement the Long-Term IAP provisions outlined in Chapter 5, with one exception. The formula allocation option would be the Hydro-First alternative.

This Package would result in virtually the same level of Pacific Northwest export sales and overgeneration as Package No. 2. Other environmental effects of these two cases, including the need for new resources, would be roughly the same. The economic effects would be similar to BPA's proposal except that adoption of the Hydro-First formula allocation would reduce benefits by about $10 million less than is the case for the Proposed formula allocation.

2.4.7 DECISION PACKAGE NO. 7

(Maximum Capacity, Pre-IAP Formula Allocation, Assured Delivery)

Package No. 7 would result in maximum expansion of Intertie capacity and would provide assured delivery on a first-come, first-served basis. Impacts would be comparable to those under Package No. 2 in all respects except that the Pre-IAP formula allocation would increase economic benefits by about $50 million over those under the Proposed formula allocation.

2.5 EFFECTS OF ACCESS CONDITIONS ON NEW RESOURCES

BPA must decide about the kind of Intertie access to be granted to new (as opposed to existing) resources. Two types of access for new resources are under consideration.

Firm Sales From New Resources to Sustain Established Firm Contracts. BPA is proposing to limit assured delivery to energy from existing resources except insofar as new resources are needed to maintain service to established firm export contracts. This would preclude the development of resources in the Northwest for the purposes of increasing the amount of firm power exported by the region.

Unrestricted Access for Firm Power From New Resources. If BPA were to grant other utilities unrestricted assured access for power from new resources, resources that could be developed for firm service at a lower cost in the Northwest than in California could be used to displace the construction of new resources in California. This option should result in significant development of Northwest resources for service to California loads, because some new small hydro and other resource development may cost less in the Northwest than in California.

Table 2.1

SUMMARY OF MAJOR DECISION ELEMENTS AND ENVIRONMENTAL EFFECTS

Decision Packages

	PFEXB Package No. 1 No Action	PRMXA Package No. 2 Proposal	PREXA Package No. 3 No Expansion Proposal	PRDCA Package No. 4 DC/Assured Delivery	PRDCF Package No. 5 DC/Proposed Fed. Marketing	HFMXA Package No. 6 Hydro-First/Proposal	PFMXA Package No. 7 Pre-IAP/ Proposal
I. Decision Elements							
A. Intertie Capacity	5,200 MW	7,900 MW	5,200 MW	6,300 MW	6,300 MW	7,900 MW	7,900 MW
B. Formula Allocation Option	Pre-IAP	Proposed	Proposed	Proposed	Proposed	Hydro-First	Pre-IAP
C. Long Term Firm Contracts	Existing Contract Levels	Existing contracts; additional Federal marketing and assured delivery	Same as 2	Same as 2	Existing contracts with additional Federal marketing. No assured delivery.	Same as 2	Same as 2
D. Access for New Resources	No Restrictions	Access for new regional resources needed to support assured delivery (except hydro located in Protected Areas)	Same as 2	Same as 2	Same as 2	Same as 2	Same as 1
E. Extraregional Access	No Restrictions	Nonfirm access in Condition 3 only	Same as 2	Same as 2	Same as 2	Same as 2	Same as 1
F. Fish and Wildlife Protection	No Protection Features	Reduced access for new hydro within "Protected Areas." Applies to additions to existing resources.	Same as 2	Same as 2	Same as 2	Same as 2	Same as 1

Table 2.1 (Continued)

SUMMARY OF MAJOR DECISION ELEMENTS AND ENVIRONMENTAL EFFECTS

Decision Packages

	PFEXB Package No. 1 No Action	PRMXA Package No. 2 Proposal	PREXA Package No. 3 No Expansion Proposal	PRDCA Package No. 4 DC/Assured Delivery	PRDCF Package No. 5 DC/Proposed Fed. Marketing	HFMXA Package No. 6 Hydro-First/Proposal	PFMXA Package No. 7 Pre-IAP/Proposal
II. Environmental Effects							
A. Intertie Sales (aMW)							
1988	3,054	3,102-3,164	3,102-3,124	3,102-3,124	3,082	3,046	3,086
1993	2,798	3,249-3,388	2,789-2,916	3,049-3,135	3,016	3,227	3,239
1998	2,868	3,621-4,026	2,926-3,224	3,262-3,601	3,114	3,601	3,624
2003	2,895	3,657-4,093	2,956-3,245	3,298-3,644	3,183	3,648	3,669
B. River Operations							
1. System Refill Probability of July refill (%) Ave. of 20 years	85.7	85.6-85.8	85.4-85.9	85.4-85.9	85.6	85.8	85.8
2. Overgeneration (MW) Average Annual Over 20 years	296	103-110	308-329	187-202	178	99	101
C. Recreation Seasonal Recreation Index for Libby (average of 4 years studied.)	87.0	87.2	87.2-87.3	87.2-87.3	87.1	87.2	87.2
D. Irrigation Probability of being at or above 1,240 ft. at Grand Coulee at the end of May (%) (ave. of 4 yrs. studied)	82.0	82.0	82.0	82.0	82.0	82.0	82.0

Table 2.1 (Continued)

SUMMARY OF MAJOR DECISION ELEMENTS AND ENVIRONMENTAL EFFECTS

Decision Packages

	PFEXB Package No. 1 No Action	PRMXA Package No. 2 Proposal	PREXA Package No. 3 No Expansion Proposal	PRDCA Package No. 4 DC/Assured Delivery	PRDCF Package No. 5 DC/Proposed Fed. Marketing	HFMXA Package No. 6 Hydro-First/Proposal	PFMXA Package No. 7 Pre-IAP/ Proposal
E. Cultural Resources							
1. Wave Erosion Mean wave erosion index for Libby- % Change from Base (Ave. of 4 years studied)	Base Case	2.2 to 3.1	3.1 to 3.2	3.1 to 3.2	2.5	2.6	2.7
2. Site Accessibility Mean site accessibility index for Libby- % change from Base (Ave. of 4 years studied)	Base Case	-0.9 to -1.5	-1.6 to -1.7	-1.6	-0.4	-1.3	-1.4
F. PNW Fish							
1. Springtime flows (KCFS) (Priest Rapids Apr.-June ave. for 4 study years, no changes at Lower Granite)	143.8	144.5	144.6	144.3	143.9	144.1	144.2
2. Spill-average overgeneration spill (MW) for April through August period for 1993, 1998, 2003	606	134	644	374	335	126	130

Table 2.1 (Continued)

SUMMARY OF MAJOR DECISION ELEMENTS AND ENVIRONMENTAL EFFECTS

Decision Packages

	PFEXB Package No. 1 No Action	PRMXA Package No. 2 Proposal	PREXA Package No. 3 No Expansion Proposal	PRDCA Package No. 4 DC/Assured Delivery	PRDCF Package No. 5 DC/Proposed Fed. Marketing	HFMXA Package No. 6 Hydro-First/Proposal	PFMXA Package No. 7 Pre-IAP/ Proposal
3. Juvenile Anadromous Migrant survival	Base	No significant impact (requires currently planned fish bypass improvements at all projects except Ice Harbor and Bonneville	No significant impact (Requires currently planned fish improvements at Mid-Columbia dams.	No significant impact (Except not dependent on improved bypass at Lower Granite and Little Goose.)	No significant impact (Except not dependent on improved bypass at Lower Granite and Little Goose.)	No significant impact (Requires currently planned fish bypass improvements at all projects except Ice Harbor and Bonneville.)	No signifi- cant impact (Requires currently planned fish improvements at all projects except Ice Harbor and Bonneville.)
4. Hanford Reach spawning and emergence (percent) (Chance of failing to coordinate fall & spring flows based on all 20 contract years)	31.0 (Base)	29.6 (no significant change.)	30.0 (no significant change.)	29.6 (no significant change.)	30.4 (no significant change.)	29.2 (no significant change.)	29.3 (no significant change.)
5. Resident fish: Streams - Flows change below Libby and at Columbia Falls	Base	No significant change	Same as 2	Same as 2	Same as 2	Same as 2	Same as 2

Table 2.1 (Continued)

SUMMARY OF MAJOR DECISION ELEMENTS AND ENVIRONMENTAL EFFECTS

Decision Packages

	PFEXB Package No. 1 No Action	PRMXA Package No. 2 Proposal	PREXA Package No. 3 No Expansion Proposal	PRDCA Package No. 4 DC/Assured Delivery	PRDCF Package No. 5 DC/Proposed Fed. Marketing	HFMXA Package No. 6 Hydro-First/Proposal	PFMXA Package No. 7 Pre-IAP/ Proposal
6. Resident fish: Reservoirs Maximum monthly average decrease in elevation (feet) at Hungry Horse Sept., Oct., Nov. for 4 study years	Base	4.5 (Potentially significant impacts at Hungry Horse only)	4.2 (Potentially significant impacts at Hungry Horse only)	4.3 (Potentially significant impacts at Hungry Horse only)	5.0 (Potentially significant impacts at Hungry Horse only)	4.7 (Potentially significant impacts at Hungry Horse only)	4.7 (Potentially significant impacts at Hungry Horse only)
G. Fuel Use (Annual Average of 4 study years)							
1. PNW Land Disturbance (acres)	650	694	648	676	674	688	688
2. PNW Coal Consumption (1000 tons)	15,038	16,017	15,020	15,570	15,525	15,918	15,938
3. CA Oil consumption (1000 Bbls)	678	630	674	650	657	628	629
4. CA Gas consumption (1000 Gcf)	420	390	417	402	407	389	390
5. ISW Coal consumption (1000 tons)	24,359	23,998	24,291	24,179	24,262	24,006	24,009

Table 2.1 (Continued)

SUMMARY OF MAJOR DECISION ELEMENTS AND ENVIRONMENTAL EFFECTS

Decision Packages

	PFEXB Package No. 1 No Action	PRMXA Package No. 2 Proposal	PREXA Package No. 3 No Expansion Proposal	PRDCA Package No. 4 DC/Assured Delivery	PRDCF Package No. 5 DC/Proposed Fed. Marketing	HFMXA Package No. 6 Hydro-First/Proposal	PFMXA Package No. 7 Pre-IAP/ Proposal
H. PNW New Resource Development (Resource mix in 2003)							
1. Conservation (aMW)	646	664-719	Same as 2	Same as 2	656*	Sames as 2	Same as 2
2. Nuclear (aMW)	1,014	1,127-1,451	Same as 2	Same as 2	919*	Same as 2	Same as 2
3. Coal (aMW)	0	0	Same as 2	Same as 2	0*	Same as 2	Same as 2
4. Small Hydro (aMW)	124	124-167	Same as 2	Same as 2	124*	Same as 2	Same as 2
5. Total (aMW)	1,784	1,915-2,237	Same as 2	Same as 2	1,699*	Same as 2	Same as 2

* These data assume Maximum capacity rather than the 6,300 MW capacity level. Since analyses indicated virtually no difference in new resource effects between the Existing and Maximum capacity cases, no intermediate capacity analyses were conducted.

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Comparison of Environmental Effects of Access for New Resources

Alternatives for new resource access could substantially affect new resource development in the Northwest (see section 4.4). The contract configurations assumed for long-term firm export sales also significantly influence the amount and type of resources developed. Removing restrictions on access for new resources could result in approximately twice the development in the Northwest that could occur under the proposed new resource access conditions. Furthermore, the vast majority of this development would be coal generation. Firm sales configurations involving substantial participation by BPA could tend to emphasize development of nuclear rather than coal facilities due to the assumed availability of the WNP-1 and WNP-3 plants.

It is difficult to predict the likely effects of new resource access provisions on new resource development in California and the ISW. That effect would depend on many unknowns, including Intertie capacity, California utilities' future resource plans, power supplies, and regulatory agencies' policies on the acquisition and financing of new resources (including PURPA Qualifying Facilities). However, providing unrestricted firm access for new resources would allow California to make substantial new resource savings, or to substitute Northwest supplies for supplies from another region (most likely the Inland Southwest).

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AFFECTED ENVIRONMENT

Chapter 3

AFFECTED ENVIRONMENT

3.1 INTRODUCTION

The study area for the proposed action includes:

- the States of Washington, Oregon, Idaho; the portion of Montana west of the Continental Divide; and areas in Montana, Nevada, and Wyoming surrounding coal plants that serve the PNW (collectively referred to as the Pacific Northwest or PNW);
- the Canadian province of British Columbia;
- the State of California; and
- the States of Nevada, Arizona, Utah, and New Mexico (collectively referred to as the Inland Southwest or ISW).

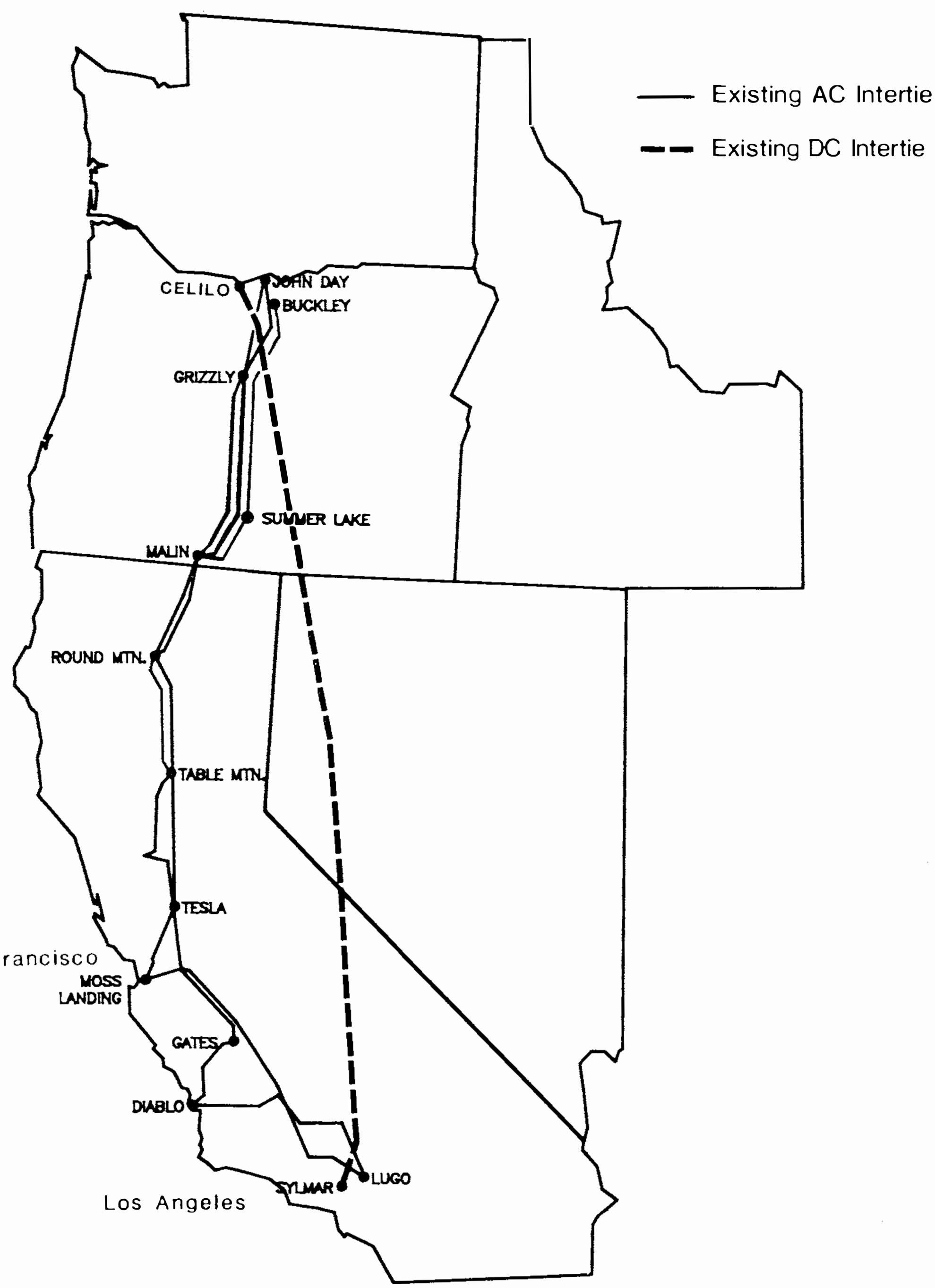
Power produced in any one of these regions is frequently transmitted for use in another region, depending on seasonal and peak-use needs. Transmission takes place over a network of high-voltage lines (Interties) that send power for long distances by direct or alternating current. A major element of this network is the Pacific Northwest/Pacific Southwest Intertie. (See Figure 3.1 for location of these lines.)

The National Environmental Policy Act (NEPA) requires a description of the environment where the proposed actions would take place. The discussion below covers a variety of resources and other variables throughout the study area which may be affected, to differing degrees, by the proposals. Individual discussions focus on regional differences where they are important; some discussions focus on the entire study area, as appropriate.

This chapter first examines social and economic considerations in the regions which make up the study area. Topics discussed include geography and land uses, population, industry, the Intertie system, available power resources, the demand for power, electricity rates, irrigation and recreational uses of the river systems and existing cultural resources. The chapter then describes the natural resources environment of the study area, focusing on air quality, water quality and fish, and wildlife and vegetation. Appendix A contains supplemental data on the topics covered in this chapter.

Figure 3.1

Existing Intertie System



3.2 SOCIAL AND ECONOMIC CONSIDERATIONS

3.2.1 GEOGRAPHY/LAND USES

The geography and land uses of the affected environment in British Columbia and the Pacific Northwest center on three river systems--the Columbia and the Peace Rivers in Canada and the Columbia/Snake River system in the Pacific Northwest. The Columbia River Basin includes more than 258,000 square miles of drainage, including most of Washington, Oregon, and Idaho; Montana west of the Rocky Mountains; small areas of Wyoming, Utah, and Nevada; and southeastern British Columbia.

3.2.1.1 Pacific Northwest River Systems

The Pacific Northwest may be divided geographically into several subregions: the Columbia River and Snake River Plateaus, and four regions of valley/plains (including the Puget Sound-Willamette Valley) separated by the Coast Range, the Cascades, and the Rocky Mountains. Half of the region is covered by forest (primarily Douglas fir), most densely west of the Cascade Range. Rangeland occupies substantial areas in the Snake River and Rocky Mountain regions. Agricultural lands are located primarily on the Columbia River Plateau, along the Snake River, and in the Willamette Valley. About two-thirds of the land in the region is publicly owned and managed, enabling the development of land management programs and extensive recreational opportunities. Land managers include the Federal Government (including the U.S. Forest Service, Bureau of Land Management, Department of Energy, and Department of Defense) and state and local governments. The rest of the land is privately owned.

The Columbia River passes from the province of British Columbia, Canada, into the State of Washington, dropping steadily for 748 miles to the Pacific Ocean. The Snake River, which begins in southeastern Idaho, flows west and north, forming part of the border between Oregon and Idaho and between Idaho and Washington. In southern Washington, the Snake River joins the Columbia, which flows west to the Pacific Ocean, forming the border between Oregon and Washington. The rivers flow through extensive wilderness, scenic, and recreation areas in the north and east, including the nation's deepest canyon (Hell's Canyon) along the Snake River. The rivers then pass through irrigated agricultural areas in the plateau lands east of the Cascade Mountains, and down through the Cascades and Coast Mountain Ranges to the Pacific Ocean.

The size of the two rivers and the drop in elevation once created spectacular falls and annual flooding as glaciers and snow melted in the mountains. However, over the last 50 years, both the Snake and Columbia Rivers have been dammed to control flooding, provide irrigation, improve navigation, and produce electricity. Libby Dam was built on the Kootenai River in Montana, in response to the Columbia River Treaty, a joint Canada-U.S. agreement to control flooding along international river systems (see Section 3.2.1.2). Its average flow is 11,970 cubic feet per second (cfs), with a recorded high of 121,000 cfs and a low of 895 cfs.

The lake formed behind the dam is 90 miles long, and extends into Canada. Other major Federal dams in the Columbia River System include Bonneville, The Dalles, John Day, and McNary (Columbia River on the Oregon-Washington border); Chief Joseph, and Grand Coulee (Columbia River in Washington); and Dworshak, Lower Granite, Little Goose, Lower Monumental, and Ice Harbor (Snake River). The location of Columbia Basin hydroelectric projects is provided in Figure 3.2. A complete list of the general specifications of Federal Columbia River Power System dams is found in Appendix A, Table A.1.

Federal hydro projects on the Snake and Columbia River systems are operated to provide for multiple uses, including power production, irrigation, navigation, flood control, recreation, fisheries, and wildlife. These sometimes competing interests are considered by the project owners and operators (the Corps of Engineers or the Bureau of Reclamation), who develop project operating constraints, stringent annual planning criteria, and shorter-term constraints as needed. Flood control constraints vary by project and are adjusted by the Corps of Engineers based on projected runoff volumes. Flood control and navigation requirements are not violated except in emergencies. Special short-term requirements may also be imposed as necessary by the project owner/operator.

3.2.1.2 British Columbia River Systems

Both the Columbia and Peace Rivers begin in the Canadian Rocky Mountains (see Figure 3.3). The area is heavily forested with Douglas fir in the mountains; valley bottoms in most areas are characterized by western hemlock stands. The Upland, Subalpine Zone in this portion of the study area includes Englemann spruce and fir. Portions of the Peace River drainage are located in the Sub-Boreal and Boreal Spruce zones.

In general, land uses include forestry, mining, and mineral processing, as well as some cattle farming and tourism in the Columbia River System. The forest industry dominates the western portion of the system; the eastern reaches include land uses such as agriculture, forestry, mining, oil and gas, and transportation. Water resource uses include recreation, transportation, and power production.

Columbia Lake, the source of the Columbia River, is situated 2,664 feet above sea level in southwestern British Columbia. The river flows north, then turns sharply to flow south to the international border, for a total of 459 miles and a drainage area of 39,550 square miles in Canada. Near the border, it is joined by the Kootenay River, which begins in the Canadian Rocky Mountains, proceeds south into Montana and Idaho, and then returns north into Canada before joining the Columbia (see Figure 3.4). The Peace River begins at the confluence of the Parsnip and Finlay Rivers, then flows east through the Rocky Mountains and onto the Alberta Plateau, eventually emptying into the Arctic Ocean (see Figure 3.5).

Streamflows on the Peace and Columbia Rivers are characterized by substantial snowmelt freshet, peaking in late June or early July.

FIGURE 3.2

Columbia River Basin Hydroelectric Projects

FIGURE 3.3

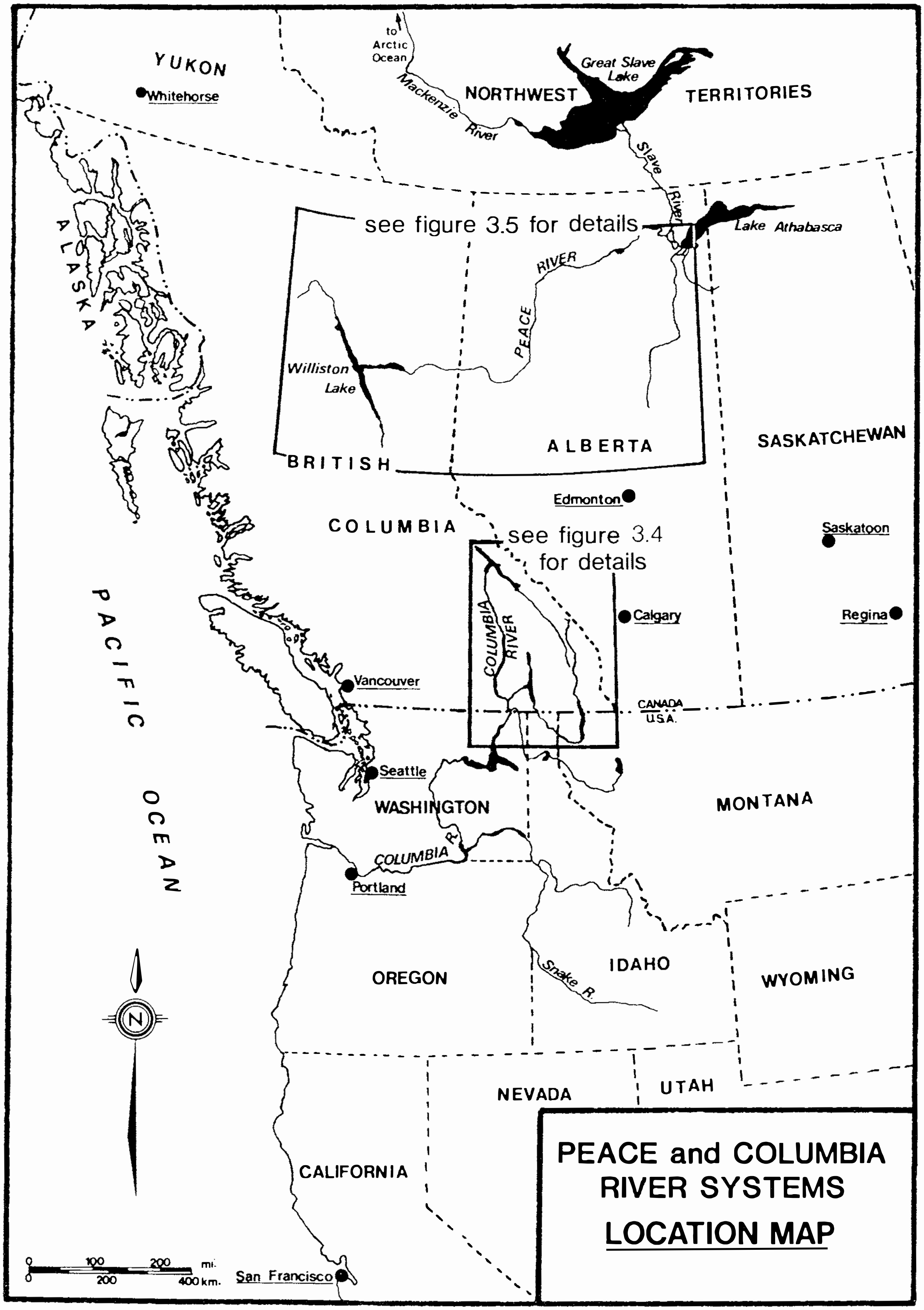
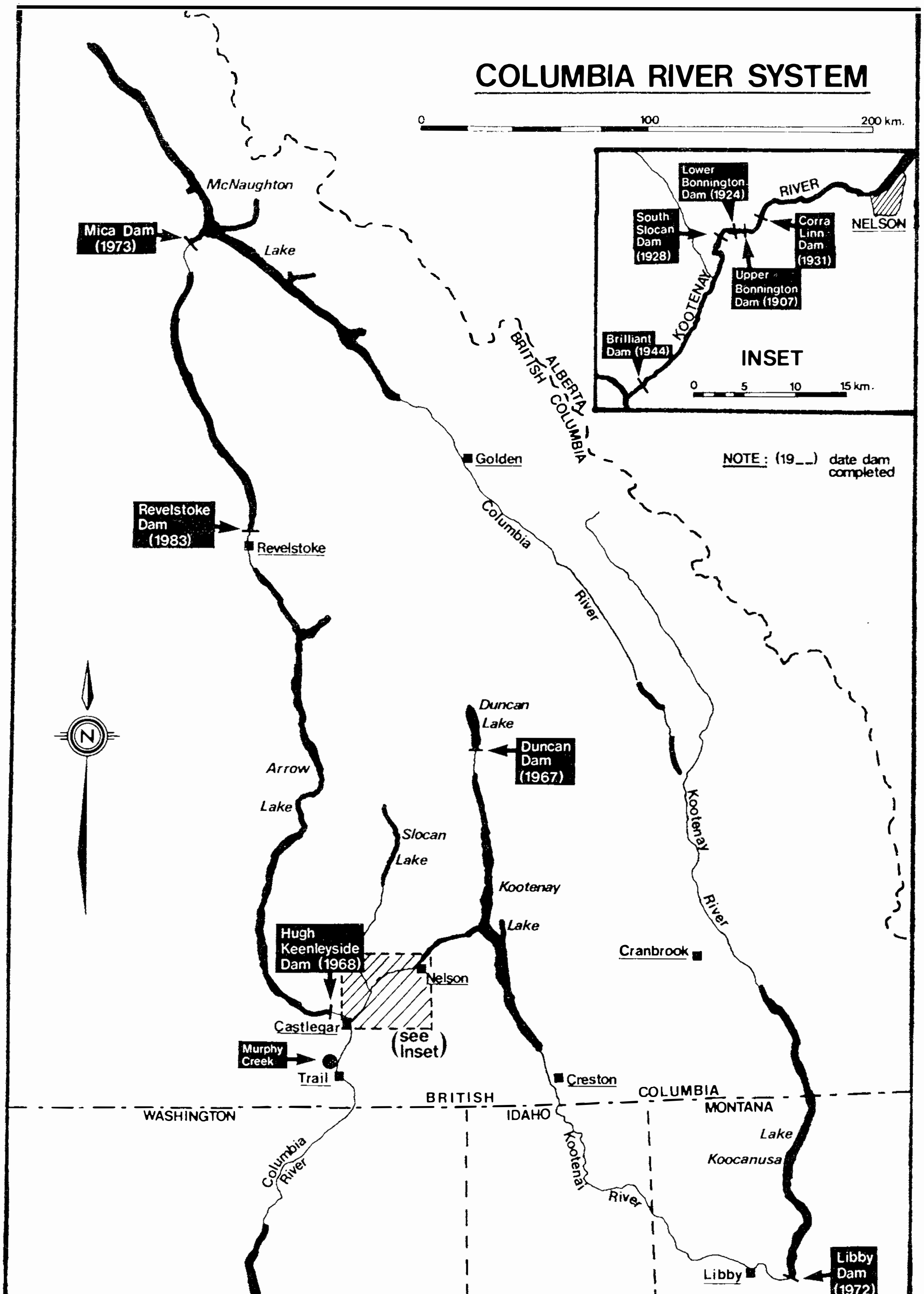

YUKON
Whitehorse
to Arctic Ocean
Mackenzie River
NORTHWEST
TERRITORIES
Great Slave Lake
Slave River
Lake Athabasca
ALASKA
see figure 3.5 for details
PEACE RIVER
Williston Lake
BRITISH
COLUMBIA
ALBERTA
SASKATCHEWAN
Edmonton
Saskatoon
see figure 3.4 for details
COLUMBIA RIVER
Calgary
Regina
PACIFIC
OCEAN
Vancouver
CANADA
U.S.A.
Seattle
WASHINGTON
MONTANA
COLUMBIA R.
Portland
IDAHO
Snake R.
OREGON
WYOMING
NEVADA
UTAH
CALIFORNIA
N
0 100 200 mi.
0 200 400 km.
San Francisco
PEACE and COLUMBIA RIVER SYSTEMS
LOCATION MAP

FIGURE 3.4


COLUMBIA RIVER SYSTEM
0
100
200 km.
McNaughton
Lake
Mica Dam (1973)
Lower Bonnington Dam (1924)
RIVER
South Slocan Dam (1928)
Corra Linn Dam (1931)
NELSON
Upper Bonnington Dam (1907)
KOOTENAY
Brilliant Dam (1944)
INSET
0
5
10
15 km.
BRITISH COLUMBIA
ALBERTA
Golden
NOTE: (19__) date dam completed
Revelstoke Dam (1983)
Revelstoke
Columbia
River
Duncan
Lake
Duncan Dam (1967)
Arrow
Lake
Slocan
Lake
Kootenay
Lake
Kootenay
River
Cranbrook
Hugh Keenleyside Dam (1968)
Nelson
Castlegar
(see inset)
Murphy Creek
Trail
Creston
BRITISH
COLUMBIA
WASHINGTON
IDAHO
MONTANA
Lake
Koocanusa
Columbia
River
Kootenai
River
Libby
Libby Dam (1972)

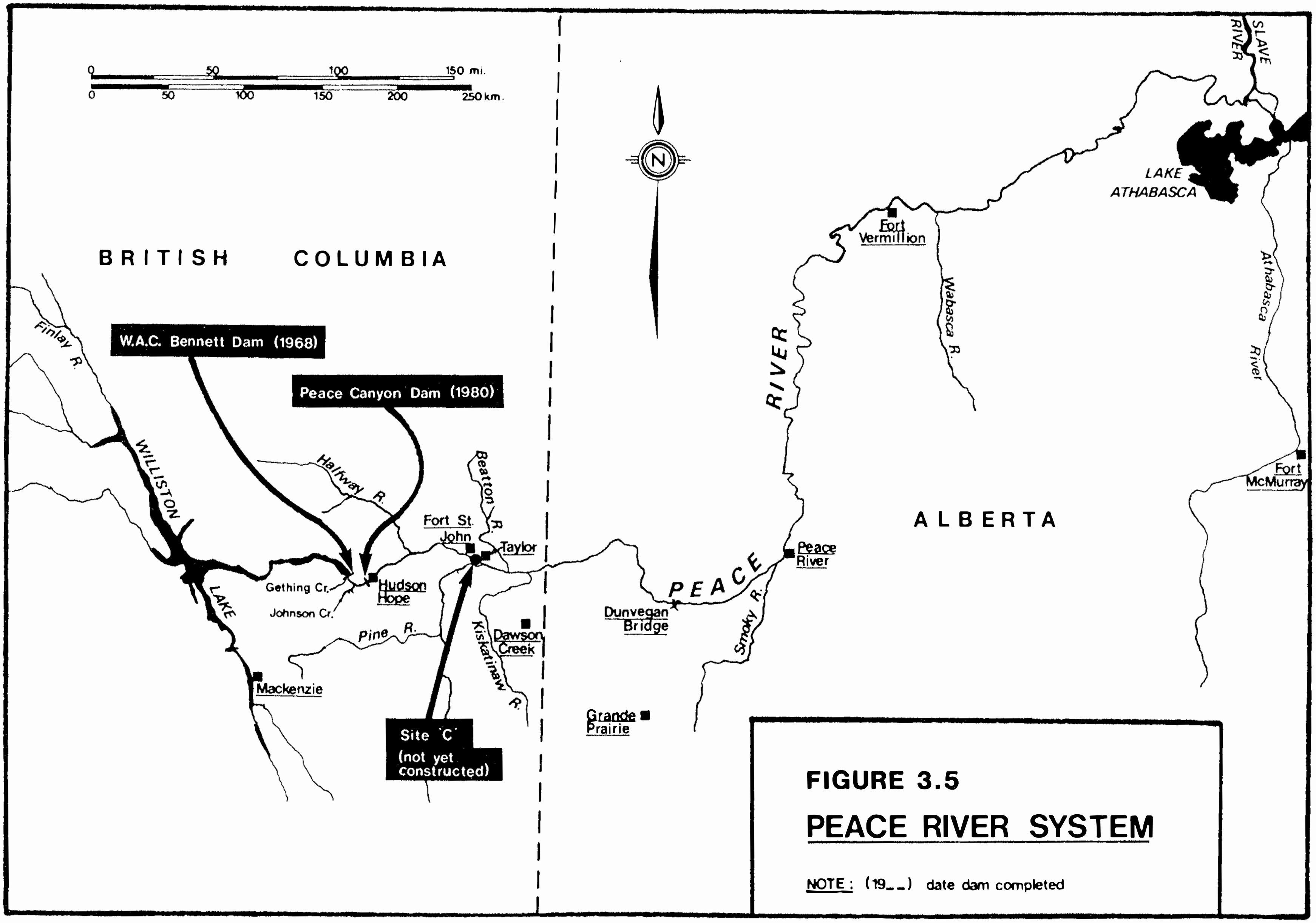


FIGURE 3.5

PEACE RIVER SYSTEM

NOTE: (19__) date dam completed

Regulation of both river systems by dams has reduced seasonal streamflow variations and, on the Columbia, reduced the occurrence and severity of flooding along the river. The average annual flow (1932-1982) of the Columbia River at the International Boundary is approximately 100,000 cfs. Maximum daily flow (during an extensive flood in 1948) was 456,840 cfs. Minimum recorded daily flow (December 1945) was 20,400 cfs.

Control of Columbia River water flow in Canada is now aided by dams built since the signing of the Columbia River Treaty between the United States and Canada in 1964. The purposes of this treaty are to prevent flooding and to aid production of power. Under the treaty, the Canadians built Mica Dam (McNaughton Lake) and Keenleyside Dam (Arrow Lakes) on the Columbia River and Duncan Dam (Duncan Lake) on the Duncan River, a tributary of the Kootenay River. (Elevation ranges at Canadian reservoirs are presented in Appendix A, Table A.2.) Electrical generators are installed at Mica Dam, and the feasibility of installing generators at Keenleyside Dam has been studied. Duncan Dam has no generators.

Also built on the Columbia is Revelstoke Dam, a large generation facility located on the mainstem Columbia downstream of Mica Dam. It is operated as a run-of-river plant. 1/ Corra Linn Dam, completed in 1931 on the Kootenay River, formed Kootenay Lake.

On the Peace River system, the W.A.C. Bennett Dam created Williston Lake, the largest single reservoir in British Columbia, with a storage capacity of 57 million acre feet. Since regulation, maximum streamflows have been approximately 70,000 cfs (compared to unregulated peak flow of 311,000 cfs) and minimum annual flows between 10,000 and 21,000 cfs. A second dam downstream (Peace Canyon Dam, Site One) takes advantage of a drop in elevation below Bennett Dam to produce power, but, as a run-of-river dam, does not regulate water for flood control. (Envirocon Ltd., 1988.) A third dam on the Peace River, to be located at what is called "Site C," has been proposed by the British Columbia government. This dam could be built ahead of British Columbia's need in order to export power to the U.S. The Site C dam would be another run-of-river dam, located downstream of the Peace Canyon dam. (See Section 1.5, CONNECTED ACTIONS: BC HYDRO'S PEACE SITE C PROPOSAL.)

1/ Run-of-river plants do not <u>store</u> water, but produce power from the natural run (or flow) of water downstream.

Ice formation on the Peace River has been altered by the presence of the dams. The river gradually ices over from downstream up during the fall and winter. Bennett Dam eliminated formation of the ice sheet upstream of the town of Taylor, but also increased occurrence of ice jams and flooding of basements in the town of Peace River. Tests have sought to determine whether increases in flow (to facilitate power production) created corresponding changes in ice formation and movement. The tests found that flow increases eroded the ice sheet at its leading edge, and flooded the ice sheet at the town of Peace River. Such flooding could increase the thickness of the ice and potential problems with breakup (ice pileup on shore, increased flooding). However, no problems were observed in the spring of the test year (British Columbia Hydro and Power Authority, October 1982).

3.2.1.3 Physical Geography/Land Uses of California and the Inland Southwest

California and the Inland Southwest include some of the driest portions of the United States. Physiographically, the region is composed of the Coast Ranges, the Central Valley, and the Sierra Nevada Range (all in California), the Basin and Range provinces, the Colorado Plateau, and portions of the Rocky Mountains. Topographically, the region encompasses the lowest and some of the highest elevations in the continental U.S.

The Colorado River Basin is the major drainage for the region, rising on the Continental Divide and ending at the Pacific Ocean. It contains major multi-purpose dams such as Hoover Dam, which provides electric power, water supplies, and recreation areas.

California can be divided into three major land resource regions (California Facts, 1985). Beginning on the coast, the Northwest Forest, Forage and Specialty Crop Region is characterized by steep mountains, broad gently sloping valleys and terraces, arid soils, dense forests of coastal redwoods, and forest and grass vegetation. Elevations range from sea level to less than 4,000 feet. Further inland, the Siskiyou Trinity Area ranges from about 300 to 8,900 feet. It contains rounded but steeply sloping mountains, narrow valleys with gently sloping floodplains and alluvial fans bordered by sloping foothills. It supports forest, open forest, and prairie vegetation.

The second major region, the California Subtropical Fruit, Truck, and Specialty Crop Region, has low mountains, broad valleys, a long warm growing season, and low precipitation. This region is heavily irrigated, and contains the major population concentrations. It ranges in elevation from sea level to over 12,000 feet in some cases, although most of the region is substantially lower. Vegetation consists mostly of grasses and brush, with a strip of forest in the Southern California Mountains.

The third California land resource region is the Western Range and Irrigated Region. It is a semidesert-to-desert region of plateaus, basins, plains, and many isolated mountain ranges. Elevations vary from more than 1,300 feet below sea level to over 14,000 feet at Mt. Whitney and Mt. Shasta. The majority of the mountain ranges trend north-south. Slopes vary from almost level to precipitous, and vegetation varies from shrubs, grasses, pine and fir forest in the north to sparse desert vegetation in the south. The mountain ranges exert major influences on the climate of the region, with extremes evident in several areas.

The Inland Southwest is in the Basin and Range, Colorado Plateau, and Rocky Mountain provinces. The land is fairly arid, except for the Rocky Mountains, which are moderately wet. The area tends to be water-limited, with most precipitation occurring in the mountains. Vegetation usually ranges from desert to mountain forests.

3.2.2 POPULATION

In the Pacific Northwest, population is centered around Seattle/Tacoma (WA), Portland/Vancouver (OR/WA), Eugene/Springfield (OR), Spokane (WA), and Boise/Nampa/Caldwell (ID). Washington population has grown from about 4.13 million in 1980 to about 4.38 million in 1985, a 6 percent net increase (Washington Population Center, June 1986). The population of Oregon (1980-85) has increased from about 2.63 million to an estimated 2.67 million, a net increase of 1.5 percent. Population in British Columbia is centered around Vancouver, Victoria, and a few smaller centers. The population of the province has grown from approximately 2.5 million in 1976 to about 2.87 million in 1984 (Canada Almanac and Directory, 1986). California population is centered around Los Angeles, San Diego, San Francisco, San Jose, and Sacramento. Los Angeles represents the greatest concentration of population in the study area, with 11,000,000 people living within the air basin. California population for 1985 was 26,365,000, an increase of 2.2 percent over 1984 (Annual Estimates of Population of California Counties: July 1980-85). Major population centers in the Inland Southwest (such as Salt Lake City, Phoenix, Tucson, Albuquerque, Santa Fe, Las Vegas, and Reno) tend to be much smaller than those in California.

Population is potentially relevant for this project because it affects load growth (see Section 3.2.6). It is also relevant for evaluating the significance of changes in air quality (see Section 3.3.1).

3.2.3 INDUSTRY/ECONOMIC BASE

3.2.3.1 Pacific Northwest

The economy of the Pacific Northwest is heavily resource-based. The extensive forests provide material for lumber, wood products, and pulp and paper. These industries and others, such as chemical and metal (principally aluminum) production, rely heavily on historically cheap hydroelectric power produced by the abundant water resources of the region. The size and extent of the river systems allow large withdrawals for irrigation, a critical economic factor for agriculture, particularly in central and eastern Washington. The Columbia River Basin supports a large number of anadromous fish stocks, a resource important to the Pacific Northwest for the substantial economic value of the sport and commercial fisheries and for the high cultural and religious value to Columbia River Basin Tribes and others. The river systems are also economically important in providing multiple recreational opportunities (including boating, swimming, fishing, and windsurfing) and scenic tourist attractions, including the nationally valued Columbia River Gorge, and Hell's Canyon, the nation's deepest river gorge. Finally, the river systems provide economic support for trade, in the form of transportation of goods into the interior of the PNW.

Although the wood products industry is not electricity-intensive, its size in the region (as the major manufacturing industry) makes it the fourth largest industrial consumer of electricity. Primary metals production, pulp-and-paper production, and chemical production are first, second, and third in industrial electric use.

As might be expected, unemployment rates in the PNW have always been higher than the national average because of the cyclical nature of the region's economy. For instance, almost 28 percent of manufacturing employment was in lumber, wood products and pulp and paper in 1980. The reduction in demand for those products has seriously affected employment, although there has recently been a recovery in the wood products industry. Similarly, a ninefold increase in the cost of electricity to the aluminum industry between 1979 and 1983 (in response to increased costs of BPA power and implementation of provisions of the Pacific Northwest Power Act) contributed to plant shutdowns and layoffs of workers (BPA, 1983 Power Rate EIS), although most plants are operating now. Unemployment rates in Oregon and Washington were 9.7 and 8.3 percent, respectively, for March 1986 (Washington Labor Market Report, April 1986; Oregon State Employment Division, personal communication, June 1986).

3.2.3.2 British Columbia

The economy of British Columbia as a whole, and especially the areas through which the Columbia and Peace Rivers flow, is heavily resource-based. Forestry, mining, and mineral processing industries are important sources of income and employment. In many cases, these industries rely on the river system either for power or transport. The river systems are also closely tied to another important economic base: tourism and recreation (Envirocon, 1986).

In British Columbia, high unemployment (currently at 12.7 percent, seasonally adjusted) has resulted from the regional economic dependence on natural resources (Labor Force Document 71-001).

3.2.4 INTERTIE SYSTEM

The Pacific Northwest/Pacific Southwest Intertie exists to transport power between the PNW and California. (The physical facilities are described in Chapter 1.)

At present, the three transmission lines together have a capacity of about 5,200 MW. Since 1968, they have carried more than 1,256 average megawatts (aMW) of surplus energy from the Pacific Northwest to

California, ranging from less than 170 aMW in 1973 to almost 3,800 aMW in 1982. The current level of surplus energy exported to California is approximately equal to the output of three large (1,000 MW) coal or nuclear plants.

Energy transmitted to the Southwest over the Intertie system is generated at hydro or thermal plants in or associated with the PNW or Canada. Power generated in the PNW is transmitted to The Dalles area (northern terminus of the Pacific Northwest/Southwest Intertie) over the region's high voltage transmission system. Power from Canada is carried over BC Hydro's grid to one of two links between BC and the PNW: a pair of 500-kV lines near Blaine, Washington, and another pair of 230-kV lines north of Spokane. Total transfer capability between the BC Hydro and BPA systems is currently 2,000 MW. From the Canadian border, power from BC is transmitted over the PNW transmission grid to The Dalles area, where it feeds into the Intertie. Of the total energy exported to California over the Intertie, 11 and 9 percent was from Canadian sources in FY 1984 and FY 1985, respectively.

3.2.5 POWER RESOURCES/RESOURCE MIX

3.2.5.1 Pacific Northwest

Hydropower produces about two-thirds of the total electricity used by the Pacific Northwest. There are 58 major hydroelectric dams, including 31 Federally owned dams, with a combined capacity of 22,000 MW. The amount of streamflow varies from month to month and from year to year according to weather and other natural conditions. In years of heavy runoff, water is readily available to produce electricity needed in the PNW; when streamflow is down, water stored behind dams is released to provide additional flow. In an average year, 16,400 aMW of hydro power is produced; in a very low water year, both streamflow and storage may be reduced, and only about 12,300 aMW may be produced. In the United States, major storage reservoirs exist behind Libby, Grand Coulee, Albeni Falls, Hungry Horse, and Dworshak dams. Three Canadian dams (Mica, Keenleyside and Duncan) also provide substantial water storage.

Few sites remain in the Pacific Northwest that could effectively accommodate additional major hydroelectric development. As more power is required, other ways to produce power are being added to the power base. In addition to the hydroelectric system, electricity for the region is also produced at 14 coal units and two commercial nuclear plants. (See Appendix A, Table A.3 for a listing of major Northwest thermal power plants.) Thermal power plants have higher variable costs than hydro plants. However, the ability to operate thermal plants does not depend upon natural conditions such as weather and water supply.

The PNW energy resource mix also includes energy conservation. The 1980 Pacific Northwest Power Act directs BPA to give the highest priority to cost-effective energy conservation in acquiring resources to meet load. BPA's conservation programs are designed to improve the efficient use of electricity across all broad end-use categories (residential, commercial, industrial, and irrigated agricultural sectors). By improving end-use efficiency, energy conservation offers a means of regulating load growth and thus offsets the need for new generating resources.

BPA energy conservation programs promote energy efficiency in two ways: first, through installation of energy conservation measures (such as insulation, double glazing, more energy-efficient motors and appliances) in existing facilities (e.g., sewage treatment plants) and structures; and, second, through promoting the incorporation of energy-efficient features in new buildings and facilities. By encouraging energy efficiencies in new buildings, loads will increase at a slower rate despite regional population and economic growth.

Achievable regional conservation potential varies according to cost. Estimates included in BPA's 1985 Conservation Supply Document show a range of achievable regional energy conservation savings for the period 1988-2005 from 627 MW at 13 mills/kWh (levelized 1985 dollars) to 1,758 MW at 52 mills/kWh. These savings accrue from energy conservation efforts in the following end-use categories: existing residential, new manufactured housing, appliances, water heating, new and existing commercial, irrigated agricultural, industrial, and direct-service industries. 1/

3.2.5.2 British Columbia

The energy resource mix in British Columbia is almost entirely hydro, and is primarily produced by B.C. Hydro and Power Authority. The only major thermal plant, a gas/oil plant on Burrard Inlet in Vancouver, is not normally used, but is maintained in case of an abnormally dry water year or unexpected load growth (Envirocon, 1986).

3.2.5.3 California

Numerous entities produce power in California: investor-owned and municipal utilities, the California Department of Water Resources (which generates and purchases power) and the Western Area Power Administration (which markets power produced at Federal dams). The generating systems operated by these entities can together produce about 45,000 MW. About half of this generating capacity consists of oil- and gas-fired power plants. Next is hydroelectric capacity (about 20 percent), followed by nuclear, coal, geothermal, and cogeneration. About 25 percent of California's energy requirement has been provided in recent years by firm contracts with utilities in the ISW and the PNW (Independent Power Corporation (IPC), 1986).

The resource mix in California has been influenced, in part, by two factors: the Power Plant and Industrial Fuel Use Act of 1978 and the historically high cost of gas and oil. The Act sought to spur utilities

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1/ BPA, 1985 Conservation Supply Document, pg. 1.3, March 1986. These estimates do not include estimated energy savings accruing from implementation of Model Conservation Standards, which are estimated at 400 MW by 2005, but counted as a load reduction rather than optional resources for meeting load demands.

and industries to convert power production to a coal-burning base, and to reduce the consumption of petroleum products. It contained strict prohibitions against constructing new oil- and gas-fired plants in large industrial boilers, except for peaking use (less than 1,500 hours per year). As a result of the relatively high costs of oil and natural gas in the past, ISW coal-fired generation and surplus power from the PNW have been used to displace production from California's oil and natural gas plants. The recent plummeting of gas and oil prices in the U.S. has led to an increase in gas and oil generation in California and to a decrease in imports from out-of-state.

California utilities obtain crude oil from both domestic (Alaska and California) and foreign sources (Indonesia, South America, and the Middle East). About 80 percent of the oil refined in California is extracted from domestic wells, mostly from California oil fields. Approximately 90 percent of the natural gas consumed in California is imported from the Southwest and Canada. Small amounts are also received from Rocky Mountain and Mexican natural gas fields. Remaining needs are met by domestic natural gas resources (California Energy Commission, 1984). The domestic supply, initially available at low cost, was a major factor behind the original decision to build oil- and gas-fired power plants (Biosystems, 1986).

Data for California power plants on plant capacities, fuel sources by plant, and transportation methods used to deliver fuels from refineries or extraction fields are presented in Appendix A (see Table A.4). Appendix A also includes values for fuel receipts and consumption (Table A.5), generation by resource type (Table A.6) and fossil fuel consumption (Table A.7) for the years 1980 through 1984. These data clearly indicate a substantial decline in the use of fuel oil during this period. From 1979 to 1984, natural gas consumption by electric utilities represented from 23 to 35 percent of the total state demand for natural gas. Although utilities reduced natural gas use in 1983, consumption rose again in 1984, reaching its highest level since 1981. Utility consumption of residual fuel oil imports, which in the late 1970s accounted for 22 percent of total residual fuel receipts by major markets, declined to approximately 5 percent by 1988 (Biosystems, 1986).

California Energy Commission forecasts indicate that adequate supplies of natural gas will be readily available throughout the late 1980s and early 1990s. After 1995, forecasters predict that gas supplies for electric power generation could drop 25 percent below forecasted needs, with shortages appearing first in southern California. At that time, electric utilities could switch either to residual or distillate fuels (fuels distilled from crude oil), which California refiners could supply, or could seek other electric power sources (Biosystems, 1986).

Nuclear, cogeneration, and renewable resources are resource types of major importance to California's future energy supply. While it is unlikely that significant numbers of new nuclear plant projects will be initiated in coming years, several projects now under construction are scheduled to be on-line in the late 1980s and early 1990s. The development of renewable and cogeneration energy has been spurred by the Public Utilities Regulatory Policy Act (PURPA) and the California Public

Utilities Commission's active support of development of renewable and cogeneration resources, known as Qualifying Facilities (or QFs) under PURPA. California utilities project that they may acquire over 5,500 MW of capacity from QFs between 1986 and 2005 (Common Forecasting Methodology VI submissions to the California Energy Commission). These projections are made on the basis of current avoided-cost methodology, which is now being examined by the California Public Utilities Commission. Changes in standard offers and or avoided costs paid to QF developers may reduce the amount of QF capacity that is developed.

3.2.5.4 Inland Southwest

The Inland Southwest study area resource mix includes hydro, coal-, gas-, oil-fired, and nuclear generation. Coal provides the major source (approximately 58 percent of generating capacity), with oil/gas (26 percent) and hydro (about 17 percent) following. The Palo Verde (Arizona) Nuclear Plants #1 and #2 (1,270 MW each), which began commercial operation in 1986 and 1987, respectively, account for 9.3 percent of the region's installed capacity. As much as 62 percent of the area's total capacity has been available to supply export power to California and other areas (Biosystems, 1986). Additional data on Inland Southwest generating capacity by resource type is presented in Appendix A, Table A.8.

3.2.6 DEMAND FOR POWER

3.2.6.1 Pacific Northwest

Electric loads within the Pacific Northwest vary according to geographic location and season. The Puget Sound-Willamette Valley region, where two-thirds of the population lives, uses the largest amount of electricity, most of it in the winter for heating. East of the Cascades, the difference between winter and summer loads is less pronounced in some areas due to summertime irrigation and air conditioning loads. In some cases, summertime loads of utilities serving heavy irrigation loads actually exceed those utilities' winter loads.

Industrial users account for half of electric consumption, and residential users for one-third. Because the region's hydro-based power has historically been much less expensive than power in other regions, residential customers in the region use twice as much electricity at half the cost per kilowatthour as the national average.

Half of Pacific Northwest loads are served by BPA, which markets power made available from U.S. Army Corps of Engineers and Bureau of Reclamation dams and two nuclear facilities: Washington Public Power Supply System Plant No. 2, and a share of the Trojan plant. The public utilities and investor-owned utilities (IOUs) sell their own generated power or power from BPA to regional end-use consumers (those who use and do not re-sell the power). BPA's authority (see Chapter 1) stipulates that it serve all requested needs within the region first, and that it supply power to public utilities and cooperatives before IOUs. Only if more power is available than is needed by the region can it be sold and transmitted outside the region.

Demand forecasts in the late 1970s anticipated an energy shortage. New generating resources were planned and built into the early 1980s. However, demand for electricity did not increase as expected. Consequently, new plants, added in anticipation of the resource deficit, have resulted in a surplus of firm energy that will be available for a number of years. The region currently has about 1,000 aMW of surplus firm energy, in addition to the surplus nonfirm energy that BPA and other utilities can have available annually in varying amounts, depending on water conditions. BPA therefore has sought to increase markets outside the region. The region's energy surplus is estimated to last for 20 years if regional electricity demand is low, and for less than 3 years if regional demand is higher (see Figure 3.6 for a graph of average firm surplus).

3.2.6.2 British Columbia

In British Columbia, the 1985 load was approximately 3,600 aMW, and the projected load for 1987 is approximately 3,800 aMW. Load growth is projected to be 2.3 percent per year between the 1984-1985 and 1995-1996 operating years. Under BC Hydro's low load forecast, anticipated firm hydro surplus would decrease from 900 MW in operating year 1985-1986 to 0 MW in operating year 1995-1996.

3.2.6.3 California

Statewide peak electricity demand in California in 1982 was 35,434 MW. Ninety-five percent of this demand was from the three largest investor-owned utilities and the two largest municipally owned utilities. The California Energy Commission (CEC) forecasts that between 1985 and 2004, statewide peak electricity demand will grow by about 1.9 percent annually and electricity sales will grow by about 1.7 percent annually. Individual growth rates projected for the large utilities range from 1.4 to 2.7 percent annually for peak demand and from 1.6 to 2.5 percent annually for electricity sales (IPC, 1985).

In order to meet these and other needs (such as maintenance, energy losses, and so on), California's major utilities plan to develop their own resources, to purchase from facilities owned by private developers, to purchase capacity and energy from other utilities, 1/ and to develop conservation and load management programs. Statewide resource additions amounting to approximately 10,000 MW of capacity and 4,600 aMW of energy are likely to be available within the CEC's current 12-year planning period (IPC, 1985).

3.2.6.4 Inland Southwest

In the Inland Southwest study area, current load is approximately 8,373 MW, divided among Arizona (4,069 MW), New Mexico (1,315 MW), southern Nevada (736 MW), and Utah (2,136 MW). Total generating capacity is far greater than load, allowing over 60 percent of the power produced to be exported to serve other markets such as California.

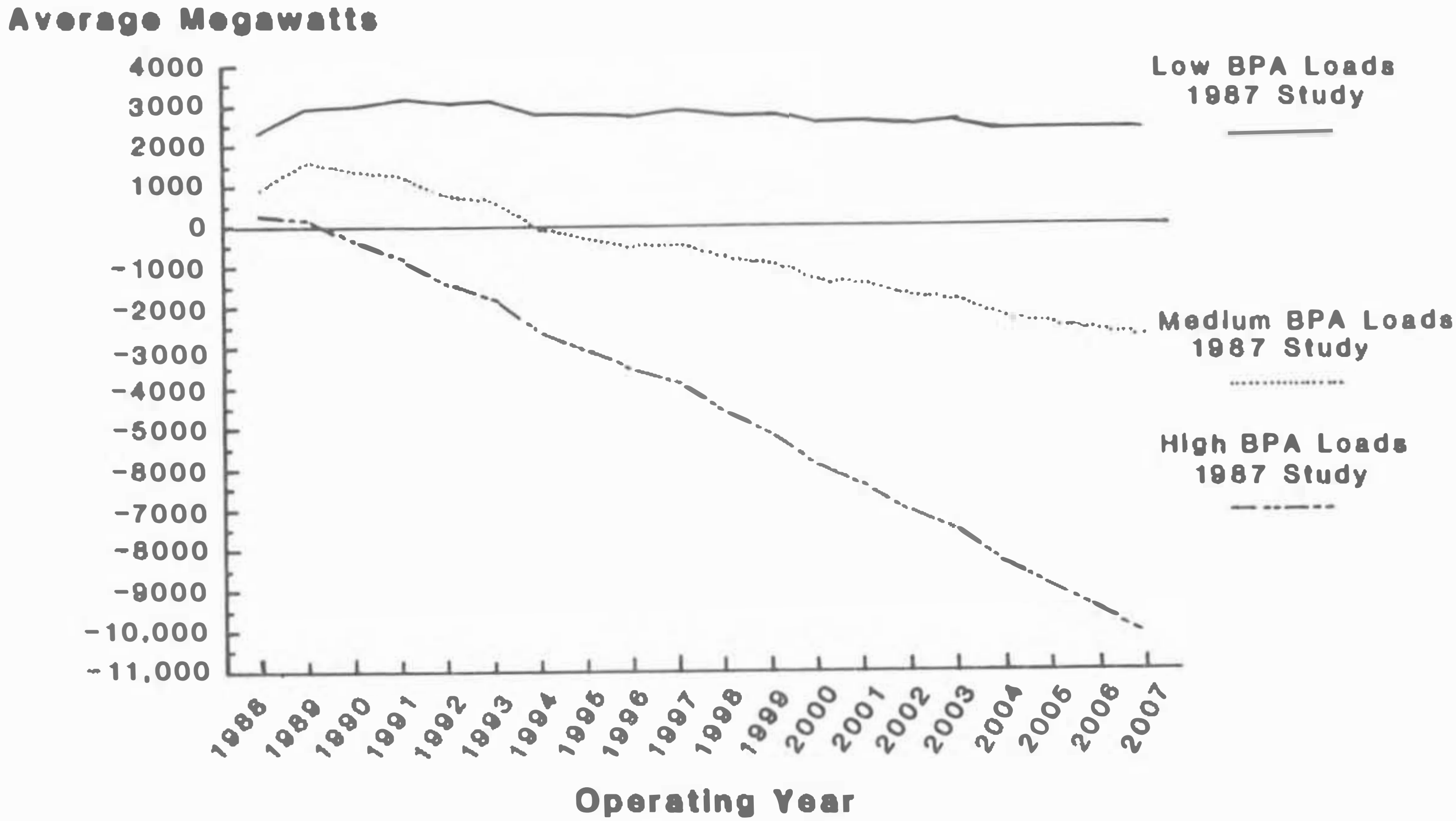
1/ Contracts with Northwest and Inland Southwest utilities have supplied as much as 25 percent of California's energy needs in recent years.

Figure 3.6

REGIONAL FIRM ENERGY SURPLUS/DEFICIT

20-Year Projection

Assuming No New Resource Acquisitions



BPA - RPSE
11-18-87

Source is 1987 Pacific Northwest Loads & Resources

3.2.7 ELECTRICITY RATES

3.2.7.1 Pacific Northwest Rates

BPA sells wholesale electricity to publicly owned utilities for resale to their residential, commercial, and irrigation consumers; to investor-owned utilities in an amount equal to their residential and small farm consumer load; to direct-service industries (primarily aluminum smelters); and to other regional and extraregional customers as requested. Electricity produced at the Pacific Northwest dams has been inexpensive; thus, BPA's rates for wholesale power have traditionally been low relative to wholesale rates in the rest of the United States. Before 1979, residential electric rates rose more slowly in the Northwest than in the rest of the nation. In recent years, rates in the Northwest have risen more rapidly due to the inclusion of the costs of the Washington Public Power Supply System's Nuclear Plants 1, 2, and 3 and, to a lesser extent, programs mandated by the Pacific Northwest Power Act. The increases in BPA's average rate to its publicly owned utility customers are:

1938-1965	--
1965	7 percent
1974	28 percent
1979	94 percent
1981	56 percent
1982	60 percent
1983	22 percent
1987	6 percent

About half of the retail power bill paid by a typical PNW residential ratepayer covers the utility's costs of wholesale power from BPA. In 1985, average residential retail rates in the Pacific Northwest were estimated to be about 57 percent of the national average.

3.2.7.2 California Rates and Costs

Electricity prices vary substantially among utilities and among customers of utilities. According to the California Public Utilities Commission, current average rates for California's largest investor owned utilities are as follows:

	cents/kWh
Pacific Gas and Electric	7.9
Southern California Edison	8.3
San Diego Gas and Electric	10.8

Differences among customers served by the same utility also occur due to differences in the amount of electricity purchased, timing of use, and interruptibility of power.

3.2.7.2.1 Projected Costs and Rates

California utilities have projected electricity demands, costs, and prices to the year 2004 as a part of their Common Forecasting Methodology VI (CFM VI) filings with the California Energy Commission. The Los Angeles Department of Water and Power, Pacific Gas and Electric, and Southern California Edison project that their sales of electricity will grow at a rate of 2.1 percent per year from 1987 to 2002. Average retail rates are projected to grow from 10.3¢/kWh in 1987 to 25.3¢/kWh in 2002. Average rates corrected for inflation are projected to increase only slightly from 1987 to 1997 and then to grow 2 percent per year more rapidly than the general rate of inflation. Total costs (i.e., the cost of operating plants), including the cost of purchased power, are projected by these utilities to increase about one-third faster, in real terms (i.e., after adjustment for the general rate of inflation), than the growth in sales. Other costs (including distribution, service, and capital costs) are projected to grow more slowly. By the end of the period, these fixed costs are expected to be a much smaller share of total cost per kilowatthour than they are at present.

The shares that various energy sources contribute to running costs change due to their changing shares of total generation and to different rates of escalation in costs. According to the CFM-VI filings, the cost of generation in oil- and gas-fired plants is projected to increase by 90 percent, in real terms, by the year 2002. (The current change in the oil and gas market may reduce this projected increase.) The price paid for power from cogeneration and other Qualifying Facilities is tied to the cost that can be avoided by replacing the "marginal" unit; therefore, the price of QF power rises with the price of oil and gas. On the other hand, the running costs of generation from nuclear, coal, and geothermal plants and the price of nonfirm power from the Northwest are projected to increase only slightly more rapidly than the rate of general inflation. The running cost of oil and gas plants is projected at about 130 percent above the cost of Northwest nonfirm power in 2002, whereas it is expected to be only about 40 percent above the import price in 1987.

3.2.8 OTHER USES OF RIVER SYSTEMS: RECREATION AND IRRIGATION

3.2.8.1 Recreation

3.2.8.1.1 Pacific Northwest

In the Pacific Northwest, the Wild and Scenic Rivers Act of 1968 has included as part of its system the following rivers: Rogue and John Day Rivers (Oregon); Middle Fork of the Salmon and Clearwater Rivers (Idaho); and portions of the Middle Snake River on the Oregon-Idaho border. Numerous other rivers are being studied for inclusion in the system. The Act establishes guidelines for protection of recreation, wildlife, scenic vistas, and other values of designated rivers. None of the rivers named above is expected to be affected by the proposed Intertie actions.

In the Pacific Northwest, Federal hydro projects provide numerous opportunities for recreation at the storage reservoirs and the areas downstream. Boating, swimming, water skiing, and fishing are typical water-related recreational activities; other recreation opportunities include camping, picnicking, sightseeing, hiking, and recreational hunting. Many recreation activities are influenced by changes in reservoir elevation and downstream flows. Changes in Intertie capacity or policy may affect reservoir operation and, consequently, recreation.

Predictable changes in elevations or flows are more likely to occur at storage hydro projects, which operate reservoirs on an annual drawdown/refill cycle to maintain a balance among multiple uses (such as flood control, power generation, recreation, and fisheries), than at run-of-river projects. Reservoirs are also operated on a daily and hourly basis to meet power requirements, minimum flows, project restrictions, and other short-term requirements. Day-to-day and hourly project operations are less predictable than longer-term operations.

Run-of-river projects, by contrast, cannot store much water, and are operated on a daily and hourly basis to meet power needs and other project restrictions. Effects of Intertie capacity or policy changes at these projects also are not predictable, since their operation depends on short-term decisions.

The five Federal storage reservoirs discussed below are operated seasonally. They offer many recreational opportunities, including boating, fishing, camping, picnicking, swimming, hiking, sightseeing, hunting, and wildlife viewing. Reservoir drawdown is based on necessary flood control space and on power generation requirements. Maximum and minimum reservoir elevations are shown in Appendix A, Table A.9.

Libby Reservoir

Activities: Boating, fishing, camping, picnicking, swimming, hiking, sightseeing. The reservoir behind Libby Dam (Lake Koocanusa) is a major recreation area in northwestern Montana. The reservoir also extends 42 miles into Canada when it is full. Most of the area surrounding the project in the U.S. is administered by the Forest Service as part of the Kootenai National Forest. The Corps of Engineers and the Forest Service have constructed boat ramps, campgrounds, picnic areas, swimming beaches, and hiking trails along the lake. Except for a visitor facility and day-use area at the dam (operated by the Corps of Engineers), all recreation facilities in the U.S. are administered by the Forest Service. Fishing is a prime recreation interest in the area. About 85 percent of the recreation use occurs during the three-month period from July through September.

Most of the land surrounding the reservoir in British Columbia is administered by the Ministry of Lands, Parks, and Housing. The remaining land is privately owned or leased. Recreation facilities in the Canadian portion of the reservoir include boat launching ramps, swimming and picnicking areas, campsites, hiking trails, and a charter boat service.

Hungry Horse Reservoir

Activities: Camping, fishing, boating, sightseeing, wildlife viewing. The 34-mile-long Hungry Horse Reservoir is located on the South Fork of the Flathead River, entirely within the Flathead National Forest in Montana. The Forest Service administers recreation resources. Campgrounds are located close to the water's edge, except during periods of deep reservoir drawdowns (primarily in winter). Campground facilities also serve as overflow sites for nearby Glacier National Park. The presence of grizzly bears and bald eagles in the area promotes wildlife observation and photography. The reservoir received approximately 75,000 recreational-use visits during 1987. The primary recreation season is June through August. During 1986, the Self-Guided Tour visitor count at the dam was 34,853, and through October of 1987, it was 31,841 (less than 1986 due to highway construction).

Albeni Falls Reservoir

Activities: Swimming, boating, fishing, camping, sightseeing, picnicking, horseback riding, hunting, and snowmobiling. Albeni Falls Dam regulates the discharge of Lake Pend Oreille, a large natural lake on the Pend Oreille River in northern Idaho. More than half of the land surrounding the lake is privately owned. The remaining shoreline is split among railroad and highway embankment, U.S. Forest Service, U.S. Army Corps of Engineers, and state and municipal ownership. Recreation facilities include private resorts, campgrounds, marinas, boat ramps, swimming and picnicking areas, wildlife management areas, and summer and year-round residences.

A major recreation event each year is the spring Kokanee and Kamloops fishing derby. The derby traditionally coincides with the beginning of the summer fishing season near the end of April, and attracts about 2,000 participants (Lake Pend Oreille, Idaho Club).

Grand Coulee Reservoir

Activities: Boating, fishing, camping, picnicking, hunting, and wildlife observation. (Adjacent land in the Colville and Okanogan National Forests provides additional recreation opportunities, including hiking, fishing, hunting, camping, and horseback riding.) Grand Coulee Dam's Lake Roosevelt is a major recreation area on the Columbia River in eastern Washington State. The reservoir and its shores constitute the Coulee Dam National Recreation Area, extending approximately 150 miles along the reservoir. Recreation facilities, including campgrounds, picnic and swimming areas, marinas, and boat ramps, are owned and operated by the National Park Service or a Park Service concessionaire. The National Park Service estimates there were approximately 800,257 visits to the recreation facilities during 1986 and 1,037,131 visits through November of 1987.

Dworshak Reservoir

Reservoir Activities: Boating, water skiing, camping, picnicking, hiking, hunting, and fishing. Downstream Activities: Bass and steelhead fishing, float trips, swimming and picnicking. Dworshak Dam and Reservoir is situated along the western slopes of the Bitterroot Mountain Range on the North Fork of the Clearwater River in northern Idaho. The reservoir is 54 miles long and, when full, has 184 miles of shoreline.

The dam and lower part of the reservoir are within the Nez Perce Indian Reservation. The area surrounding the project is primarily forest land, including wilderness, scenic, and primitive areas. About three-quarters of the recreation activity occurs during the period June through September.

Recreational facilities along the reservoir are owned and operated by the Corps of Engineers. Facilities include boat launching areas, picnicking and camping sites, and remote camping areas accessible only by boat. Because of downstream recreation uses, the reservoir draft rate and project outflow are important for recreation at this project. Project operating limits (firm constraints) have been established accordingly.

3.2.8.1.2 British Columbia

In British Columbia, the recreational activities associated with the Columbia River system are primarily fishing and hunting. The wildlife in the East Kootenay area are economically important for sport hunting, guide-outfitting, trapping, and tourism. Sport hunting, game guiding, and trapping also occur over much of the Peace River watershed, particularly around Williston Reservoir (Envirocon, 1986).

3.2.8.2 Irrigation

In addition to providing for flood control, power production, and recreation, hydro projects in the Columbia River Basin provide water and power for irrigation. The largest irrigation project in the Basin is the U.S. Bureau of Reclamation's (BOR) Columbia Basin Project, which is authorized to provide irrigation to 1,095,000 acres. Only half of this project has been finished; it currently serves 556,000 acres. Most of the water for the Project is pumped from Grand Coulee (Lake Roosevelt) into Banks Lake, which serves as an equalizing reservoir. Because the pumps for this transfer are located at a fixed elevation in the pumping plant, low reservoir elevations in Lake Roosevelt can cause problems. Approximately 2.3 million acre-feet of water are diverted annually for irrigation at Grand Coulee, with another 20,000 acre-feet annually withdrawn from the Columbia and Snake River confluence. The authorization for withdrawal of Columbia River water to irrigate the second half of the Columbia Basin project will come up for renewal in 1989. The BOR is currently examining several proposals to expand or complete the Project. The maximum irrigation development alternative being considered by the BOR is scheduled for completion in 2027--well beyond the 20-year timeframe studied in this EIS. Of the proposed alternatives which occur during the timeframe of this study, the maximum impact on regional firm power (including the effects of water withdrawals and increased pumping load) would be approximately 50 to 100 MW. The issue of trade-offs between water use for irrigation and power production will be addressed in the BOR's environmental impact statement on Continued Development of the Columbia Basin Project.

3.2.9 CULTURAL RESOURCES

Cultural resources are defined as "the nonrenewable evidence of human occupation or activity as reflected in any district, site, building, structure, artifact, ruin, object, work of art, architecture, or natural feature that was important in human history at the national, state, or local level." Cultural resources which could be affected by Intertie decisions include sites around five storage reservoirs: Albeni Falls (Lake Pend Oreille), Dworshak, Grand Coulee (Lake Roosevelt), Hungry Horse, and Libby (Lake Koocanusa). For purposes of analysis, sites were grouped into locations within successive reservoir elevations of 10 feet. Sites are affected by movement of water into and out of bands of elevations as the reservoir is raised and lowered and by collectors or vandals drawn by artifacts exposed by erosion. A range of elevations was examined for each reservoir, based on current operating ranges:

Libby	2287 - 2459 feet
Hungry Horse	3336 - 3560 feet
Albeni Falls	2049.7 - 2062.5 feet 1/
Grand Coulee	1208 - 1290 feet
Dworshak	1445 - 1600 feet

A description of known cultural resources, by reservoir, follows. Information is from Archeological and Historical Services, 1986.

3.2.9.1 Dworshak

A total of 38 cultural resource sites has been recorded within the Dworshak Reservoir pool. Of these, only five are recorded within the study elevation range. Many sites are inundated under several hundred feet of water. It is estimated that, if a survey were to be conducted along the margins of the reservoir, a substantial number of new sites would probably be recorded. Most investigations were conducted before the raising of the pool level behind the dam (Corliss and Gallagher 1971, 1972; Gaarder 1968; Swanson 1971; Swanson and Corliss 1971). These excavations have documented 8000-plus years of human habitation within the region. Post-inundation studies have been few (e.g., Knudson et al. 1977; Thomas and Mierendorf 1985), although there are indications that the archeological remains that have not been documented within this reservoir may be like those present at Libby Reservoir (see Section 3.2.9.4).

3.2.9.2 Hungry Horse

There has been little archeological research conducted in the Hungry Horse Reservoir to date. Only three sites are recorded at this reservoir; two are at the reservoir margin, and one is completely inundated. More research would be required to estimate the extent of archeological remains at relevant elevation levels for this reservoir.

3.2.9.3 Grand Coulee (Lake Roosevelt)

Most survey work was conducted during the filling of the pool and, afterwards, above the 1,290-foot high water mark (Collier, et al, 1942;

1/ This project sometimes exceeds its normal operating limits. The maximum elevation encountered in BPA studies was 2065.5 feet.

Larrabee and Kardas, 1966). Numerous other sites were found during a spring drawdown in 1967; all were recorded at or above an elevation of 1,240 feet (Chance, 1967).

A total of 166 cultural resource sites 1/ has been identified along the 151 river miles of the Columbia, 30 river miles of the Spokane area, 10 river miles of the Sanpoil arm, and 10 river miles of the Kettle arm comprising the Grand Coulee reservoir. Of these, 97 are prehistoric, 48 are historic, and 21 are both. The 48 historic sites (16 with Smithsonian numbers) were evaluated for this project. Precise locations could not always be assigned. Numerous additional sites had only approximate locations within elevations studied for this project (1,208-1,290 feet). The largest number of sites evaluated for inclusion in the National Register of Historic Places are included in the Kettle Falls Archaeological District (KFAD). This district is located at the northern end of Lake Roosevelt near the town of Kettle Falls. Nineteen sites are identified within the district, 14 containing prehistoric/historic aboriginal components and 2 with historic remains; the remaining sites contain both prehistoric/historic aboriginal and historic EuroAmerican components (Masten and Galm, 1986.)

Sites have been affected by erosion, including landslides and site displacement. Placer mining and relic collecting has also displaced or destroyed sites. Relic collecting, which removes the resource from the public domain, appears to be one of the most significant impacts to occur within the reservoir (Chance, 1967). The cumulative effect is estimated to be severe. The exact condition of many sites is presently uncertain; few sites have been evaluated according to National Register of Historic Places (NRHP) criteria.

Thirty-seven prehistoric and 35 historic sites are anticipated to have research potential based on the documented nature and extent of cultural deposits and features. Twenty-one of the historic sites are townsites, with multi-component deposit potential.

3.2.9.4 Libby (Lake Koocanusa)

Cultural resources investigations since 1950 have recorded 265 prehistoric and historic cultural resources sites (post-inundation). The entire Lake Koocanusa reservoir, including the lands to 2,659 feet above sea level elevation, has been declared eligible for listing in the NRHP as the Middle Kootenai River Archeological District. Many of the sites were exposed during construction and operation of the dam. The most recent major cultural resources field investigations were conducted in 1981 and 1982 and consisted of an intensive, systematic survey and site-testing program of selected sites above 2,342 feet above mean sea level (lowest reservoir elevation for those years). The elevation range considered in the IDU analyses extends below this level. However, earlier studies identified few sites below the 2,342 foot level.

1/ Within the study area and study elevations.

The quality of site data is very high. Sites above 2,342 feet have been thoroughly evaluated and a program outlining future investigations (including data recovery, ongoing monitoring, and site recordation) is being implemented by the Kootenai National Forest and the Seattle District, Army Corps of Engineers. These studies will consider: long-term (9000 BC to Present) trends and changes in human land use; human adaptation at the southern margin of the boreal forest; the beginnings of living in one settled place for hunter-gatherers; subsistence-related burning in the Northern Rockies; Kootenai Indian history and heritage; and historic trading and logging activities. Sites have been affected both before and after inundation, principally from logging, agriculture, excavation, wave-induced erosion, wind erosion, relic collecting, vandalism, and off-road vehicle operation.

3.2.9.5 Albeni Falls (Lake Pend Oreille)

A total of 227 sites has been recorded in the Albeni Falls Reservoir within the bins potentially affected by this project. Thirty-four sites are historic; 172 prehistoric; and 21 sites combine historic and prehistoric components. Site survey began in the 1950s and continued intermittently until 1985, when most of the reservoir was surveyed by Gough and Borenson (1985) and Miss and Hudson (1986). Most of the cultural resources recorded within the fluctuation zone of the reservoir are located on the gently sloping beaches which are generally bordered by low (about .5 to 1 meter) eroding terraces or cut banks.

None of the sites has been submitted to the State Historic Preservation Officer (SHPO) for review or been subsequently determined eligible for inclusion in the NRHP. Of the prehistoric sites recorded, 53 are judged to have research potential (the others cannot be judged due to lack of sufficient information). Most historic sites are extremely marginal because they are isolated artifact scatters or are features lacking meaningful contexts. However, 11 of the sites appear to have a potential for important information within a meaningful historic context (Archeological and Historical Services, 1986). These sites include the Farragut Naval Base; the Pend d'Oreille City Townsite; the Ponderay Smelter; the Bayview Lime Kilns; Lake Mines; the A.C. White Sawmill/Laclede Ferry Landing; the (possible) Markam Homestead (1860s); Seneacquoteen; debris near Seneacquoteen; the Venton Townsite; and (possible) Northern Pacific Railroad construction camps. Of these, Seneacquoteen is most notable and possibly the most historically significant place in northern Idaho north of the Coeur d'Alene mines and the Cataldo Mission.

The greatest impact on these sites has been from erosion. In some instances, as much as 3 feet of the upper deposits of sites has been lost, and there is from 1 to 2 feet (or more) horizontal erosion per year in some areas. Relic hunters contribute to impacts on prehistoric resources as well. Seventy-six percent of all historic sites are located within bins 1 and 2, and are, therefore, already subject to considerable erosion and relic collecting under current operations. Natural deterioration will, nevertheless, continue to have the most significant impacts on historic sites.

3.3 NATURAL RESOURCES ENVIRONMENT

3.3.1 AIR QUALITY 1/

Air quality is a concern in certain defined air basins 2/ and around certain generating plants in the study area (see Appendix A, Figure A.1 for locations of substantially affected generating plants; Table A.10 for California basins affected and Table A.11 for substantially affected coal-fired power plant locations and nearby populations; Table A.12 for populations of affected California Air Basins and Table A.13 for ambient air quality data for areas near affected plants and in California basins). Air quality may be measured in terms of concentrations of pollutants of concern and the extent to which these approach the ambient air quality standards set by the U.S. Environmental Protection Agency (see Appendix A, Table A.14). Pollutants of concern in this analysis are those produced by extracting, processing, transporting, and burning coal, oil, and gas to produce electric power. Principal pollutants produced include sulphur dioxide (SO_2), nitrogen oxides (NO_x), and total suspended particulates (TSP).

In the PNW and ISW, existing SO_2 concentrations in the vicinity of plants whose operations may potentially be affected by Intertie actions are generally low and do not exceed the Primary Standard. TSP levels, on the other hand, do reach or exceed the Primary Standard in a few cases. This is particularly true in rural areas, where dust from unpaved roads and agricultural activities enters the air in large amounts (Biosystems, 1986).

In California, annual basin average concentrations of TSP and SO_2 are comparable to those around PNW and ISW plants. (It should be noted that the PNW and ISW values are representative of air quality in the general vicinity of the generating stations and are higher than regional averages. The values for California, on the other hand, are averages over the air basins.) In most cases in the California basins, power plant emissions represent a small portion of the existing regional emission levels of TSP, but PNW and ISW coal plants may be the main regional sources of both TSP and SO_2 (see Appendix A, Table A.15). NO_x, produced in the combustion of oil, gas, or coal, combines with hydrocarbons in sunlight to produce ozone. In areas with large amounts of sunlight and high hydrocarbon concentrations (such as the Los Angeles Air Basin), ozone becomes a pollutant of concern. Ozone levels average well below the Primary Standard over the PNW and ISW affected areas.

1/ Since operation of British Columbia's single thermal plant would not be affected by any of the proposed actions, no description of air quality in this region is provided.

2/ Three of the subregions for analysis of air quality in California are traditional air basins, which are areas that largely confine the pollutants emitted within them. The pollutants tend to circulate and mix together within the basins.

A related concern is acid deposition. Oxides of nitrogen and sulfur can combine in the air with water to form acid rain or snow which may adversely affect water resources and plant and animal life. A National Acid Precipitation Assessment Program has begun to study sites for acid deposition. Western sites vulnerable to acid deposition include the Cascade Mountains of western Washington, the Sierra Nevada mountains east of San Francisco, the San Francisco Air Basin, the Los Angeles Air Basin, southeastern Arizona, and central Colorado. The link between changing levels of generation and observable impacts of acid deposition is complex and difficult to quantify, depending on many variables such as microclimate, alkalinity of soil and water, and soil depth and composition. (Data on concentrations of components of precipitation related to acid deposition are presented in Appendix A, Table A.16.)

3.3.2 WATER QUALITY AND FISH

The study area includes a wide variety of water resources and fish species. Water resources potentially affected include groundwater supplies, rivers, streams, reservoirs, lakes, ponds, estuaries, marshes, and ocean water. Fish species include the full range dwelling in such water bodies, from the warmest zones in California to the cold waters of British Columbia. Except where specially designated or protected species are involved, therefore, the environmental description for these resources will be generalized by region. Characteristic species are listed in Appendix A, Tables A.17 and A.18.

3.3.2.1 The Hydroelectric System

3.3.2.1.1 Pacific Northwest

Pacific Northwest rivers are host to numerous anadromous fish (species which migrate down the rivers to the ocean, then return upstream to spawn). To complete their journeys, they must negotiate up to nine dams which have impounded most of the free-flowing sections of the Columbia River. Fish journeying to the natural spawning areas in the Snake River and its major tributary, the Salmon River, must pass over eight dams (four on the Columbia; four on the Snake River). Chief Joseph Dam on the Columbia and Hells Canyon Dam on the Snake mark the upstream limits of anadromous fish migration.

The tributaries, lakes, and upper portions of the Columbia River system are the major spawning and nursery grounds for anadromous fish. The principal anadromous fish in the Columbia Basin are steelhead trout; three species of salmon (chinook, coho, and sockeye); and shad. Unlike species of the salmon family (salmonids), however, shad do not inhabit smaller tributaries, but use mostly the mainstem of the Columbia and Willamette Rivers. Other anadromous species include the white sturgeon, striped bass, eulachon, and Pacific lamprey. Anadromous fish, and particularly salmonids, require high-quality water. Water temperature, dissolved oxygen, and nitrogen supersaturation have created the greatest water quality problems for fisheries in the Columbia River Basin.

The Columbia River and its tributaries also contain a variety of resident fish. Resident fish spend their entire life in fresh water, although some regularly migrate fairly substantial distances within the fresh-water system.

Many resident species are relatively tolerant of stressful environmental conditions such as high temperature, low concentrations of dissolved oxygen, and the presence of small amounts of certain toxic pollutants. Anadromous salmonids generally do not tolerate such conditions as well as resident species, especially when such conditions develop quickly. Anadromous fish migration, spawning, and survival of eggs and juveniles are closely linked to water temperature. Flow rates affect the travel rate of both upstream and downstream migrants. Dissolved oxygen concentrations affect the rate of development and growth of eggs, larvae, and juveniles. Effects of toxicants on juvenile salmonids have been studied extensively, and salmonids are known to be generally more sensitive to many pollutants than other groups of fish.

Both anadromous and resident fish have been affected at different stages of their life cycles by the environmental changes created by the existence of hydro projects in the Columbia River system. The following discussion focuses, in turn, on downstream-migrating juvenile salmonids, upstream-migrating adult salmonids, and resident fish.

Downstream Migrants

Downstream migration is greatest during April, May, and June, historically the periods of greatest flow in the mainstem. High flows mean increased spill at most dams, facilitating the passage of juvenile salmonids through the system. Excessive spill, however, may create high dissolved nitrogen levels (nitrogen supersaturation), which is detrimental to both downstream-migrating juveniles and upstream-migrating adults.

Downstream migrants (between 5 and 30 percent) may also pass through dam turbines at each facility. Turbine mortality may result directly or indirectly from injury to the fish from pressure or impact; stunned fish surviving the turbine discharge may be eaten by predators. The type of turbines, efficiency of turbine operation, presence of predator fish, time of passage, and a number of other factors are important variables in determining survival through the powerhouses.

Fish have also been affected by the transformation of what was a fast-moving stream into a series of slow-moving lakes or reservoirs behind dams. Downstream migration time has slowed, and has subjected downstream migrants (particularly juveniles) to considerable biological stress. Migration time is linked to survival in several ways. Prolonged delays expose juveniles to predation and disease and can cause them to lose their time-critical ability to adapt to saltwater when they reach the ocean.

Survival of juvenile fish can also be affected by stranding. When storage reservoirs are rapidly drawn down, small fish may become isolated in discontinuous pools formed as the water recedes. They can become easy prey for birds and animals, or may die as the temperature of shallow pools increases and oxygen is depleted.

Upstream Migrants

Significant otherwise unexplained losses of adult, upstream migrants are attributed to Columbia and Snake River dams. Most adult mortalities due to dams are directly or indirectly linked to delays in migration and seem to be species-related. Some fish ascend the fish ladders provided for upstream passage but allow themselves to pass back over the dam via the spillway ("fallback"). They must then reascend the ladder. Although fallback may occur to some degree at most dams, the problem is especially acute at Bonneville Dam, where fallback has been estimated at between 25 and 35 percent.

Hydropower peaking may also adversely affect upstream passage of adult salmon and steelhead. Peaking operation can cause forebay and tailwater elevation fluctuations beyond design limits of fish passage facilities at dams, which reduce the ladders' ability to attract and pass adult salmonids.

Resident Fish

Resident fish tend to inhabit a particular area of the river (reservoir) for long periods of time (seasonally) or throughout most of their lives. Thus, the distribution and abundance of various species is affected more by local habitat conditions than by general conditions prevailing throughout the river system.

Warm water species, such as the largemouth bass, bluegill, and crappie, are particularly susceptible to reservoir fluctuations. They spawn in the spring when the water warms to about 60 degrees. Nests are constructed in sheltered shallows, near the edges of the reservoirs, at depths from less than 2 feet to about 10 feet. Increases in reservoir fluctuations could change water temperatures or expose nests, killing the eggs.

Resident trout are reared in hatcheries and stocked in many lakes, reservoirs, and streams throughout the Northwest. Most of the easily accessible trout waters are stocked annually because natural production cannot keep pace with demand. Rainbow trout are fairly tolerant of warm temperatures and inhabit the reservoirs and tributary streams throughout the system. Other resident fish inhabit the colder portions, seeking the mouths of cold streams, underwater springs, and cool main currents. Spawning, however, must be accomplished in tributary streams because the reservoirs, except for areas immediately below the dams, do not provide suitable spawning habitat (a gravel substrate with highly oxygenated water percolating through it).

Reservoir waters often favor the establishment and proliferation of nongame species because the new habitat is not ideally suited for establishing a dominant population of either warm- or cold-water game species. In many cases the two habitat types overlap, and warm and cold water species coexist. Reservoir environments which exist today have permitted warm water species to proliferate, although not in great abundance, while spawning populations of trout are confined to the colder tributary streams.

The fish problems associated with Columbia and Snake River dams have been developing for a number of years. In many cases, mitigation for some of the expected fisheries losses was provided at the time of construction. Hatcheries were built or operational funds allocated to rear fish to replace those lost due to inundation of spawning grounds and other causes. The Pacific Northwest Conservation and Power Planning Act (Northwest Power Act) of 1980, which established the Columbia Basin Fish and Wildlife Program, provides guidance to BPA to fund Federal and State agencies, Indian tribes, and private individual proposals to mitigate the loss of fish and wildlife throughout the Columbia River Basin due to hydroelectric projects. These projects include such things as anadromous and resident fish hatchery construction, improvement of fish passage facilities, fish and wildlife habitat enhancement activities, and water requirements to provide adequate flows during critical fish migration periods.

3.3.2.1.2 British Columbia

In the Peace River system of British Columbia, most of the tributary streams support populations of sport fish (Bruce and Starr, 1977) by providing critical spawning and rearing habitat. Numerous species are also found in the Peace River itself and in reservoirs behind dams. Species such as lake whitefish have increased in number since impoundment of their native rivers. By contrast, rainbow trout populations in Williston Reservoir are now declining rapidly. Kokanee salmon are widely distributed, suggesting that large populations may eventually become established throughout the reservoir (Halsey, et al., 1976).

Hydroelectric development projects in the British Columbia portion of the Columbia River system, however, have significantly affected the natural productive capability of fisheries. In particular, the loss of reproductive habitat in tributary streams, elimination of productive littoral areas, and blockage of migration routes have threatened stocks of rainbow trout, Dolly Varden char, kokanee, cutthroat trout, and mountain whitefish (Envirocon, 1986).

The Mica Dam reservoir and its tributaries support populations of Dolly Varden char, rainbow trout, mountain whitefish, burbot, squawfish, and suckers. Duncan Reservoir supports small populations of rainbow trout and Dolly Varden char but is essentially unproductive due to glacial silt conditions. Duncan River, however, provides spawning habitat for the economically important Kootenay Lake rainbow trout and kokanee stocks. Changes in water flow and temperature have threatened these stocks.

Koocanusa Reservoir supports populations of cutthroat trout, Dolly Varden char, mountain whitefish, and burbot. The major loss of stocks has occurred in the main Kootenay River itself. Extreme fluctuations in the flows between winter and summer has reduced the productivity of this area (Envirocon, 1986).

3.3.2.2 Thermal Plants and Water Use

Nuclear and coal-, oil-, or gas-fired generating plants use water for cooling. Water is taken from rivers, aquifers, Pacific coastal waters, or reservoirs, and is recycled within the plant or returned to its source. (A more complete description of the process is found in Section 4.3.3 of this EIS.) Characteristic and/or important fish species in water bodies utilized by generating plants shown in the analysis to be substantially affected by potential Intertie decisions are listed in Appendix A, Table A.18.

3.3.2.2.1 Pacific Northwest

The Yellowstone River in Montana, the Green River in Wyoming, the Skookumchuck River in Washington, and the Columbia River in Oregon, supply water for cooling purposes to Pacific Northwest thermal plants.

The Yellowstone River supports the largest and most important recreational fishery in Southeast Montana, with over 30 species of primarily warm water fish such as catfish and sturgeon in the Forsyth, Montana, area. Precipitation and runoff in the area are low. The river supplies water via pipeline to Castle Rock Reservoir which supports a warm water fishery and is used for the water for the Colstrip coal plant, near Forsyth.

The Green River, near Green River, Wyoming, is regulated at Fontenelle Reservoir. It supports a blue-ribbon fishery for brown and rainbow trout. The river supplies water for the Bridger coal plant. The historical mean annual discharge is 1,763 cfs. Minimum discharge occurs in the winter (688 cfs in February 1984).

The Skookumchuck River, regulated by Skookumchuck Dam, supplies water to the Centralia coal plant. It is a typical Cascade Mountain stream with a full complement of resident and anadromous salmonids (chinook, coho, and chum salmon; steelhead; and cutthroat trout) which use the area near the plant for spawning.

Carty Reservoir, filled with water pumped from the Columbia River, supplies water for irrigation and for cooling the Boardman coal plant. That cooling water is discharged back to the reservoir. The reservoir supports sculpins and smallmouth bass. There is no recreational use of this reservoir.

The Columbia River also supplies cooling water to the WNP-2 nuclear plant and Hanford Generating Project, both at Hanford, and the Trojan nuclear plant near Rainier, Oregon.

Groundwater from the Humboldt River basin supplies the Valmy coal plant in Nevada. The aquifer also supplies domestic consumption and livestock (Biosystems, 1986).

3.3.2.2.2 California

California plants use and return water from and to multiple sources. The Sacramento and San Joaquin Rivers are sources of water for cooling for, respectively, the Pittsburg and Contra Costa plants. The adjoining deltas formed by the rivers and three bays (Suisun, San Pablo, and San Francisco) include 680 miles of navigable channels interspersed with leveed islands used for agriculture. Water resource projects have altered distribution, seasonality, and magnitude of estuary flows here and in nearby salt and brackish marshes. Fresh-water flow into the estuary is less than 40 percent of the natural flow that existed before water diversions, and there is an apparent link between inflow and the capacity of the estuary to assimilate wastes (Nichols et. al., 1986). Several species of anadromous fish (such as chinook salmon, steelhead trout, striped bass, sturgeon, and shad) use these bays and deltas during various life stages. Abundance of many of these species has declined from historic levels in the last decades. Increased export of water from the basin and changing patterns of seasonal flow have contributed to much of this decline. Seasonal flow patterns have changed because the high winter flows are now stored behind dams and subsequently released during the low flow irrigation season (Biosystems, 1986).

Moss Landing Harbor supplies water for cooling at the Moss Landing plant. Water is discharged from units 1 through 5 to Elkhorn Slough, an estuary lagoon with substantial seasonal changes in water quality. The slough is a National Estuarine Research Reserve under administration of the National Oceanographic and Atmospheric Administration (NOAA). Water from units 6 and 7 is also discharged to the Pacific Ocean. The slough and bay support rich estuarine and marine communities, including over 70 species of fish (local species with important sport or commercial values are listed in Appendix A, Table A.18). The slough serves as an important spawning and nursery area for many of these species. It also supports many varieties of shellfish. Since 1983 it has been used as a feeding area by sea otters, a Federally endangered species. The Morro Bay plant is also located in an area with high fish and shellfish populations.

Several plants are located on the Pacific Ocean in southern California. These plants all use once-through cooling systems drawing water from nearshore areas. A high diversity of fish species (see Appendix A, Table A.19) has been found in a study of King Harbor (near the Redondo Beach generating station). This is representative of the El Segundo site as well (J. Stephens, personal communication, May 1987). The species list in Table A.19 was compiled before the 1978 "El Nino" brought warmer conditions to this area. Many of the cold water species (e.g., rockfish and shiner perch) have been replaced by warm water species from further south (J. Stephens, personal communication, May 1987).

The Huntington Beach, Mandalay, and Ormond beach plants are located near areas with flat sandy bottoms and more turbid water than King Harbor. The fish community in these areas is dominated by croaker. The Alamitos plant intake is located in a shallow embayment with a mud and sand bottom. Dominant fish species are croaker and surf perch. The Hunters Point plant draws cooling water from south San Francisco Bay. Current and tides in the area produce a turbulent, well-mixed water mass with salinity near ocean conditions. Dredging and filling in the area have left very little unaltered bottom sediments. Pollution, siltation, and ship wastes have led to a decline in fishery quality.

Two San Bernardino County plants have closed-cycle cooling systems using mechanical draft cooling towers. The Coolwater plant draws groundwater from near Dagget; the Etiwanda plant uses municipal water in Etiwanda. Other uses of groundwater in the area include some agricultural use and domestic use by a Marine Corps base and the City of Barstow.

3.3.2.2.3 Inland Southwest

Rivers and groundwater supply cooling water for ISW power plants. Three plants in Arizona use groundwater for cooling. These plants (Cholla, Coronado, and Springerville) are located in the Plateau Uplands Province. They are the major consumers of groundwater in the area and, when fully developed, will undoubtedly be mining the aquifer (i.e., use by these plants will exceed recharge) (James Marie, personal communication, May 1987). This will cause a decline in water levels in the aquifer and will also deplete flows in the Little Colorado River and local springs.

The Hunter power plant uses water from both Ferron and Cottonwood Creeks in central Utah. The plant uses a closed-cycle, mechanical draft tower cooling system, and has no discharge of waste waters. There is no significant fishery in this area. The waters in these creeks are also used for irrigation.

The San Juan plant in New Mexico uses water from the San Juan River near Fruitland. At this point, the river has been impacted by upstream uses (primarily irrigation) and supports only a small warm water fish population consisting of channel catfish, crappie, threadfin shad, and some bass. This area historically supported Colorado squawfish and razorback sucker (Federally endangered species), and there has been some talk of attempting to re-introduce them (Gary Thorne, personal communication, May 1987).

The Mohave plant (Clark Co., Nevada) uses a closed-cycle cooling system and supplements Colorado River water with water recycled from the coal slurry pipeline supplying the plant. The reservoirs and free-flowing sections of the Colorado River in this area support many uses including recreation, municipal supply, irrigation, and hydroelectric generation. Lake Powell and Lake Mohave support fisheries including striped bass, largemouth bass, smallmouth bass, walleye, rainbow trout, and threadfin shad. Lake Mohave also supports razorback sucker and bonytail chub (a Federally endangered species). The tailwaters of Lake Powell support a major fishery for trophy rainbow trout and brook trout (Bill Silvey, personal communication, May 1987).

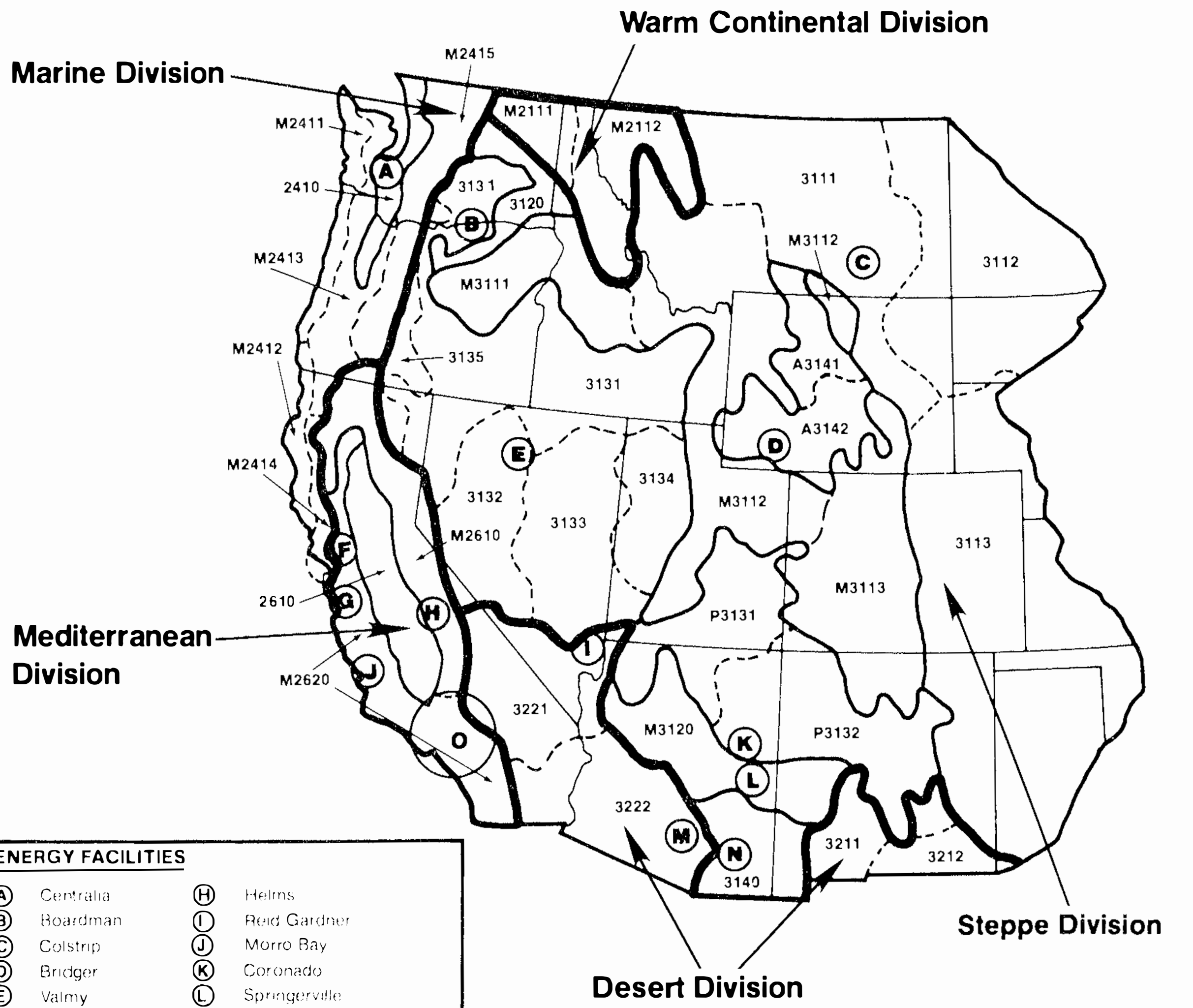
3.3.3 WILDLIFE AND VEGETATION

3.3.3.1 Western United States

Vegetation within the Pacific Northwest, Inland Southwest, and California falls into five general community types--forests/woodlands, shrublands, grasslands, deserts, and riparian/wetland (see Figure 3.7). Each plant community has characteristic associated wildlife types. Because the diversity is so considerable, and because combinations of these communities may occur with an intermixed or "edge" effect, the following discussions will focus on plant communities and associated wildlife.

FIGURE 3.7

LOCATIONS OF ECOSYSTEM REGIONS AND ENERGY FACILITIES



ENERGY FACILITIES

(A) Centralia	(H) Helms
(B) Boardman	(I) Reid Gardner
(C) Colstrip	(J) Morro Bay
(D) Bridger	(K) Coronado
(E) Valmy	(L) Springerville
(F) San Francisco Area Facilities	(M) Irvington
	(N) Apache
(G) Moss Landing	(O) South Coast Facilities

DIVISION
PROVINCE
SECTION

Adapted from Robert G. Bailey, "Ecoregions of the United States," U.S. Department of Agriculture Miscellaneous Publication No. 1391, 1980, 1:7,500,000.

LEGEND

MARINE DIVISION 2400
2410 Willamette-Puget Forest Province
HIGHLANDS
M2410 Pacific Forest Province
- M2411 Sitka Spruce-Cedar-Hemlock Forest Section
- M2412 Redwood Forest Section
- M2413 Cedar-Hemlock-Douglas-fir Forest Section
- M2414 California Mixed Evergreen Forest Section
- M2415 Silver Fir-Douglas-fir Forest Section

MEDITERRANEAN DIVISION 2600
2610 California Grassland Province
HIGHLANDS
M2610 Sierran Forest Province
M2620 California Chaparral Province

STEPPE DIVISION 3100
3110 Great Plains Short-grass Prairie Province
- 3111 Grama-Needlegrass-Wheatgrass Section
- 3112 Wheatgrass-Needlegrass Section
- 3113 Grama-Buffalo Grass Section

3120 Palouse Grassland Province
3130 Intermountain Sagebrush Province
- 3131 Sagebrush-Wheatgrass Section
- 3132 Lahontan Saltbrush-Greasewood Section
- 3133 Great Basin Sagebrush Section
- 3134 Bonneville Saltbrush-Greasewood Section
- 3135 Ponderosa Shrub Forest Section

3140 Mexican Highlands Shrub Steppe Province
HIGHLANDS
M3110 Rocky Mountain Forest Province
- M3111 Grand Fir-Douglas-fir Forest Section
- M3112 Douglas-fir Forest Section
- M3113 Ponderosa Pine-Douglas-fir Forest Section

M3120 Upper Gila Mts. Forest Province
P3130 Colorado Plateau Province
- P3131 Juniper-Pinyon Woodland + Sagebrush-Saltbrush Mosaic Section
- P3132 Grama-Galleta Steppe + Juniper-Pinyon Woodland Section

A3140 Wyoming Basin Province
- A3141 Wheatgrass-Needlegrass-Sagebrush Section
- A3142 Sagebrush-Wheatgrass Section

DESERT DIVISION 3200
3210 Chihuahuan Desert Province
- 3111 Grama-Tobosa Section
- 3212 Tarbush-Creosote Bush Section

3220 American Desert (Mojave-Colorado-Sonoran) Province
- 3221 Creosote Bush Section
- 3222 Creosote Bush-Bur Sage Section

WARM CONTINENTAL DIVISION
HIGHLANDS
M2110 Columbia Forest Province
- M2111 Douglas-fir Forest Section
- M2112 Cedar-Hemlock-Douglas-fir Forest Section

(M) Mountains
(P) Plateau
(A) Altiplano

Specific types will be mentioned only as typifying a group or where species are specially protected. Detailed information on plant communities and wildlife habitat is presented in Appendix A, Table A.20, and lists of characteristic wildlife species are found in Table A.21. (Information following is from Biosystems, 1986.)

3.3.3.1.1 Forest/Woodland and Wildlife

The forest/woodland plant community provides many "layers" of habitat for wildlife, from the ground into the upper branches of older trees. Most vulnerable to change are older stands of trees of various ages, which may take a century or more to develop and thus cannot easily or quickly be replaced.

Large and small mammals, including deer, members of the weasel and skunk family, and rodents such as squirrels and porcupine, are found in the forested areas. Any of these mammals that prefers a narrowly defined habitat can be affected by disturbance or removal of habitat. The forest community, with its many varieties of trees, houses a large number and variety of birds, depending on the region and composition of the forest.

3.3.3.1.2 Shrubland/ Wildlife

Shrublands are located in areas too harsh for forests and/or areas subject to repeated natural disturbances such as floods or fires. They may therefore be more resilient to human disturbances, but may also be replaced by grasslands species if they are disturbed. The major shrubland communities in the area (California Chaparral, Wyoming Basin, and Intermountain Sagebrush) are separated by mountain ranges, and so tend to contain widely differing wildlife communities. They do share adaptable wide-ranging species such as mule deer, coyote, gray fox, mountain lion, and a variety of birds. Each shrubland contains birds and many small mammals and all contain the ermine, a common hunter of these mammals.

3.3.3.1.3 Grasslands/Wildlife

With its tremendous volume of seed-bearing but nonwoody materials, grasslands typically sustain fewer kinds of wildlife, but very large numbers of individual species such as rodents (e.g., ground squirrels). These small mammals attract predators, including hawks. The three predominantly grassland provinces (California Grassland, Palouse, and Great Plains--Shortgrass Prairie) are separated by mountain ranges. Only wide-ranging mammals such as mule deer, coyotes, and badgers occur in all three. Pronghorn antelope and the endangered black-footed ferret (Musteal nigripes) are also found in the Great Plains. Grasslands habitat supports fewer birds because appropriate perching and nesting habitat is sparse.

3.3.3.1.4 Desert/Wildlife

Deserts are harsh and fragile environments in which plant growth rates are slow. Revegetation may take years or decades. The wildlife inhabiting this environment is often very specialized for the harsh conditions, obtaining water from vegetation and avoiding daytime heat by being active primarily at night. Dominant carnivores are small and nocturnal. They include the coyote and spotted skunk, as well as the endangered kit fox (*Vulpes macrotis*) in some areas. Varieties of rodent (such as kangaroo rats and ground squirrels) are fairly common. Areas with cactus or brush may support a variety of birds, especially where water sources allow trees to grow.

3.3.3.1.5 Riparian/Wetland/Wildlife

Riparian/wetland plant communities have very high vegetation and wildlife value. This discussion on riparian vegetation is not classified according to habitat type because of the great diversity along the Columbia and Snake Rivers and their tributaries. These habitat types can range from sand dunes to various types of wetlands. Deer, beaver and other aquatic and terrestrial furbearers, small mammals, waterfowl, upland game birds, reptiles, and amphibians are among the common year-round users of riparian/wetland areas. Wintering elk and moose may also use these areas.

Before dams were built on the Columbia River and its tributaries, riparian vegetation zones developed through natural succession. Many plant species dependent on a high water table or periodic inundation were present. However, some areas subject to natural flooding eroded and were unable to support much vegetation. The flooding of the river valleys as dams were built destroyed much of the original riparian vegetation. In some cases, new vegetation similar to previous types has replaced original vegetation, but it has occurred higher on the shoreline to correspond with the new, higher waterline.

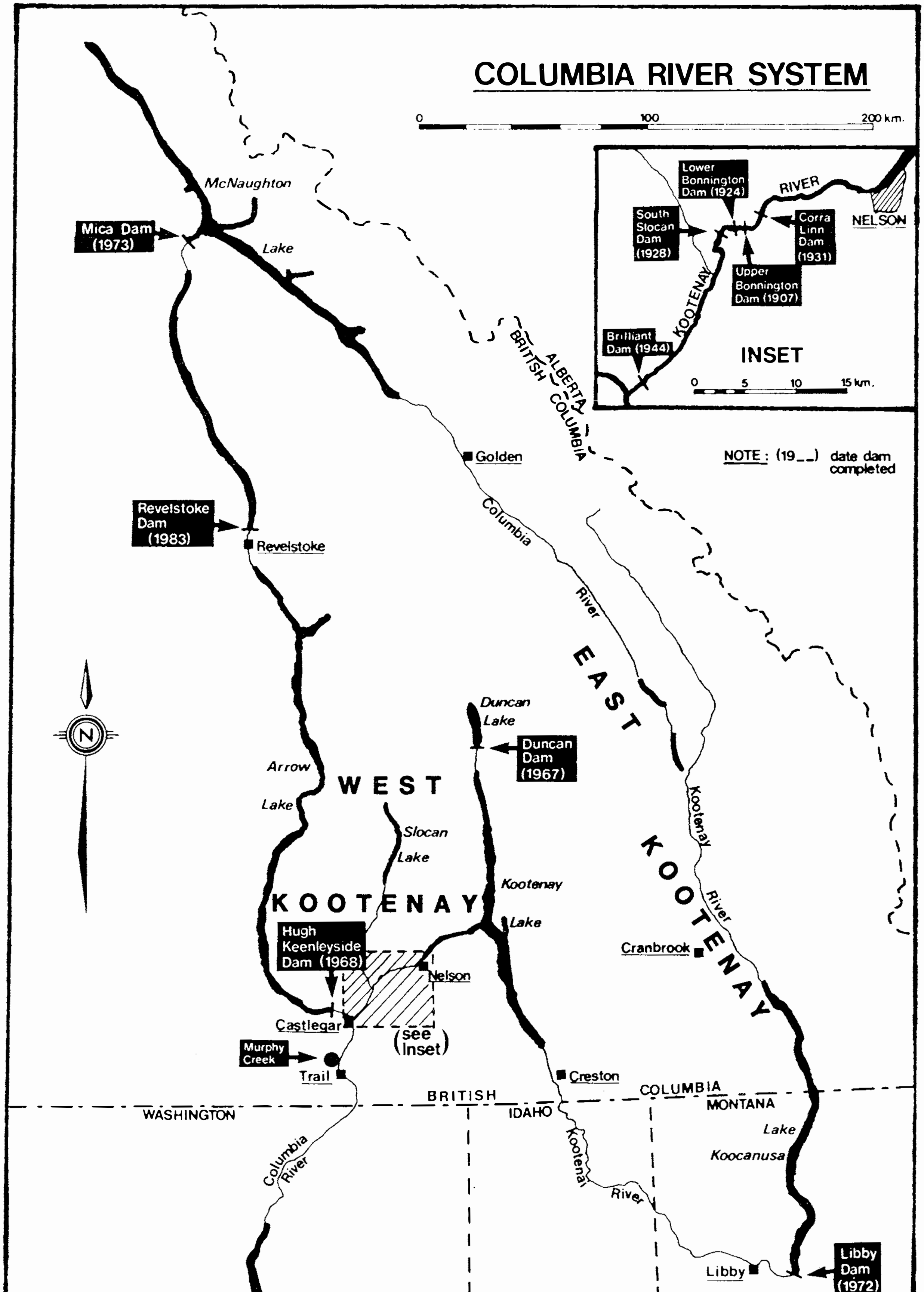
Changes or disturbances to water areas, wetlands, and the high-yield grain crops adjacent to wetlands, contribute to an increase or decrease in wildlife and waterfowl populations and habitat. These changes and disturbances are associated with shoreline construction, water level fluctuations, and shoreline erosion. Shoreline erosion in some areas has created unstable conditions in which vegetation cannot become established. Slides and wave action continuously remove soil and plant materials. Construction efforts to control water erosion have created miles of shoreline covered with rock riprap in which little will grow. Water level fluctuations also have prevented the riparian community from developing, except near the highest pool elevation.

3.3.3.2 British Columbia

The mountains of the Columbia River Watershed in British Columbia produce alternating moist and dry zones across the watershed. Vegetation types vary greatly with elevation, producing a diversity and abundance of wildlife not found elsewhere in the province.

The East Kootenay area (see Figure 3.8) is well known for its big game populations and includes the most highly rated winter ranges in the province. The region contains most of the elk, bighorn sheep, and

FIGURE 3.8


COLUMBIA RIVER SYSTEM
0
100
200 km.
McNaughton
Lake
Mica Dam (1973)
Revelstoke Dam (1983)
Revelstoke
Golden
Columbia River
BRITISH COLUMBIA
ALBERTA
EAST KOOTENAY
WEST KOOTENAY
Arrow Lake
Duncan Lake
Duncan Dam (1967)
Slocan Lake
Kootenay Lake
Kootenay River
Hugh Keenleyside Dam (1968)
Nelson
Castlegar
(see Inset)
Murphy Creek
Trail
Cranbrook
Creston
BRITISH COLUMBIA
WASHINGTON
IDAHO
MONTANA
Columbia River
Kootenai River
Lake Koocanusa
Libby
Libby Dam (1972)
NOTE: (19__) date dam completed
Lower Bonnington Dam (1924)
RIVER
NELSON
South Slocan Dam (1928)
Corra Linn Dam (1931)
Upper Bonnington Dam (1907)
KOOTENAY
Brilliant Dam (1944)
INSET
0
5
10
15 km.
N

white-tailed deer in B.C., and large populations of mule deer, mountain goats, and black bear. Smaller numbers of moose, caribou and grizzly are also present in remote areas. Extensive wetlands and associated lakes in the Rocky Mountain Trench (Columbia Marshes) are used by tens of thousands of migrant waterfowl, several thousand of which stay to nest. These rich marshes are also home to many muskrats, beaver, great-blue herons, ospreys, and bald eagles. Several waterfowl habitat developments have been constructed along the Columbia and Kootenay River valleys. The wildlife in the East Kootenay is economically important for sport hunting, guide-outfitting, trapping, and tourism (Envirocon, 1986).

The West Kootenay area is wetter than the East and receives more snow. Its big game populations are consequently less abundant. Moose are common in the northern portions, and mule deer, elk and white-tailed deer live in the southern valleys. Mountain goats are found throughout the area at higher elevations. Small numbers of caribou and grizzly bear live in remote alpine and subalpine habitats. Black bears and many forest-dwelling furbearers are widespread. The only major wetland complex occurs at Creston, where the province's largest waterfowl habitat development has been constructed. Thousands of swans and other waterfowl stop during migration, particularly in spring, and many ducks, geese, and ospreys nest in or near the controlled marshes. Smaller natural wetlands occur in the valleys of rivers tributary to the Columbia. These and low-gradient streams provide habitat for otter, beaver, a few waterfowl, and other wetland species (Envirocon, 1986).

The moose is the most abundant and economically important big game animal in the Peace River watershed. Near the Williston Reservoir, most low-elevation winter range has been flooded. However, moose populations in the foothills and in nonagricultural parts of the plains are among the highest in the province. Mixed forest/shrub habitats along many of the area rivers provide high-quality winter range for moose. This region contains the only significant deer herds in the northern half of British Columbia. Caribou, Stone's sheep, mountain goats and grizzly bears are present, but not abundant in the western, mountainous parts of the watershed. Sport hunting, game guiding and trapping occur over most of the area (Envirocon, 1986).

Habitat for trumpeter swans, Canada geese, and various ducks is primarily restricted to lakes and marshes on flat uplands east of the foothills. Large numbers of waterfowl move through the Peace River valley during spring migration; however, few of them nest along this or other rivers in the area. Alluvial forest and shrub habitats along major river courses are prime habitats for ruffed grouse, nesting songbirds, and small mammals. Beaver are fairly common in low-gradient river reaches and back channels, and mink and otter also live in these aquatic habitats. A small number of ospreys and bald eagles nest along shorelines of the larger lakes and rivers (Envirocon, 1986).

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ENVIRONMENTAL CONSEQUENCES

Chapter 4

ENVIRONMENTAL CONSEQUENCES

INTRODUCTION

The decisions that BPA will make regarding the development and use of the Intertie represent the initial stage in a series of actions and reactions that could affect the environment. The purpose of this chapter is to describe how BPA analyzed the potential decisions and their potential consequences and to describe the findings.

Chapter 4 begins with a description of how Intertie decisions could affect power exports between British Columbia, the Pacific Northwest, and California. This information is followed by a breakdown of how these sales would affect the types and amounts of generation facilities operated throughout the study area, including the Inland Southwest. The types of resources include hydroelectric, coal, nuclear, oil and gas plants, conservation, cogeneration, renewable resources, geothermal, and pumped storage facilities. This information provides the foundation for the analysis of environmental and economic impacts that makes up much of the rest of Chapter 4. The chapter closes with a presentation of the anticipated effect of Intertie decisions on the need for new generation resources and a discussion of the economic aspects of the proposed actions.

The effects of Intertie decisions on sales levels and on generation by resource type are presented for all types of resources in the first section of this chapter. This format makes it easier to evaluate how such decisions may influence the mix of resources operated to serve loads. However, for purposes of analyzing the effects on factors in the physical environment (e.g., air quality, water quality, consumption of nonrenewable resources, and fisheries), the presentation focuses first on hydroelectric resources and subsequently on thermal resources. This presentation results in a more efficient discussion of impacts peculiar to hydroelectric versus thermal facilities, since they tend to be quite different.

The discussion of the effects of potential changes in hydroelectric plant generation begins with a discussion of how such changes could affect spill amounts, flow rates, reservoir levels, and water quality. Next, there is a description of how these operational changes would be expected to affect fish, recreation, irrigation, and cultural resources.

The next major section of Chapter 4 describes the environmental impacts of potential changes in the operation of thermal facilities. It addresses the potential for impacts on air quality, water quality, fisheries, consumption of nonrenewable resources, and wildlife and vegetation.

Before beginning the discussion of how the proposed decisions would be expected to affect power sales, plant operation, and resource development, it is important to explain the general methodological approach used throughout the analysis of Intertie development and use decisions. More information on techniques of analysis specific to particular environmental factors is presented as appropriate throughout Chapter 4.

The analyses were designed to account for the effects of three distinct, but related decisions dealing with Intertie capacity, formula allocation of hourly access to the Intertie, and long-term firm marketing arrangements. Several alternatives, or conditions, were examined for each of these potential decisions. As indicated in earlier chapters, Intertie capacity was considered at four different levels: 5,200 MW; 6,300 MW; 6,800 MW; and 7,900 MW. Three formula allocation options were considered: the Pre-IAP, the Proposed Formula Allocation, and Hydro-First methods. Finally, three marketing scenarios were considered: Existing Contracts, Federal Marketing, and Assured Delivery. A discussion of these variables was presented in Chapter 2, and additional detail on the alternative formula allocation and contract conditions is contained in Appendix B; Parts 4 and 5.

Given the three major Intertie decisions (and the various options for each), it is possible to develop 4 (Capacity) x 3 (Formula Allocation) x 3 (Marketing) or 36 unique combinations of decision values. However, since some combinations are either impractical or highly unlikely (for example, limiting marketing to the Existing Contracts condition while according access for economy energy under the Pre-IAP formula allocation option and expanding the Intertie to maximum capacity), the number of decision cases analyzed was narrowed to 20. Table 4.0.1 identifies the cases that were selected for analysis.

Table 4.0.1

INTERTIE DECISION SCENARIOS

Formula Allocation/Marketing Options	Capacity Options			
	Existing (5200 MW)	DC Upgrade (6300 MW)	Third AC (6800 MW)	Maximum (7900 MW)
Pre-IAP				
Existing Contracts	•			
Federal Marketing	•			•
Assured Delivery	•			•
Proposed Formula Allocation				
Existing Contracts	•	•		•
Federal Marketing	•	•		•
Assured Delivery	•	•	•	•
Hydro-First				
Existing Contracts	•			
Federal Marketing	•			•
Assured Delivery	•			•

The number of variables involved in evaluating the environmental, social, and economic impacts of BPA's Intertie decisions has required a great deal of complex analysis. Therefore, it is especially important at this point to provide a clear explanation of the order and logic underlying the material presented in this chapter.

To understand the environmental consequences of the Intertie decisions, a decisionmaker needs to be aware of the full range of potential impacts that could result from various combinations of Intertie decisions. It is also important to understand how any one decision might contribute to the overall configuration of impacts associated with any given combination of decisions. The analytic structure upon which the presentation of information in this chapter relies attempts to enable the reader to understand the independent effects of each of the decisions addressed in this document.

Throughout Chapter 4, attention will be directed initially to a discussion of the particular techniques of analysis associated with the environmental factor at issue in that section, e.g., air quality. Next, the findings with respect to that factor will be presented in a consistent order, beginning with the effects of Intertie capacity decisions, and then proceeding through a discussion of the effects of alternative formula allocation procedures and, finally, alternative marketing configurations.

When looking at each of these three variables (i.e., capacity, formula allocation, and marketing), the analytic procedures used must be capable of determining the independent effect of each. To accomplish this, one of the variables must be allowed to vary while the other two remain fixed. For example, the capacity analyses identify differences in environmental impacts among study scenarios with different capacity levels, but under identical formula allocation and marketing assumptions. Thus, the effects of the capacity variable can be seen by comparing a study scenario involving existing capacity with scenarios involving expanded capacities; however, in all of the scenarios, the assumed values for formula allocation and marketing remain constant.

In other words, one of the three decision variables would be identified as the independent variable, the other two decision variables would be identified as control variables, and the environmental (or economic) factor would be considered the dependent variable. To provide a systematic order of presentation, the capacity variable is always treated as the independent variable initially, after which the formula allocation and marketing variables, respectively, assume that role.

In each analysis, it was necessary to define the constant value to be assigned to each of the control variables. The choice of value for the control variables was guided by two criteria. First, an effort was made to select a value which would most clearly illustrate any potential environmental effects. For example, the knowledge that the choice of a formula allocation procedure becomes less critical as the size of the Intertie expands would indicate the need to select Existing, rather than Maximum capacity, as the value for capacity in analyses that treat capacity as a control variable and formula allocation as the independent variable.

The second criterion pertains to the probability that Intertie decisions may be implemented. It was assumed preferable to assign to control variables those values which were considered to be the most likely real-life outcomes. For example, it was assumed to be preferable to analyze the impacts of increasing Intertie capacity in the context of the Proposed Formula Allocation option procedure, rather than in the context of either the Pre-IAP or Hydro-First procedures, since the latter two are less likely to actually be implemented.

Hence, as a result of the use of the two criteria, in an analysis treating Intertie capacity as the independent variable, the Proposed Formula Allocation option would be chosen as the control value for the formula allocation decision because of the high probability of its occurrence, while the Existing Contracts marketing case would be selected over Assured Delivery because the Existing Contracts case would more clearly illustrate the effects of capacity differences on hydroelectric operations.

In some cases, it was believed important to test for the possibility of interaction between the capacity, formula allocation, and marketing variables. For example, the effect of the formula allocation choice tends to be greater when Intertie capacity is limited to the 5,200 MW level than when the Intertie is fully expanded to 7,900 MW. To demonstrate this type of impact, it was occasionally necessary to present an analysis of, for example, the formula allocation variable assuming, first, Existing Intertie capacity and a fixed marketing condition, followed by an identical analysis, except that the capacity level was assumed to be 7,900 MW.

In evaluating the impacts of each Intertie decision, a particular combination of values for the decision variables was designated as a base case. This unique combination of values, however, served as a base case only for a selected subset of comparisons. Each subset of analyses contains a unique base case scenario. This base case scenario is then compared with a limited number of test case scenarios in which the control variables remain constant, but the independent variable assumes differing values. Table 4.0.2 contains a list of the base cases and their related test cases used to structure the analyses for Chapter 4.

As Table 4.0.2 shows, the analysis of the independent effect of the capacity variable involved three somewhat different base cases, the first and second of which were compared with two test cases. The third base case was compared with three test cases. In all three base cases, the Proposed Formula Allocation procedure was assumed, due to its high probability of occurrence, and Existing Intertie capacity was assumed. The difference between these base cases was in the value assigned to marketing. In the first base case, the Existing Contracts condition was assumed; in the second, Federal Marketing was assumed; and in the third, Assured Delivery was assumed. The base cases involving Existing Contracts and Federal Marketing were compared with test cases in which

Table 4.0.2

SUMMARY OF STUDY COMPARISONS

Decision Factor	Base Cases			Test Cases		
	Capacity Condition	Formula Allocation	Contract Condition	Capacity Condition	Formula Allocation	Contract Condition
Intertie Capacity	Existing	Proposed	Existing	DC Upgrade	Proposed	Existing
				Maximum	Proposed	Existing
	Existing	Proposed	Fed. Mrkt.	DC Upgrade	Proposed	Fed. Mrkt.
				Maximum	Proposed	Fed. Mrkt.
	Existing	Proposed	Assured Del.	DC Upgrade	Proposed	Assured Del.
				Third AC	Proposed	Assured Del.
				Maximum	Proposed	Assured Del.
Formula Allocation	Existing	Pre-IAP	Existing	Existing	Proposed	Existing
				Existing	Hydro-First	Existing
	Existing	Pre-IAP	Fed. Mrkt.	Existing	Proposed	Fed. Mrkt.
				Existing	Hydro-First	Fed. Mrkt.
	Maximum	Pre-IAP	Fed. Mrkt.	Maximum	Proposed	Fed. Mrkt.
				Maximum	Hydro-First	Fed. Mrkt.
	Existing	Pre-IAP	Assured Del.	Existing	Proposed	Assured Del.
				Existing	Hydro-First	Assured Del.
	Maximum	Pre-IAP	Assured Del.	Maximum	Proposed	Assured Del.
				Maximum	Hydro-First	Assured Del.
Firm Contracts	Existing	Proposed	Existing	Existing	Proposed	Fed. Mrkt.
				Existing	Proposed	Assured Del.
	DC Upgrade	Proposed	Existing	DC Upgrade	Proposed	Fed. Mrkt.
				DC Upgrade	Proposed	Assured Del.
	Maximum	Proposed	Existing	Maximum	Proposed	Fed. Mrkt.
				Maximum	Proposed	Assured Del.

the Intertie capacity was increased from Existing to either DC or Maximum, while the values of the control variables (i.e., formula allocation and marketing) were unchanged from each base. In the third base case, where the Assured Delivery condition is assigned to the marketing variable, the test cases involved increasing capacity to the 6,300 MW (DC Upgrade), 6,800 MW (Third AC Intertie), and 7,900 MW (Maximum) capacity levels, while maintaining constant values for the formula allocation and marketing variables.

Theoretically, it would have been possible to devise up to nine unique base cases for the capacity variable, each of which would include the assumption of Existing Intertie capacity. Each of these 9 could then have been compared with 3 test cases for a total of 27 possible comparisons. The analysis presented here attempts to focus on a subset of those 27 comparisons which is believed to be of most relevance to the decisions at hand. Combinations that were not considered for analysis were assumed to be either unrealistic, or relatively uninformative for decisionmaking purposes.

For example, the first Intertie capacity base case involving Existing capacity, the Proposed Formula Allocation procedure, and Federal Marketing was compared with its associated Maximum Capacity test case. It was not, however, compared with test cases involving only the DC or AC projects by themselves. It was assumed that the Existing versus Maximum Capacity comparison would take into account the range of possible effects and that the distribution of the impacts of the DC and AC projects within that range would be similar to the distribution illustrated by the more comprehensive set of comparisons involving the second base case, which uses Assured Delivery as the control variable value for marketing. Similar logic was applied in selecting the base and test cases listed in Table 4.0.2 for the formula allocation and marketing analyses.

The full range of analyses outlined in Table 4.0.2 was undertaken for effects on export sales and the operation of plants by resource type. This information was then used to identify decision scenarios that appear to warrant further scrutiny due to effects on the operation of either hydroelectric or thermal resources. The detailed analysis on environmental factors then focused on these particular scenarios. The results of this analysis are described in the sections dealing with environmental impacts due to changes in the operation of either hydroelectric or thermal facilities.

It should be noted that the analyses pertaining to anadromous fish survival presented in Section 4.2.3 do not follow this particular analytical structure. The primary reason for this is because the values associated with anadromous fish survival analysis must be interpreted only in a relative sense. The survival changes discussed in that analysis are relative only to a single base case and cannot be treated as absolute quantities. Thus, it would not be statistically valid to shift from one base case to another in attempting to define the impacts of various test cases. The universal base case used for the anadromous fish analysis assumes the Existing Intertie, Pre-IAP formula allocation, and Existing Contracts marketing conditions.

In addition to assigning values to each of the Intertie decision variables, BPA's analyses required assumptions concerning a variety of additional modeling parameters. These parameters included such items as forecasted Pacific Northwest and California loads, forecasted California oil and gas prices, and the amount of savings required to induce a California purchaser to displace resources with purchases from the Northwest. The values assumed for each of these parameters can potentially influence the results obtained concerning the effect of the various Intertie decision actions. Since such forecasted values are obviously subject to a certain degree of error, it was believed important to assess how much effect certain magnitudes of error might have on the outcome of the environmental analyses. Consequently, BPA performed a series of "sensitivity" analyses to assess the effects that different assumed values for these parameters might have on study results.

The effects of differences in these types of assumptions were not tested for their effects on all of the environmental or economic factors studied. For example, variables which tended to have an effect on hydroelectric system opertion, but little impact on the operation of thermal facilities, were evaluated only in the context of the sensitivity of those environmental factors affected by the operation of the hydro system (cultural resources, recreation, irrigation, and fish). Assumptions found to have substantial influence on the operation of thermal generating facilities were considered in the context of the air quality and nonrenewable resource consumption analyses. A description of the results of relevant sensitivity analyses is included at the end of each section of Chapter 4.

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4.1 POWER SYSTEMS EFFECTS

This section discusses the potential impacts of Intertie decisions on the environment through their effects on: (1) export sales by geographic region; and (2) generation levels by both geographic region and resource type. A discussion of the potential effects of Intertie decisions on the development of new resources can be found in Section 4.4.

OVERVIEW AND SUMMARY

Decisions on Intertie capacity and access policy may affect the amount, timing, and sources of power imported by California. The resulting changes in generating resource operations and construction (including conservation resources) could cause environmental impacts, which are discussed in later sections of this chapter.

A combination of computer models designed to forecast resource development and power system operation are used to assess the potential effects of the proposed actions and their alternatives on export sales, generation, and resource construction. The analysis spans the 20-year period from 1987 through 2006 with data being presented for each of four specific study years (1988, 1993, 1998, and 2003).

The EIS studies predict that the largest and most consistent effect of Intertie decisions on Intertie sales from the Pacific Northwest and Canada to California would be due to Intertie upgrades. As Figure 4.1.1 shows, Intertie sales would increase by about 312 average megawatts (aMW) with the DC Terminal Expansion project, and by about 448 aMW with the Third AC/COTP upgrade. The Maximum upgrade (both actions) would lead to fewer sales than the sum of the effect of each upgrade alone: the Maximum upgrade would lead to about 619 aMW more Intertie sales compared to Existing capacity.

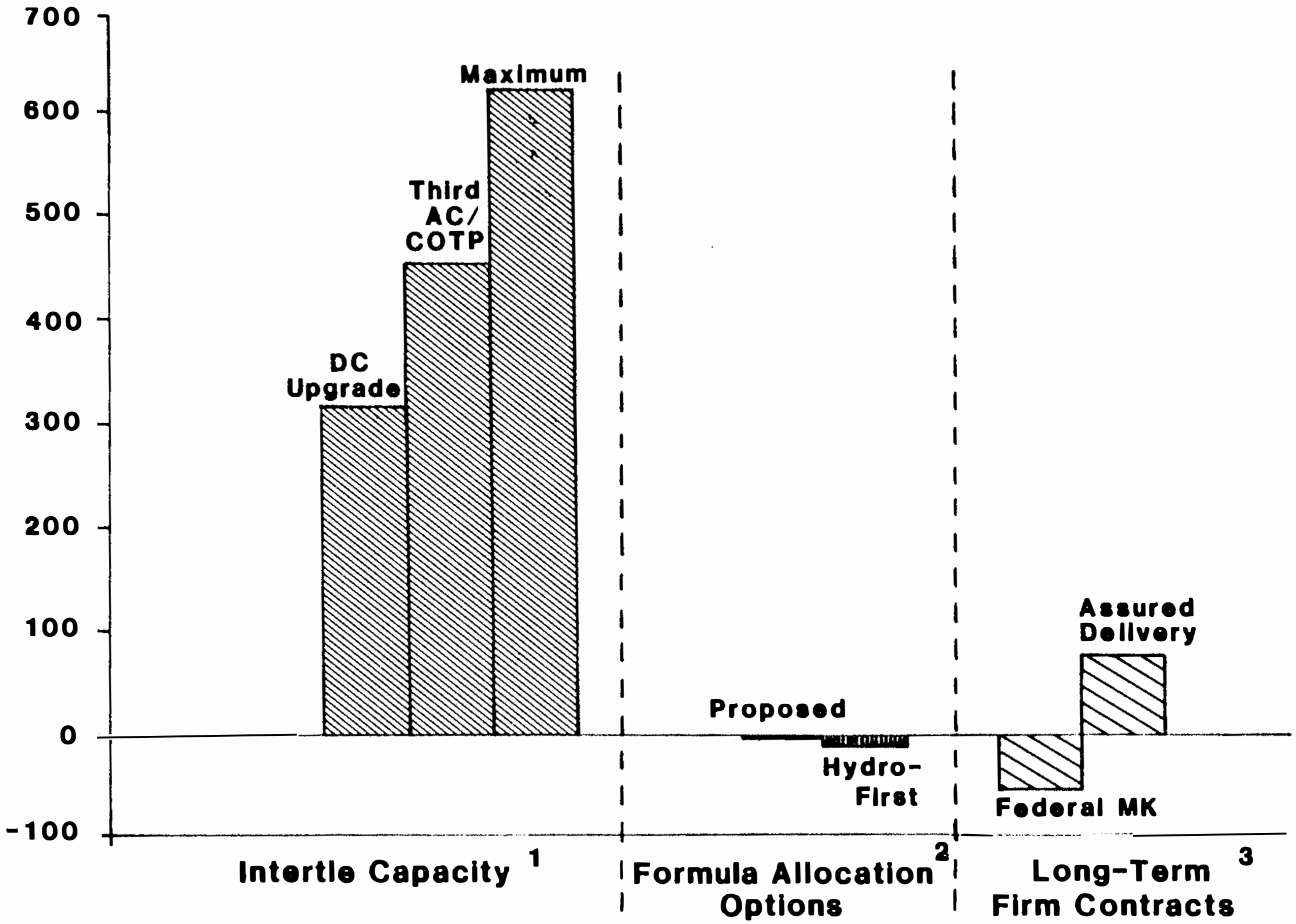
Intertie policy decisions would have a smaller and less consistent effect. Alternatives for providing formula allocation of Intertie access for short-term energy transactions would in some cases lead to small positive, and in other cases, small negative impacts on Intertie sales. Similarly, using the Intertie for long-term firm power transactions would not greatly affect the annual average level of Intertie sales; however, long-term firm contracts would be valuable because they would reduce the cost of resource acquisitions in both regions and lead to higher revenues for the Pacific Northwest.

Figures 4.1.2-4.1.4 show the effect of Intertie decisions on levels of generation by resource type in the PNW, California, and the ISW in a typical study year (1998). Again, Intertie capacity has the largest and most consistent impact on generation levels in each region. In general, as Intertie capacity increases, the Pacific Northwest and Canada increase their Intertie sales through greater generation by hydroelectric resources (in Canada and the PNW) and coal plants (in the PNW). In California, increased imports from the North (i.e., BC Hydro and the Pacific Northwest) allow greater displacement of more expensive resources--primarily oil and gas-fired plants. In addition, if California imported more from the north, it would import less from the Inland Southwest, allowing coal generation (primarily) to be curtailed in the ISW.

Figure 4.1.1

Effects of Intertie Decisions on Export Sales from the PNW and Canada to California (Average of Values for 1988, 1993, 1998, 2003)

(Average MW)

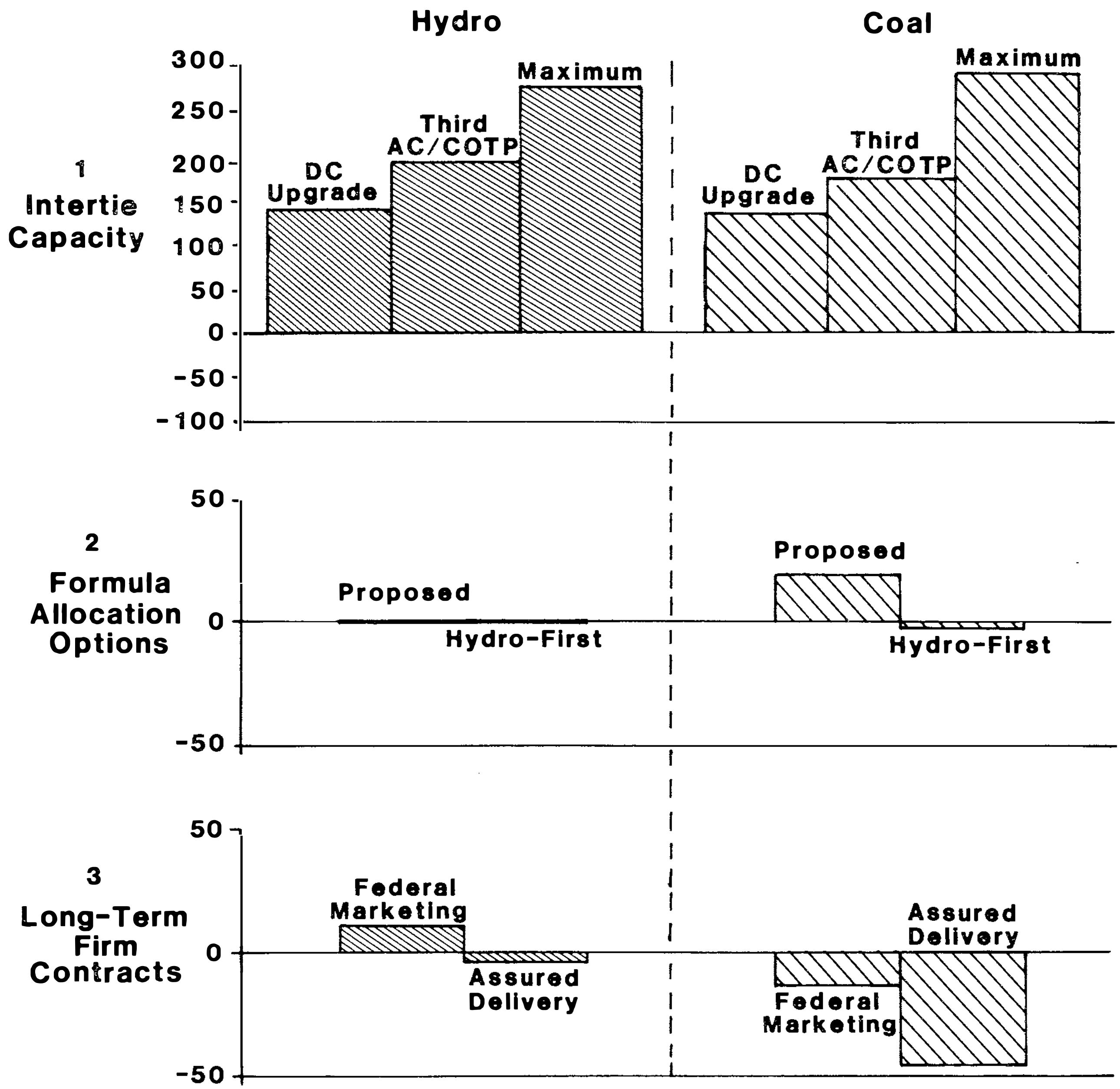


1. Zero Line represents average annual amount assuming the Proposed Formula Allocation Option, Assured Delivery firm contract, and Existing capacity. Bars show change due to Intertie capacity.
2. Shows changes due to formula allocation options, compared to the Pre-IAP option, Assured Delivery firm marketing, and Maximum capacity.
3. Shows changes due to firm marketing options, compared to Existing contracts, Proposed Formula Allocation Option, and Maximum capacity.

Figure 4.1.2

Effects of Intertie Decisions on PNW Generation by Resource Type in 1998

(Average MW)



1. Zero Line represents average annual amount assuming the Proposed Formula Allocation Option, Assured Delivery firm contracts, and Existing capacity. Bars show changes due to Intertie capacity.

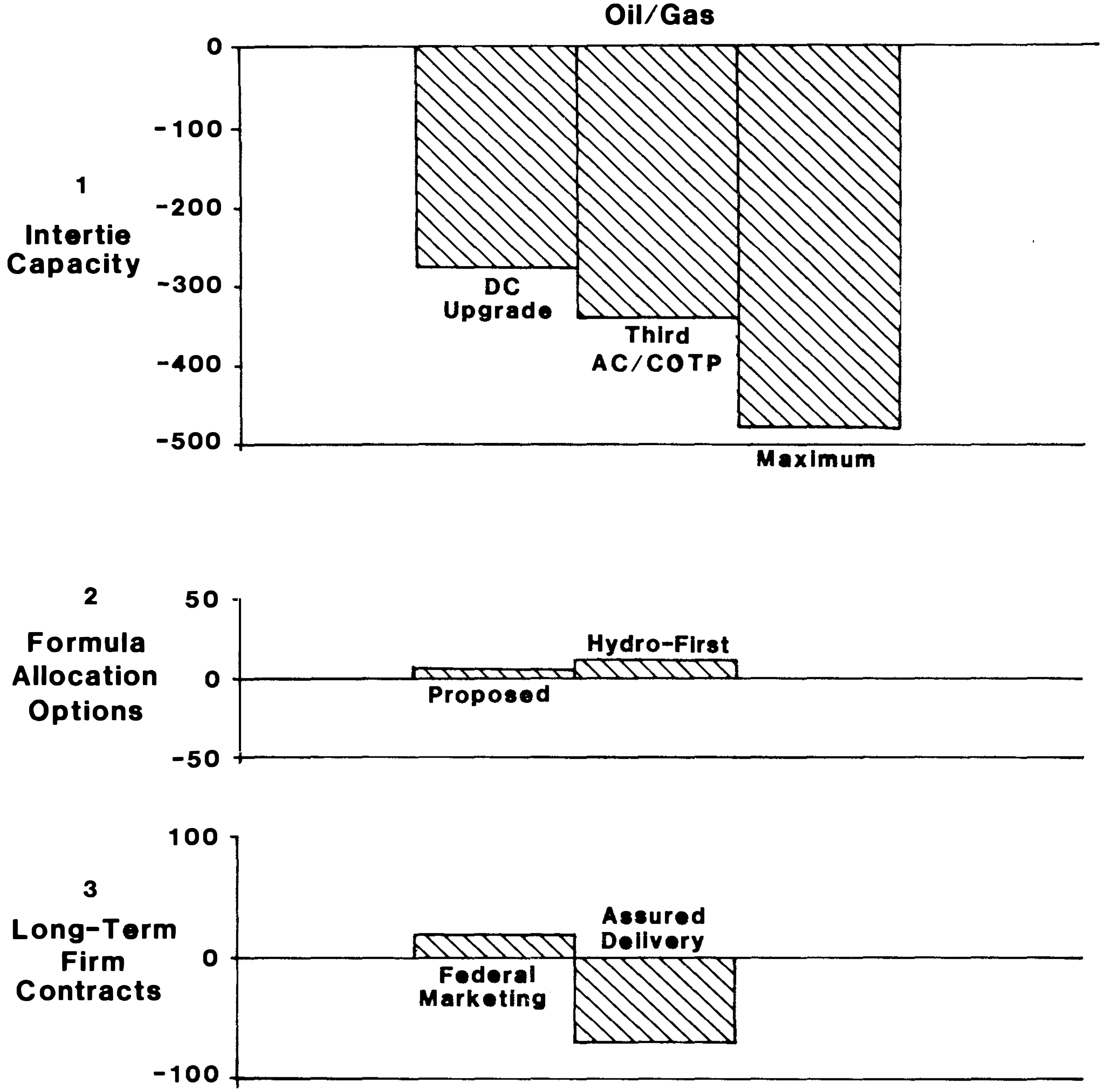
2. Shows changes due to formula allocation options, compared to the Pre-IAP option, Assured Delivery firm marketing, and Maximum capacity.

3. Shows changes due to firm marketing options, compared to Existing contracts, Proposed Formula Allocations Option, and Maximum capacity.

Figure 4.1.3

Effects of Intertie Decisions on California Generation by Resource Type in 1998

(Average MW)



1. Zero Line represents average annual amount assuming the Proposed Formula Allocation Option, Assured Delivery firm contracts, and Existing capacity. Bars show changes due to Intertie capacity.

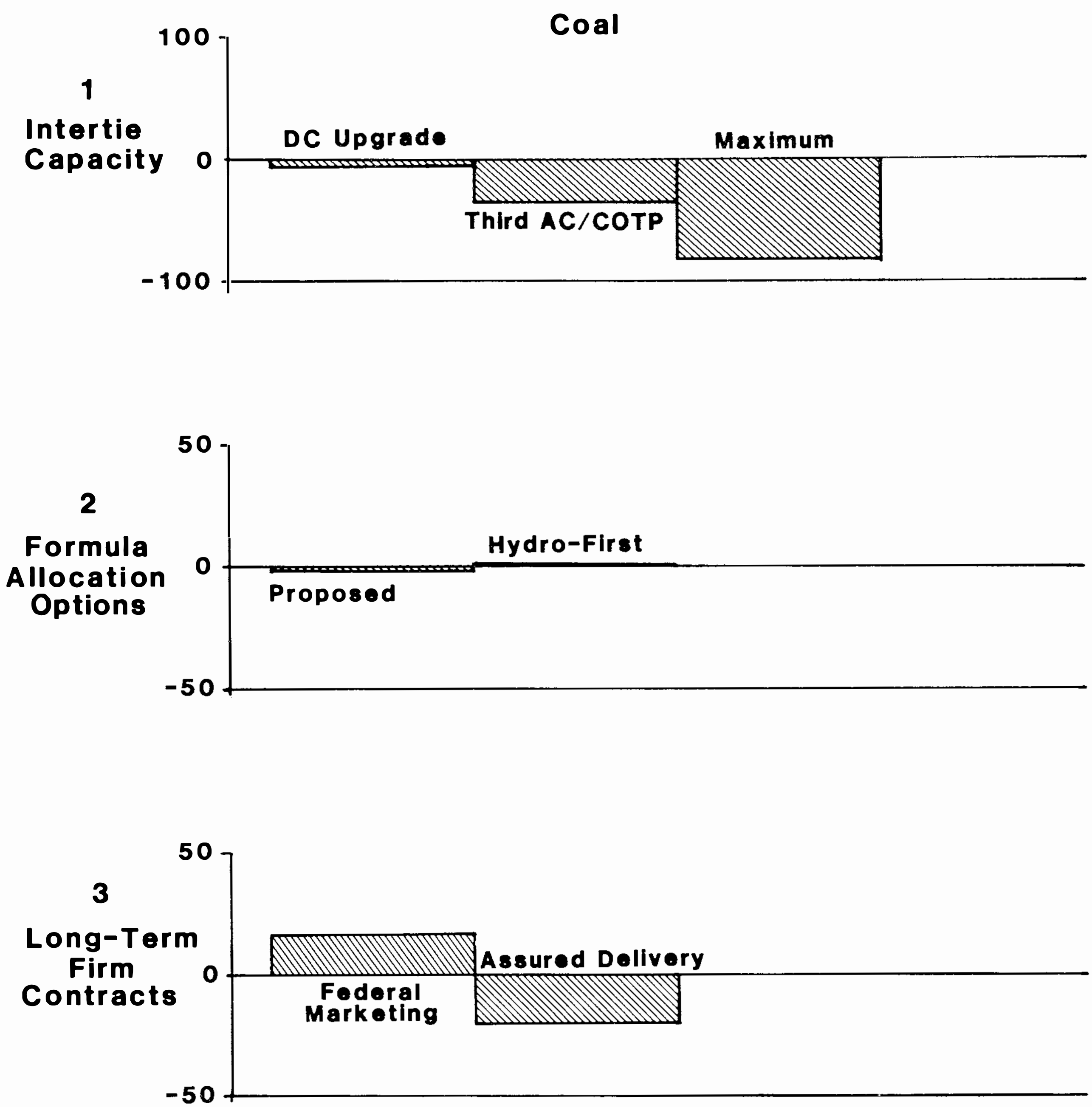
2. Shows changes due to formula allocation options, compared to the Pre-IAP option, Assured Delivery firm marketing, and Maximum capacity.

3. Shows changes due to firm marketing options, compared to Existing contracts, Proposed Formula Allocations Option, and Maximum capacity.

Figure 4.1.4

Effects of Intertie Decisions on ISW Generation by Resource Type in 1998

(Average MW)



1. Zero Line represents average annual amount assuming the Proposed Formula Allocation Option, Assured Delivery firm contracts, and Existing capacity. Bars show changes due to Intertie capacity.

2. Shows changes due to formula allocation options, compared to the Pre-IAP option, Assured Delivery firm marketing, and Maximum capacity.

3. Shows changes due to firm marketing options, compared to Existing contracts, Proposed Formula Allocations Option, and Maximum capacity.

Other Intertie decisions (related to formula allocation options and long-term firm contracts) have generally smaller impacts on the mix of generating resources used to meet load in each region. The largest effect (other than that due to Intertie capacity) stems from the Hydro-First Formula Allocation option. This option would give priority for Intertie sales to surplus hydroelectric energy. The Hydro-First option would generally lead to more hydro generation and less coal generation in the PNW than would either the Pre-IAP or Proposed formula allocation options. Total Intertie sales from the PNW would be somewhat lower, so displacement of higher cost resources in California and the ISW would be slightly less.

4.1.1 ANALYTIC METHODS

The EIS analysis began by simulating export sales for each month in four representative study years. In some of the analyses presented in subsequent sections (e.g., fish studies), monthly data are presented because impacts may vary by month. For much of the analysis, including this section on power system effects, annual summary data are used because annual data provide the most useful summary indications of potential environmental impacts.

The first study year (1988) was selected in order to analyze Intertie conditions before any proposed physical upgrades or additions. In 1988, the Pacific Northwest and Canada would still have substantial amounts of surplus firm energy. The second study year (1993) includes the planned completion of Intertie capacity additions, and reflects anticipated changes in the California system as many independently owned power production facilities (Public Utilities Regulatory Policies Act Qualifying Facilities or QFs) are developed. By the third year (1998), the PNW and Canadian firm energy surpluses are almost gone, and currently planned resources in California have been developed.

The 1998 analysis also includes "generic" resources: those required to meet projected California load growth in and beyond the mid-1990s, but unspecified in utility plans beyond resource type. The last year (2003) examines the effect of alternative Intertie capacities and policies on the development of those "generic" resources. It also allows possible long-range generation impacts to be examined.

The effects on export sales and the operation of generation in British Columbia and the Pacific Northwest were modeled using BPA's System Analysis Model (SAM). Effects on California and Inland Southwest generation were modeled using BPA's Marketing Linear Program Model (Marketing LP). Effects on Northwest new resource development were simulated using BPA's Least Cost Mix Model (LCMM).

4.1.1.1 System Analysis Model

SAM is a computer model developed jointly by BPA and other PNW utilities to improve planning and operation of the coordinated hydroelectric system of the Pacific Northwest and British Columbia. SAM is an operations model: it analyzes how existing and projected resources can be operated most efficiently to meet load. SAM is also a simulation model: it estimates the effect of the many uncertainties involved in electrical system operations by making many simulations for each study period. In the IDU EIS studies, SAM performed 200 simulations for each of the 20 study cases and for each 20-year study horizon (1987 - 2006). In each of the 200 simulations, a different set of historical water conditions, thermal plant outages, and load variation was randomly chosen by the computer. Once selected, the same 200 sets of conditions were used in the analyses of the effects of each Intertie decision. The 200 simulations were used to produce average (expected value) results or probabilities of exceeding specific values for each study scenario.

SAM simulates the operation of PNW resources as they would be dispatched to serve Northwest loads. If there is additional energy available from the region's existing hydro, nuclear, and coal resources, and if a market exists in California to purchase that surplus power at prices economical to both regions, SAM "sells" the surplus power to California, up to available Intertie capacity. In developing these forecasts, SAM takes into account a variety of system operations constraints. Additional constraints were added to the model and, in some cases, existing constraints were modified, in order to simulate the effects of Intertie decisions on resource operations. Appendix B contains information on SAM.

4.1.1.2 Least Cost Mix Model

To operate the PNW's power resources, SAM must know what resources will be available in the future. The Least Cost Mix Linear Program Model (LCMM) solves sets of linear equations to determine the least cost mix of resources to serve the region's firm energy loads, subject to a variety of planning and operational constraints. The LCMM is used to develop a resource schedule as an input to SAM; it can also be used to analyze the effects of Intertie decisions on new resource development in the PNW. Its use in new resource policy analysis is described in more detail in Section 4.4 and in Appendix H.

4.1.1.3 Marketing Linear Program Model

The Marketing LP Model is a linear program (LP) model designed to analyze the most efficient operation of resources throughout the Western United States and Canada in order to serve load. The Marketing LP considers projected loads and resources in major load and generation "centers." Typical centers are Northern California, Southern California, Southern Nevada, Arizona, Utah, and New Mexico. Each center is linked to others in the Western U.S. and Canada by high-voltage transmission lines. The Marketing LP uses "economic dispatch" to determine how much energy should be drawn from or sent to each resource center, within the constraints of existing transmission connections among regions. The output of the Marketing LP predicts generation (by major resource type) within each of the model's centers. Additional information on the Marketing LP is presented in Appendix B, Part 1.

4.1.1.4 ELFIN

In the IDU Draft EIS, BPA contracted with the Independent Power Corporation (IPC) of Oakland, California, to provide analysis of generation levels in California. IPC's principal analytic tool was the

ELFIN (Electrical Financial) model. Upon the completion of the draft EIS, BPA concluded the results of ELFIN were too limited. Although ELFIN simulates great detail for a given utility, it is unable to simulate the interaction (flow of energy from one system to another) among utilities. For this final analysis, BPA used only the Marketing LP for determining California generation because of its strengths in handling flow of energy between regions. Another fundamental change made in the analysis involves grouping of resources. In the IDU Draft EIS, resources were grouped by ownership, regardless of location. For the final analysis, resources have been grouped by regions, e.g., Inland Southwest or California, rather than by ownership.

4.1.2 RESULTS OF QUANTITATIVE ANALYSIS

In the sections that follow, information is presented on the possible effects of Intertie capacity or policy changes on export sales from the PNW, Canada, and the ISW to California. Next, effects on levels of generation by resource type in each region are discussed.

4.1.2.1 Export Sales

In each simulation and year, the amount of PNW surplus energy available to California will depend on several variables that are independent of the proposed decisions or their alternatives. For example, the natural variation in water conditions (on both a seasonal and yearly basis) will result in large swings in the availability of surplus nonfirm energy, because water storage capacity is limited in the Columbia River Basin hydroelectric system. The level of unplanned and planned outages by thermal and hydro plants will also affect the amount of surplus energy in the PNW and Canada. The effects of these factors on sales and generation are far greater than the effects of Intertie decisions. Therefore, differences in sales and generation between study years should be viewed as resulting primarily from these factors and not from the Intertie decisions. Intertie decision effects should be viewed primarily within the context of each study year and not across study years.

Effects of Increasing Intertie Capacity on Export Sales

Table 4.1.1 (all tables in this section are located at the end of the section) shows the effect of Intertie capacity expansion on export sales, including total BC Hydro exports, BC Hydro exports to the Pacific Northwest, BC Hydro exports to California, Pacific Northwest exports to California and total exports to California. This analysis assumes the Proposed Formula Allocation option with Existing Contracts. The results demonstrate a clear pattern. Total BC Hydro exports increase with each upgrade of the Intertie, with the largest increases occurring in 1998 (40 percent) at Maximum capacity. Increases in export sales due to the DC Upgrade always fall in the intermediate range between Existing and Maximum capacity. Sales from BC Hydro to the Pacific Northwest generally decrease with each Intertie upgrade. As Intertie capacity increases, BC Hydro's access to the California market increases. BC Sells more directly to California, leaving less to be sold to displace Pacific Northwest resources. BC Hydro exports to California, on the other hand, increase with each capacity upgrade (up to 62 percent in 1998) as do

Pacific Northwest exports to California (up to 21 percent in 2003). Total exports to California increase with each upgrade; a 23 percent increase in sales occurs in the later study years (1998 and 2003) at Maximum capacity.

A comparison of capacity effects on export sales, given the Proposed Formula Allocation option and either Federal Marketing or Assured Delivery firm contracts, displays the same trends seen in the Existing Contracts cases.

Slight differences in percentage change occur between comparisons due to differences in total exports being made. Total export sales in either the Federal Marketing or the Assured Delivery cases, when compared to total export sales made in the Existing Contracts case, generally increase. Slight increases are observed for total BC Hydro exports, BC Hydro exports to the Pacific Northwest, Pacific Northwest exports to California, and total exports to California, while a slight decrease in total sales occurs in BC Hydro exports to California.

It should be noted that upgrading the Intertie from Existing to Maximum capacity will affect average yearly Intertie sales to California far less than the normal variation in Intertie sales due to changes in the availability of surplus power in the PNW (see Appendix C, Part 1).

Effects of Formula Allocation Options

Table 4.1.2 shows the influence of formula allocation options on export sales, given Existing capacity and assuming, respectively, each of the three firm contract conditions. The effects of the choice of formula allocation are quite similar under each of the contract conditions. Since effects are slightly more pronounced in the Existing Contracts condition, the discussion of allocation effects is presented in this context.

The effect of formula allocation on average annual export sales from each region is variable. With the exception of 1988, total BC Hydro export sales decrease under both the Proposed Formula Allocation and Hydro-First options. In the later years, the Proposed Formula Allocation option displays slightly greater decreases (up to 9 percent) than what is seen in the Hydro-First option (up to 8 percent). Formula allocation effects on BC Hydro exports to the Pacific Northwest show a slightly different pattern. The Proposed Formula Allocation option consistently decreases sales (up to 9 percent) to the Pacific Northwest, while Hydro-First tends to increase sales slightly, with the exception of 1988 when the increase amounts to 30 percent. BC Hydro export sales to California, on the other hand, generally decrease moderately in both the Proposed Formula Allocation and Hydro-First conditions. Again, however, 1988 appears exceptional. In this one year, the Proposed Formula Allocation option produces a sizeable increase (44 percent), and the Hydro-First option a substantial (100 percent) decrease, in BC Hydro's exports to California.

The choice of formula allocation has little if any effect on Pacific Northwest sales to California under any contract condition. Only slight decreases occur in total exports to California, generally in response to the Hydro-First option.

Clearly, results in study year 1988 stand out in the case of BC Hydro exports. There is a 44 percent increase in sales under the Proposed Formula Allocation option, while a 100 percent decrease in sales occurs in the Hydro-First option. Further study of these impacts discloses that in 1988 competition for access in the Pre-IAP case combined with a low-priced California market often causes prices to be below BC Hydro's minimum rate. Thus, in 1988 BC Hydro makes fewer sales under the Pre-IAP condition than under the Proposed condition. Under the Proposed option, the California market has a higher dispatch price and BC Hydro is allowed to bump resources off the Intertie and make sales to California. BC Hydro sales under the Hydro-First option decrease for a completely different reason. The availability of surplus energy in the Pacific Northwest in 1988 and the Northwest's priority in obtaining access to the Intertie, constrain BC Hydro's access, given the limited capacity available on the existing system. As Pacific Northwest surplus decreases and the California market grows, BC Hydro's access in later year increases. BC Hydro exports to the Northwest in 1988 decrease by 9 percent under the Proposed Formula Allocation option, but increase 30 percent under the Hydro-First option. The decrease is likely due to the corresponding decline in Pacific Northwest exports to California and a resulting decrease in the market for exports in the Northwest. The increase in exports to the Northwest under Hydro-First corresponds with BC Hydro's decrease in access to the Intertie.

Table 4.1.3 shows the influence of formula allocation options on export sales given Maximum capacity, and assuming either Federal Marketing or Assured Delivery. The larger capacity size does not appear to change the trend seen in Table 4.1.2, where Existing Contracts at Existing capacity shows variable results for the various export sales being made. The percentage change occurring in the comparison of formula allocation options with either Federal Marketing or Assured Delivery firm contracts remains generally the same.

Again, expected variation in water conditions has a much greater effect on sales than do the allocation options. These study results show that formula allocation options are not a major variable in the average annual volume of total Intertie sales to California.

Effects of Long-Term Firm Contracts

Table 4.1.4 shows the effect of long-term firm contracts on export sales, given the Proposed Formula Allocation option, and assuming each of three capacity levels. BC Hydro total export sales display generally minor and varying results. The moderate reductions in total BC sales evident for Federal Marketing and Assured Delivery in 1988 reflect the reductions in BC Hydro's access due to the combination of capacity limitations, the size of the Northwest surplus and the effect of additional firm sales on the amount of capacity available for hourly allocation.

In the case of BC Hydro exports to the Northwest, a distinct pattern evolves. BC Hydro exports increase in both the Federal Marketing (up to 54 percent) and Assured Delivery (up to 104 percent) cases with Assured

Delivery consistently showing the greater increase in export sales. An opposite pattern occurs in the analysis of BC Hydro exports to California. In this comparison, export sales decrease in both the Federal Marketing (up to 34 percent) and Assured Delivery (up to 57 percent) cases. Again, Assured Delivery shows the greater impact on export sales. Long-term firm contracts have relatively little impact on Pacific Northwest export sales to California, although Federal Marketing tends to produce slight decreases and Assured Delivery small increases in sales.

Total export sales to California vary little in response to the firm contract condition, although sales are slightly higher in the Assured Delivery case (up to 3 percent) and slightly lower in the Federal Marketing case (up to 2 percent).

As in the case of formula allocation effects, the comparison of long-term firm contracts on export sales, given the Proposed Formula Allocation option and either the DC Upgrade or Maximum capacity conditions, generally display the same trends seen in the Existing capacity case. Only slight differences in percentage change occur between comparisons.

Summary of Variation in Export Sales to California

Table 4.1.5 summarizes the range of variation in export sales to California due to the factors of capacity, formula allocation, and long-term firm contracts. For each factor, the maximum difference between cases was calculated. For example, under formula allocation, for each of the study years, the maximum difference among values was determined for the Proposed Formula Allocation and Hydro-First options at Maximum Intertie capacity.

4.1.2.2 Regional Generation Mixes

Changes in export sales to California in response to Intertie decisions will affect the level of generation by existing and planned resources in each of the supply areas (the PNW, BC, and the ISW). Table 4.1.6 shows the thermal plants that the SAM and Marketing LP studies indicate would show significant changes in average annual generation level in response to Intertie decisions. Predicted changes in generation levels are presented below.

4.1.2.2.1 Regional Generation Mix: Pacific Northwest

Changes in Intertie policy or capacity may affect both the level of total generation and the level of generation by each type of resource in the Pacific Northwest. Nearly three-fourths of the PNW's electricity is produced by the region's hydroelectric capacity. In addition, significant amounts of energy (a little over 10 percent of total regional generation) are currently produced at nuclear plants (Hanford Generating Plant, Trojan, and WNP-2). Coal plants (Centralia, Boardman, and the shares of Jim Bridger, Valmy, Corette, and Colstrip dedicated to serve PNW load) supply a little over 13 percent of average annual total generation.

Effects of Variations in the Availability of PNW Power for Export

Variations in the availability of surplus power affect the level of Intertie sales much more strongly than do differences in Intertie policy or capacity. This relationship also explains the interaction of PNW hydro and coal generation. When water is abundant in the PNW, the level of hydro generation increases greatly, and coal generation can be cut back. When water is scarce, coal generation increases. Nuclear plants, because of their low operational costs and high fixed costs, are generally run as baseload, and are not displaced when additional hydro energy is available.

Effects of Increasing Intertie Capacity on PNW Generation

Table 4.1.7 shows the effect of Intertie capacity expansions on Pacific Northwest generation. This analysis assumes the Proposed Formula Allocation option with Existing Contracts. The significant resource generation impacts in this analysis involve hydro and coal. Nuclear, combustion turbines, and, in general, "other" resources that were too small to model explicitly, e.g., small hydro, and PURPA resources, show virtually no response to any of the proposed Intertie actions or their alternatives. With each Intertie upgrade, hydro and coal show increased generation. The Maximum Upgrade always shows the greatest increases (hydro, 2 percent and coal, 12 percent 1/).

The firm contract context in which the capacity analysis is made has little impact on the results. Given either Federal Marketing or Assured Delivery, the same trend occurs. Each capacity upgrade shows increases in generation for both hydro and coal resources with the amounts the same as in the Existing Contract case.

Effects of Formula Allocation Options on PNW Generation

Table 4.1.8 shows the influence of formula allocation options on generation levels in the Pacific Northwest. This analysis assumes Existing Contracts and Existing capacity. Under these conditions, alternative options for allocating access have negligible effects on Pacific Northwest generation. The change in coal generation is variable and minor in both the Proposed Formula Allocation and the Hydro-First option; a decrease or increase in generation of 1 percent occurs. Hydro generation shows virtually no response to changes in formula allocation options.

As was the case for Intertie capacity, the firm contracts context in which the analysis is performed has little impact on the findings. Likewise, as shown in Table 4.1.9, the choice of formula allocation is similarly benign when analyzed in the context of Maximum capacity in either the Federal Marketing or Assured Delivery conditions.

1/ Rounding to the nearest full percentage is used throughout this chapter.

Effects of Long-Term Firm Contracts on PNW Generation

The analysis of long-term firm contracts effects on Pacific Northwest generation, depicted in Table 4.1.10, assumes the Proposed Formula Allocation option and Existing capacity. In this context, firm contracts have relatively little influence on Pacific Northwest generation. In general, coal and "Other Resources" are the two resources which show changes. There is a similarity between Federal Marketing and Assured Delivery effects on coal generation. In the early study year (1988), coal shows small (2 to 5 percent) increases--Assured Delivery showing a slightly higher increase than Federal Marketing. In the remaining three study years, coal decreases slightly--again, Assured Delivery shows the greater decreases. Other Resources, on the other hand, displays increases in generation throughout the four study years in both the Federal Marketing and Assured Delivery marketing cases, with 1993 showing the maximum impacts (Federal Marketing 6 percent and Assured Delivery 8 percent). This is due to the exchange portion of the seasonal capacity energy exchange being included in the "other" category. As shown in Table 4.1.10, changes in firm contracts at either the DC Upgrade or Maximum capacity levels have no additional impact on generation than what was observed in the Existing Intertie context.

4.1.2.2.2 Regional Generation Mix: California

Changes in PNW surplus sales to California affect the amount of California generation required to serve California load. They also affect the level of exports from the ISW to California.

California's resource generation mix includes substantial shares of hydroelectric power, nuclear, oil/gas, and smaller but increasing amounts of other resources (cogeneration, renewable resources, geothermal, and pumped storage), as shown in Tables 4.1.11-4.1.14. In addition, California utilities purchase substantial amounts of economy energy from the PNW and the ISW.

The manner and extent to which California utilities use power imported from the PNW depend on its price, quantity, and seasonal and annual availability. Generally, California utilities make use of, or dispatch, generating resources based on their marginal operating costs. Generating resources that are less costly to operate are used first, with more expensive resources brought on only as demand increases. This system is referred to as economic dispatch. In a straightforward economic dispatch situation, it is a fairly simple matter for a utility to determine when to use imported economy energy and when to use its own generators.

If operating costs were the only consideration, determining whether to use a utility's own generation or to purchase imported power would be relatively simple. However, dispatch decisions are complicated by several factors. First, there are minimum generation constraints on the operation of thermal plants. Most thermal plants cannot quickly shift from a cold condition to full operation. Thus, if a plant is needed to produce power during a daytime peak period or to provide standby capability to assure system reliability, it must operate at a minimum level during the low demand period of the previous night in order to permit a rapid return to full power. At times, the need to operate some thermal plants at their minimum generation levels limits the amount of economy energy that can be purchased by California utilities during offpeak hours. The magnitude of this constraint varies throughout the year, but is particularly a concern during nighttime hours.

A second factor complicating economic dispatch decisions is the utilities' need to insure system reliability. Utilities prefer to use generating resources that are balanced from the standpoint of geographic location and the mix of fuels and technologies. This reduces the risk associated with overdependence on a limited number of transmission lines or corridors, a particular technology or fuel, or a single large plant. Regulatory agencies often require that utilities rely on a variety of sources of generated and imported power in order to insure reliability.

Other factors further complicate dispatch decisions and limit operating flexibility. California private utilities are required to purchase electricity from independent power producers (Qualifying Facilities, or QFs) pursuant to section 210 of the Public Utility Regulatory Policies Act (PURPA) of 1978 (P.L. 95-617). Generally, QF contracts require that utilities purchase QF power whenever it is available, essentially causing them to be operated as baseload units. Even when cheaper economy energy is available, QFs generally cannot be curtailed.

The interaction of economic considerations and the factors noted above determines the mix of generating resources and imported power used to serve California load, and influences the way that Intertie policy or capacity decisions are likely to affect generation levels in California.

Most of California's hydro capacity is run-of-river, has little storage capacity, and is generally operated whenever there is water to turn turbines. Hydro generation in California is not affected by either the proposed Intertie capacity or policy alternatives (see Tables 4.1.11-4.1.14).

Nuclear power is characterized by high capital costs and very low operating costs, and, as Tables 4.1.11-4.1.14 show, changes in levels of California nuclear generation due to Intertie decisions are negligible. The "other" category in Tables 4.1.11-4.1.14 represents several types of generation--geothermal, cogeneration, solar, and other renewable resources (QFs). As those tables show, generation from QF and "other" resources rarely changes in response to Intertie policy or capacity changes.

In California, changes in Intertie policy or capacity primarily affect the level of oil and gas generation. Most units can switch relatively quickly between the two fuels, and utilities choose between fuels based on relative costs of each fuel and on state policies regarding fuel use. In recent years, most oil and gas units in California have used gas. Because oil and gas units can operate within a wide range of capacity, and because they have rather high fuel costs, utilities typically use imported economy energy to displace generation by oil and gas units. The following discussion of changes in California generation levels due to Intertie policy or capacity changes focuses on changes in the level of oil and gas generation.

Effects of Increasing Intertie Capacity on California Generation

Table 4.1.11 shows the effect of capacity expansion on California generation. This analysis assumes the Proposed Formula Allocation option with Existing Contracts. The significant resource generation changes involve impacts on oil and gas generation. Hydro, nuclear and "other" resources show no response to any of the proposed Intertie actions or their alternatives. With each upgrade of Intertie capacity, oil and gas generation decreases. The Maximum Upgrade always shows the greatest decreases (10 percent in 1998). The same trend occurs when the same comparison is made with Federal Marketing or Assured Delivery firm contracts. Decreases in oil and gas generation continue to decrease with each capacity upgrade. A similar range of decreases in generation occurs in both marketing cases as was noted in the Existing capacity comparison.

Effects of Formula Allocation Options on California Generation

Table 4.1.12 shows the influence of formula allocation options on generation levels in California. This analysis assumes Existing Contracts and Existing capacity. At the Existing capacity, alternative options for allocating access have negligible effects on California generation. A very small percentage change in oil and gas generation occurs in the early study year (1988) only. The Proposed Formula Allocation option tends to decrease oil and gas generation by approximately 1 percent, while the Hydro-First option increases it by 1 percent. Changes in Federal Marketing and Assured Delivery had no further impact on resource generation than was evident in the Existing Contract case.

In Table 4.1.13, which depicts the effect of formula allocation options at Maximum capacity, there are no noticeable impacts on California resources in either the Federal Marketing or the Assured Delivery firm marketing cases.

Effects of Long-Term Firm Contracts on Calfornia Generation

The comparison of long-term firm contracts effects on California generation, (Table 4.1.14), assumes the Proposed Formula Allocation option at Existing capacity. Oil and gas generation increases in the Federal Marketing case, but decreases in the Assured Delivery case. In neither observation were the changes greater than 1 percent. As for changes in generation due to firm contracts at either the DC or Maximum upgrades, the trend remains virtually the same - increasing impacts by a maximum of 2 percent.

4.1.2.2.3 Regional Generation Mix: Inland Southwest

The Inland Southwest includes resources that generate power to serve California. BPA's Marketing Linear Program Model was used to predict generation levels at plants in Southern Nevada, Utah, Arizona, and New Mexico in each of the study years. The analysis found that primarily the higher-cost coal plants, which provide economy energy to California, responded to changes in the level of PNW export sales to California.

Effect of Variations In Availability of PNW Power for Export

Intertie sales vary greatly according to the availability of PNW power for export. In the dry years when the PNW makes few sales to California, sales and generation from the ISW increase. When the PNW experiences a wet year, the opposite occurs (See Appendix C, Part 1).

Effects of Increasing Intertie Capacity on ISW Generation

Table 4.1.15 shows how Intertie capacity level is expected to affect the level of generation by each resource type in the Inland Southwest. In the study years after the Intertie upgrades are in place (1993, 1998, and 2003), each upgrade increment leads to more displacement of coal generation in the ISW. Table 4.1.15 shows the effect of capacity expansions on Inland Southwest generation. This analysis assumes the Proposed Formula Allocation and Existing Contracts. The significant resource generation impacts in this analysis involve only coal generation. Hydro, nuclear, combustion turbines and "other" resources show no response to any of the proposed Intertie actions or their alternatives. With each Intertie upgrade, coal generation decreases. The Maximum Upgrade always shows the greatest decreases (1 percent). Assuming either Federal Marketing or Assured Delivery, the same trend occurs.

Effects of Formula Allocation Options on ISW Generation

Table 4.1.16 shows the influence of formula allocation options on generation levels in the Inland Southwest. This analysis assumes Existing Contracts and Existing capacity. At the Existing capacity, alternative options for allocating access have no effect on Inland Southwest generation. Further analysis of Federal Marketing and Assured Delivery contracts shows similar negligible impacts on Inland Southwest resources, as did formula allocation options at Maximum capacity (Table 4.1.17).

Effects of Long-Term Firm Contracts on ISW Generation

The comparison of long-term firm contracts effects on Inland Southwest generation (Table 4.1.18), assuming the Proposed Formula Allocation option at either Existing, DC, or Maximum capacity has no impacts on Inland Southwest resources.

4.1.3 SENSITIVITY AND OTHER ANALYSES

To check if changes in some principal assumptions that BPA made in performing its analysis would significantly affect the results in a way that might lead to different environmental impacts, or to different decisions regarding the Intertie, BPA performed several sensitivity analyses for the IDU Final EIS. These sensitivity analyses individually tested the effects of assuming (1) a different nonfirm rate cap, one that went into effect after the modeling for the original analysis was performed; (2) a higher gas price for California; (3) a higher California load than was assumed in the original analysis; (4) a lower Pacific Northwest load, and (5) three Assured Delivery alternatives which could occur under the proposed LTIAP. The sensitivity analyses are described in greater detail in Appendix B, Part 6.

Less detailed output was obtained for the sensitivity analyses than for the original analyses, and the sensitivity analyses were done for a much more limited number of cases. In the original analyses, year-by-year differences between cases having alternative sets of Intertie assumptions (i.e., different combinations of Intertie size, formula allocation of hourly access, and firm contract level) were the data used to determine environmental impacts. In most of the sensitivity analyses, the effect of the change in the assumption being tested on the year-by-year differences between cases is the value of interest and is shown on the tables.

The results of the sensitivity analyses relating to PNW resource operations and export sales to the California market are described in this section of the IDU EIS. Where the sensitivity analyses show large enough effects on resource operations or exports for changes in environmental impacts to be of some potential concern, the environmental effects which would occur under the sensitivity analyses are described under the appropriate topic headings throughout Chapter 4.

New Nonfirm Rate Cap. The sensitivity analysis for the new nonfirm rate cap showed that the analysis used for the IDU Final EIS is insensitive to this change in assumptions. There were only small numerical changes in annual generation level differences between the cases examined. There were, similarly, very small effects on differences in exports between the cases examined (see Table 4.19).

Higher California Gas Prices. Changing the assumption about California gas prices has a substantial effect on the results of the analysis. These effects occur in comparisons between cases where Intertie size differences exist; the analysis of impacts of changes in formula allocation does not seem very sensitive to California gas price increases. With Intertie capacity increases between cases, higher gas prices lead to larger increases in PNW export sales and generation than shown under the original analysis with the originally assumed California gas price. Increases in PNW generation between the cases are predominantly the result of coal-fired generation. BC Hydro export sales decrease, presumably because with higher California gas prices, additional PNW coal generation becomes competitive and salable to California markets, and precludes some access by BC Hydro to the California market (see Table 4.20).

Higher California Loads. Changing the analysis to assume higher California loads also has substantial effect on the results of the analysis for 1993. As in the high gas price analysis, these effects also occur in comparisons between cases where Intertie size differences exist; the analysis of impacts of changes in formula allocation does not seem very sensitive to California load size increases. With Intertie capacity increases between cases, higher California loads lead to larger increases in PNW export sales and more generation for 1993 by Pacific Northwest resources than shown under the original analysis with the originally assumed California load size. BC Hydro export sales also increase more.

Increases in coal-fired generation predominate over other changes in PNW resource operation for 1993. The size of these effects is partially a product of the size of the increase of California load assumed for the sensitivity analysis relative to that assumed in the original analysis. If the analysis were repeated using a California load forecast intermediate between that assumed in the original analysis and that chosen for the sensitivity analysis, smaller differences from the results of the base case would be observed.

For 1998 and 2003, the assumption of increased California load size shows much less effect on the results of the analysis. This is a consequence of two factors modeled. Forecasted PNW loads in these years are also higher in both the original and sensitivity analyses, leaving less surplus energy for export and leading to more existing coal generation being used by the PNW. Second, in the sensitivity analysis, there would be some increased rate of resource development for California loads in light of the increased California load forecast assumption. This would have a greater effect in the later years since there would have been more time to add resources, thus tending to reduce the effect of increased California loads (see Table 4.21).

Lower Pacific Northwest Loads. The fourth sensitivity analysis assumed lower PNW loads than for the original analysis. Again, changes in formula allocation do not seem very sensitive to lower Pacific Northwest loads; differences between the cases examined showed only small differences for each year between the original analysis and the sensitivity analysis in which lower PNW loads were assumed. For cases in which Intertie capacity increases, rather large effects are shown when the assumed level of PNW loads is lowered. With this assumption, the analysis shows larger and larger amounts of PNW energy, relative to the results of the original analysis, exported as time progresses. This is because the assumption of lower PNW load growth extends and increases the region's surplus and, as time passes, California demand for energy grows at the same rate as assumed in the original analysis. At the same time, PNW demands are lower than assumed in the original analysis, allowing greater sales to California when there is enough Intertie capacity available. Unlike the sensitivities where California loads or gas prices were assumed to be higher, increases in PNW generation between the original analysis cases and the corresponding sensitivity cases were predominantly in hydrogeneration. This is because the current surplus of hydrogeneration capability is extended (see Table 4.1.22).

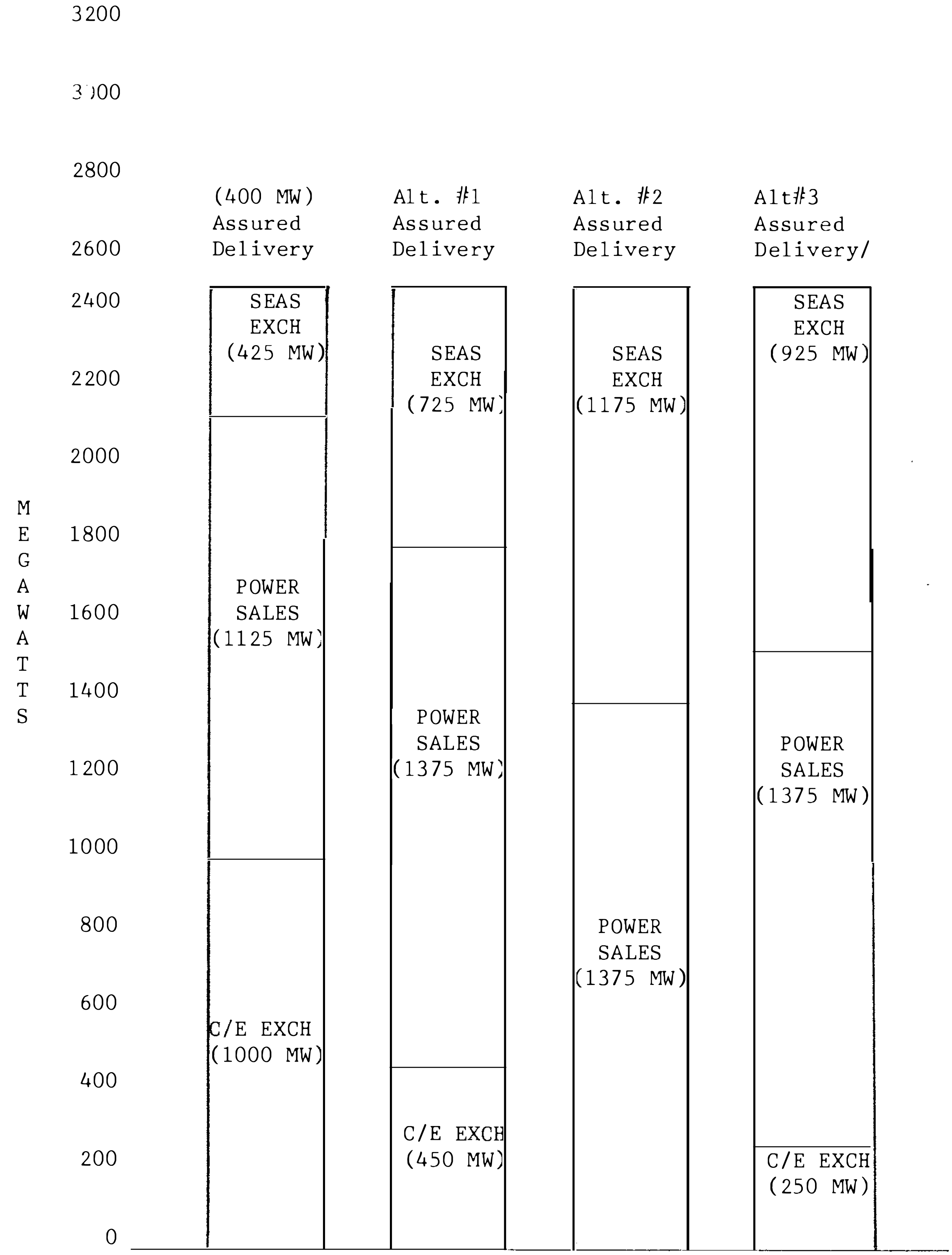
Different Contract Combinations.

Three different Assured Delivery contract configurations were analyzed in addition to the basic Assured Delivery configuration discussed earlier in relation to the Existing and Federal Marketing contract options. The results of these analyses are shown in Table 4.1.23.

The compositions of the original Assured Delivery option, as well as those of the three other contract combinations which could occur under the LTIAP analysed for the sensitivity analyses, are compared in Figure 4.1.5.

Figure 4.1.5

ASSURED DELIVERY CONTRACT COMBINATIONS
(without 600 MW pure capacity contract)



(VS6-PG-1393I)

Alternative 1. This case differs from the Assured Delivery case in the original study in having an additional 300 MW of seasonal power exchanges and an additional 150 aMW of long-term power sales. Capacity/energy exchange transactions were reduced accordingly. Appendix B, Parts 4 and 6 describe the Assured Delivery and Alternatives in detail.

Table 4.1.23 shows the projected differences in Pacific Northwest and BC Hydro export sales and Pacific Northwest generation between the Alternative 1 contract combination and the corresponding values from the original analysis for the Existing Contracts at two Intertie sizes. The Proposed Formula Allocation is assumed in this comparison and is held constant.

If Existing Intertie capacity is assumed for the comparison, the contract combinations studied for the Alternative 1 sensitivity result in relatively small changes in Pacific Northwest generation in the early years of the study. For 1988, PNW coal generation goes up by about 93 aMW, largely to support the additional long-term sale assumed in the sensitivity. In 1993, "Other" generation is higher, but this is a consequence of a one time occurrence of a return of energy under nontreaty storage agreements. For 1998 and 2003, large differences from the original analysis are shown for nuclear generation. If one looks at the year by year results, it can be seen that these differences are resulting from shifts in the projected times that each of two nuclear plants comes on line. The first plant comes on line one year earlier, and the second plant comes on line 2 years earlier with power sales Alternative 1. The amount of Pacific Northwest export sales goes up compared to the original analysis as time passes, while BC Hydro exports go down. This is primarily a consequence of additional firm sales made under the contract. In the early years, the firm sale displaces other nonfirm and surplus firm sales and thus does not lead to a large increase in sales.

If the DC Upgrade is assumed for the comparison, the differences are similar to those observed for the existing Intertie. However, for 1993, less additional Pacific Northwest export sales would occur under Alternative 1 over the Existing Contracts because the DC Upgrade already accounts for some additional exports even with the Existing Contracts. In later years, the difference in Pacific Northwest export sales is even larger than shown for the Existing Intertie comparison. Similar large differences in nuclear generation are shown for 1998 and 2003 for similar reasons. The shifts in when the nuclear plants come on line are the same as for the Existing Intertie comparison.

Alternative 2. Alternative 2 differs from Alternative 1 by elimination of capacity/energy exchange transactions, and an addition of another 450 MW of seasonal exchanges above that in Alternative 1. Otherwise, Alternative 2 is the same as Alternative 1.

Alternative 2 was analyzed assuming Maximum capacity and the Proposed Formula Allocation. The comparison in Table 4.1.23 for Alternative 2 shows similar trends as that for Alternative 1, but the differences in Pacific Northwest export sales are still larger as a consequence of the greater amount of seasonal exchanges in Alternative 2. The shifts in when the nuclear plants come on line remain the same as in the comparison for Alternative 1.

Alternative 3. The third Assured Delivery alternative is a case between Alternatives 1 and 2. In Alternative 3, there are 500 MW more seasonal power exchanges than in the Assured Delivery Alternative. The amount of firm power sales is the same as in Alternative 1 and Alternative 2. The amount of capacity/energy exchanges is 200 MW less in Alternative 3 than in Alternative 1, and 750 MW less than in the Assured Delivery alternative.

Alternative 3 was analyzed assuming the Proposed Formula Allocation at both the DC Upgrade and Maximum Capacity levels. Table 4.1.23 shows similar trends for Alternative 3 for the DC Upgrade Intertie size as Alternative 2 shows with the DC Upgrade. For 1993, Alternative 3 shows 102 aMW of additional total export sales over the Existing Contracts with the DC Upgrade, which is almost the same difference observed for Alternative 1, and the distribution of these exports between BC Hydro and the Pacific Northwest is also almost the same as for Alternative 1. Generation changes between Alternative 3 and the Existing Contracts are small or zero for each type of resource for 1993, but Alternative 3 results in slightly higher reliance on hydro and less reliance on other resources. For 1998 and 2003, Alternative 3 with the DC Upgrade results in substantially more export sales than under the Existing Contracts, and increases the Pacific Northwest's share of those exports slightly. For 2003, there is essentially no difference between Alternative 3 and Alternative 1. However, in export sales or resource operation with the DC Upgrade, for 1998, with the DC Upgrade there is a slight enhancement of Pacific Northwest exports under Alternative 3 relative to that under Alternative 1.

When Maximum Capacity is assumed, Alternative 3 shows the same trends as for Alternative 2 with Maximum capacity, but amounts of exports for each year are somewhat less. Total exports for 1998 and 2003 are enhanced substantially relative to the Existing Contracts case under Alternative 3, but not as much as under Alternative 2. Generation changes from the Existing Contracts case are also very similar for Alternative 3 as for Alternative 2 at Maximum capacity.

Shifts in when the major nuclear plants come on line are the same for Alternative 3 as for Alternatives 1 and 2 regardless of whether the DC Upgrade or Maximum capacity is assumed.

(VS6-PG-1813Z)

Table 4.1.1

EFFECTS OF INTERTIE CAPACITY ON EXPORT SALES
Assuming Proposed Formula Allocation
(Annual Average MWs)

		EXPORT SALES				
		BC HYDRO TOTAL	BC HYDRO TO PNW	BC HYDRO TO CALIF	PNW TO CALIF	TOTAL TO CALIF
Existing Contracts						
1988	Existing Intertie	274	67	207	2876	3083
1993	Existing Intertie	428	109	319	2476	2795
	DC Upgrade	66	-1	67	171	238
	Maximum Upgrade	154	-1	155	280	435
1998	Existing Intertie	328	101	226	2633	2859
	DC Upgrade	83	-13	95	236	331
	Maximum Upgrade	130	-9	139	528	667
2003	Existing Intertie	317	97	220	2656	2876
	DC Upgrade	47	-9	56	274	330
	Maximum Upgrade	86	-12	98	563	661
Federal Marketing						
1988	Existing Intertie	239	103	136	2946	3082
1993	Existing Intertie	430	119	311	2477	2788
	DC Upgrade	68	1	68	160	228
	Maximum Upgrade	126	-4	130	275	405
1998	Existing Intertie	337	117	220	2585	2805
	DC Upgrade	66	-15	81	227	308
	Maximum Upgrade	129	-15	144	519	662
2003	Existing Intertie	332	118	214	2639	2853
	DC Upgrade	42	-14	56	275	330
	Maximum Upgrade	83	-19	103	546	648
Assured Delivery						
1988	Existing Intertie	226	136	90	3012	3102
1993	Existing Intertie	438	151	287	2502	2789
	DC Upgrade	54	-1	56	205	260
	Third AC/COTP	108	-1	108	253	361
	Maximum Upgrade	172	-5	177	283	460
1998	Existing Intertie	328	118	210	2716	2926
	DC Upgrade	53	-3	55	281	336
	Third AC/COTP	75	-12	86	382	468
	Maximum Upgrade	127	-19	147	549	696
2003	Existing Intertie	321	119	202	2754	2956
	DC Upgrade	40	-6	46	295	341
	Third AC/COTP	67	-12	78	437	515
	Maximum Upgrade	91	-18	109	591	700

Source: SAM File (RESSALE.ALL, 29-OCT-1987)

Table 4.1.2

EFFECTS OF FORMULA ALLOCATION OPTIONS ON EXPORT SALES
Assuming Existing Capacity
(Annual Average MWs)

			EXPORT SALES			
		BC HYDRO TOTAL	BC HYDRO TO PNW	BC HYDRO TO CALIF	PNW TO CALIF	TOTAL TO CALIF
Existing Contracts						
1988	Pre-IAP	219	74	144	2910	3054
	Proposed	55	-7	63	-33	29
	Hydro-First	-122	22	-144	51	-94
1993	Pre-IAP	468	112	356	2442	2798
	Proposed	-40	-3	-37	34	-3
	Hydro-First	-16	1	-16	13	-3
1998	Pre-IAP	357	102	255	2614	2868
	Proposed	-29	-1	-29	20	-9
	Hydro-First	-20	0	-20	-7	-26
2003	Pre-IAP	337	97	240	2656	2895
	Proposed	-20	0	-20	1	-19
	Hydro-First	-26	3	-29	-10	-39
Federal Marketing						
1988	Pre-IAP	200	108	92	2972	3064
	Proposed	38	-6	44	-26	18
	Hydro-First	-83	9	-92	28	-64
1993	Pre-IAP	456	122	334	2445	2779
	Proposed	-26	-3	-23	32	9
	Hydro-First	-8	4	-12	7	-5
1998	Pre-IAP	371	118	253	2568	2821
	Proposed	-34	-1	-33	18	-15
	Hydro-First	-18	0	-18	-5	-23
2003	Pre-IAP	354	119	235	2636	2871
	Proposed	-21	-1	-21	3	-18
	Hydro-First	-21	-2	-19	-2	-21
Assured Delivery						
1988	Pre-IAP	186	139	46	3039	3086
	Proposed	40	-3	43	-28	16
	Hydro-First	-40	6	-46	6	-40
1993	Pre-IAP	468	153	315	2472	2787
	Proposed	-30	-2	-29	30	2
	Hydro-First	-11	1	-12	1	-11
1998	Pre-IAP	357	119	239	2695	2934
	Proposed	-30	-1	-29	21	-8
	Hydro-First	-10	0	-10	2	-8
2003	Pre-IAP	342	119	223	2753	2975
	Proposed	-21	0	-21	2	-19
	Hydro-First	-11	0	-11	-5	-16

Source: SAM File (RESSALE.ALL, 29-OCT-1987)

Table 4.1.3

EFFECTS OF FORMULA ALLOCATION OPTIONS ON EXPORT SALES
Assuming Maximum Capacity
(Annual Average MWs)

		EXPORT SALES				
Federal Marketing		BC HYDRO TOTAL	BC HYDRO TO PNW	BC HYDRO TO CALIF	PNW TO CALIF	TOTAL TO CALIF
1993	Pre-IAP	560	122	438	2745	3183
	Proposed	-4	-7	3	7	10
	Hydro-First	-3	0	-3	-8	-11
1998	Pre-IAP	489	103	386	3084	3470
	Proposed	-24	-1	-23	20	-3
	Hydro-First	-15	0	-15	1	-14
2003	Pre-IAP	451	101	350	3167	3517
	Proposed	-36	-2	-34	18	-16
	Hydro-First	-30	-2	-28	4	-24
Assured Delivery						
1993	Pre-IAP	622	152	470	2769	3239
	Proposed	-12	-6	-6	17	10
	Hydro-First	-3	0	-2	-10	-12
1998	Pre-IAP	478	103	375	3250	3624
	Proposed	-23	-5	-18	15	-3
	Hydro-First	-22	-1	-21	-2	-23
2003	Pre-IAP	446	104	341	3327	3669
	Proposed	-34	-3	-30	18	-12
	Hydro-First	-28	2	-27	6	-20

Source: SAM File (RESSALE.ALL, 29-OCT-1987)

Table 4.1.4

EFFECTS OF LONG-TERM FIRM CONTRACTS AT ALTERNATIVE INTERTIE CAPACITIES
ON EXPORT SALES
Assuming Proposed Formula Allocation
(Annual Average MWs)

		EXPORT SALES				
		BC HYDRO TOTAL	BC HYDRO TO PNW	BC HYDRO TO CALIF	PNW TO CALIF	TOTAL TO CALIF
Existing Intertie						
1988	Existing Contracts	274	67	207	2876	3083
	Federal Marketing	-35	36	-71	70	-1
	Assured Delivery	-48	70	-117	136	18
1993	Existing Contracts	428	109	319	2476	2795
	Federal Marketing	2	10	-8	1	-7
	Assured Delivery	10	42	-32	26	-6
1998	Existing Contracts	328	101	226	2633	2859
	Federal Marketing	9	15	-6	-48	-54
	Assured Delivery	0	16	-16	83	66
2003	Existing Contracts	317	97	220	2656	2876
	Federal Marketing	16	21	-6	-17	-23
	Assured Delivery	4	22	-18	98	80
DC Upgrade						
1993	Existing Contracts	494	108	386	2647	3033
	Federal Marketing	5	12	-8	-10	-18
	Assured Delivery	-2	42	-44	60	16
1998	Existing Contracts	410	89	322	2869	3190
	Federal Marketing	-7	13	-20	-56	-77
	Assured Delivery	-30	26	-57	128	72
2003	Existing Contracts	363	87	276	2930	3206
	Federal Marketing	11	17	-7	-17	-23
	Assured Delivery	-2	26	-28	119	91
Maximum Upgrade						
1993	Existing Contracts	582	108	474	2756	3230
	Federal Marketing	-26	7	-33	-5	-37
	Assured Delivery	28	38	-10	29	19
1998	Existing Contracts	457	92	365	3161	3527
	Federal Marketing	8	9	-1	-58	-59
	Assured Delivery	-3	6	-9	103	95
2003	Existing Contracts	402	85	318	3219	3537
	Federal Marketing	13	14	-1	-34	-36
	Assured Delivery	10	16	-7	127	120

Source: SAM File (RESSALE.ALL, 29-OCT-1987)

Table 4.1.5

SUMMARY OF VARIATION IN EXPORT SALES
DUE TO VARIOUS FACTORS
Maximum Difference

		Capacity 1/	Proposed Policy 2/	Hydro-First Policy 3/	Federal Marketing 4/	Assured Marketing 5/
PNW	1988	NA	NA	NA	NA	NA
	1993	283	17	-10	-5	29
	1998	549	15	-2	-58	103
	2003	591	18	6	-34	127
Canada	1988	NA	NA	NA	NA	NA
	1993	177	-6	-2	-33	-10
	1998	147	-18	-21	-1	-9
	2003	109	-30	-27	-1	-7
Total NW	1988	NA	NA	NA	NA	NA
	1993	460	10	-12	-37	19
	1998	696	-3	-23	-59	95
	2003	700	-12	-20	-36	120

1/ Assuming Proposed Formula Allocation and Assured Delivery firm contracts at Maximum capacity.
2/ Assuming Proposed Formula Allocation and Assured Delivery firm contracts at Maximum capacity.
3/ Assuming Hydro-First Policy and Assured Delivery firm contracts at Maximum capacity.
4/ Assuming Proposed Formula Allocation and Federal Marketing firm contracts at Maximum capacity.
5/ Assuming Proposed Formula Allocation and Assured Delivery firm contracts at Maximum capacity.

Table 4.1.6

THERMAL GENERATING RESOURCES IN THE PACIFIC NORTHWEST, INLAND SOUTHWEST, AND CALIFORNIA: SIGNIFICANT CHANGES IN GENERATION LEVEL 1/

Plant Name	Primary Fuel Type	Capacity (MW) 2/
PNW		
Colstrip 1-4	Coal	2,060
Boardman	Coal	530
Centralia 1, 2	Coal	1,280
Jim Bridger 1-4	Coal	2,000
Valmy 1, 2	Coal	522
ISW		
Cholla 1-4	Coal	946
Coronado 1-2	Coal	700
Generic Coal, UT	Coal	418
Springerville	Coal	360
San Juan 1-4	Coal	1,560
Mohave 1-2	Coal	1,580
Hunter 1-3	Coal	1,180
California		
San Francisco	O/G Steam	4,151
Los Angeles	O/G Steam	12,538
San Diego	O/G Steam	1,623
Moss Landing 1-7	O/G Steam	2,060
Morro Bay 1-4	O/G Steam	1,002
Coolwater 1-4	O/G Steam	658
El Centro 1-4	O/G Steam	180

1/ The changes in generation between the PFEXB (no-action case) and alternative scenarios was considered to be significant if there was a 10 MW change, greater or smaller than the no-action case.
2/ Installed capacities (MW) as of January 1, 1986.

Table 4.1.7

EFFECTS OF INTERTIE CAPACITY ON PACIFIC NORTHWEST GENERATION
Assuming Proposed Formula Allocation
(Annual Average MWs)

Existing Contracts		HYDRO	NUCLEAR	COAL	CT	OTHER 1/	TOTAL
1988	Existing Intertie	16133	1930	1991	5	486	20545
1993	Existing Intertie	16015	1538	2794	11	539	20897
	DC Upgrade	98	0	77	0	-15	160
	Maximum Upgrade	182	0	98	0	-26	254
1998	Existing Intertie	16439	1538	2813	13	607	21411
	DC Upgrade	156	0	90	1	0	246
	Maximum Upgrade	259	0	265	0	0	524
2003	Existing Intertie	16315	2335	2913	21	612	22197
	DC Upgrade	136	0	145	1	0	282
	Maximum Upgrade	234	0	339	1	0	573
Federal Marketing							
1988	Existing Intertie	16117	1930	2040	4	486	20577
1993	Existing Intertie	16009	1538	2761	11	573	20892
	DC Upgrade	92	0	73	0	-17	147
	Maximum Upgrade	189	0	91	0	-28	253
1998	Existing Intertie	16479	1538	2777	14	623	21432
	DC Upgrade	135	0	105	1	0	240
	Maximum Upgrade	229	0	290	0	0	520
2003	Existing Intertie	16339	2335	2914	22	629	22239
	DC Upgrade	134	0	152	1	0	287
	Maximum Upgrade	223	0	337	1	1	562
Assured Delivery							
1988	Existing Intertie	16093	1930	2090	4	494	20610
1993	Existing Intertie	16001	1538	2748	12	583	20881
	DC Upgrade	99	0	114	0	-19	194
	Third AC/COTP	142	0	119	0	-25	236
	Maximum Upgrade	202	0	90	0	-30	261
1998	Existing Intertie	16419	1538	2741	15	628	21341
	DC Upgrade	147	0	136	0	0	284
	Third AC/COTP	202	0	183	0	1	386
	Maximum Upgrade	262	0	290	1	1	554
2003	Existing Intertie	16284	2335	2871	22	627	22140
	DC Upgrade	147	0	153	0	0	300
	Third AC/COTP	208	0	239	0	0	447
	Maximum Upgrade	262	0	342	1	1	605

1/ Miscellaneous resources that were too small to explicitly model, small hydro, and PURPA resources.

Source: SAM Files (RESTOT.ALL, 29-OCT-1987) and (BLUEBOOK.OUT, 7-OCT-1987 and 8-OCT-1987)

Table 4.1.8

EFFECTS OF FORMULA ALLOCATION OPTIONS ON PACIFIC NORTHWEST GENERATION
Assuming Existing Capacity
(Annual Average MWs)

Existing Contracts		HYDRO	NUCLEAR	COAL	CT	OTHER 1/	TOTAL
1988	Pre-IAP	16146	1930	2005	4	484	20570
	Proposed	-13	0	-14	1	1	-25
	Hydro-First	7	0	24	-2	1	30
1993	Pre-IAP	16020	1538	2753	11	538	20859
	Proposed	-5	0	41	0	1	37
	Hydro-First	7	0	9	0	-4	12
1998	Pre-IAP	16440	1538	2793	13	607	21391
	Proposed	0	0	20	0	0	20
	Hydro-First	17	0	-23	0	0	-7
2003	Pre-IAP	16314	2335	2913	21	612	22196
	Proposed	1	0	0	0	0	1
	Hydro-First	17	0	-30	0	0	-13
Federal Marketing							
1988	Pre-IAP	16130	1930	2046	4	487	20596
	Proposed	-13	0	-6	0	0	-19
	Hydro-First	-3	0	23	-1	-1	18
1993	Pre-IAP	16017	1538	2720	11	570	20856
	Proposed	-8	0	41	0	3	36
	Hydro-First	6	0	0	0	-5	3
1998	Pre-IAP	16480	1538	2758	14	623	21413
	Proposed	0	0	19	0	0	19
	Hydro-First	8	0	-12	0	0	-4
2003	Pre-IAP	16338	2335	2912	22	629	22236
	Proposed	1	0	2	0	0	3
	Hydro-First	16	0	-17	0	0	-1
Assured Delivery							
1988	Pre-IAP	16104	1930	2104	3	493	20634
	Proposed	-11	0	-15	0	1	-24
	Hydro-First	3	0	-2	0	0	1
1993	Pre-IAP	16009	1538	2710	11	580	20848
	Proposed	-9	0	38	0	4	34
	Hydro-First	6	0	-4	0	-3	-1
1998	Pre-IAP	16419	1538	2719	15	628	21319
	Proposed	0	0	23	0	0	22
	Hydro-First	8	0	-4	0	0	3
2003	Pre-IAP	16284	2335	2870	22	627	22138
	Proposed	1	0	2	0	0	3
	Hydro-First	20	0	-25	0	0	-5

1/ Miscellaneous resources that were too small to explicitly model, small hydro, and PURPA resources.

Source: SAM Files (RESTOT.ALL, 29-OCT-1987) and (BLUEBOOK.OUT, 7-OCT-1987 and 8-OCT-1987)

Table 4.1.9

EFFECTS OF FORMULA ALLOCATION OPTIONS ON PACIFIC NORTHWEST GENERATION
Assuming Maximum Capacity
(Annual Average MWs)

Federal Marketing		HYDRO	NUCLEAR	COAL	CT	OTHER 1/	TOTAL
1993	Pre-IAP	16208	1538	2831	11	543	21131
	Proposed	-9	0	20	0	2	13
	Hydro-First	7	0	-16	0	0	-9
1998	Pre-IAP	16709	1538	3046	15	623	21931
	Proposed	0	0	21	0	0	21
	Hydro-First	4	0	-2	0	0	2
2003	Pre-IAP	16562	2335	3232	22	630	22781
	Proposed	-1	0	19	1	0	19
	Hydro-First	3	0	1	1	0	5
Assured Delivery							
1993	Pre-IAP	16211	1538	2806	11	554	21119
	Proposed	-9	0	33	0	-1	23
	Hydro-First	0	0	-10	0	1	-9
1998	Pre-IAP	16681	1538	3011	15	629	21875
	Proposed	0	0	20	0	0	20
	Hydro-First	0	0	-1	0	0	-1
2003	Pre-IAP	16547	2335	3194	22	627	22725
	Proposed	-1	0	19	1	1	20
	Hydro-First	4	0	2	1	1	7

1/ Miscellaneous resources that were too small to explicitly model, small hydro, and PURPA resources.

Source: SAM Files (RESTOT.ALL, 29-OCT-1987) and (BLUEBOOK.OUT, 8-OCT-1987)

Table 4.1.10

EFFECTS OF LONG-TERM FIRM CONTRACTS AT ALTERNATIVE INTERTIE CAPACITIES
ON PACIFIC NORTHWEST GENERATION
Assuming Proposed Formula Allocation
(Annual Average MWs)

Existing Intertie		HYDRO	NUCLEAR	COAL	CT	OTHER 1/	TOTAL
1988	Existing Contracts	16133	1930	1991	5	486	20545
	Federal Marketing	-16	0	49	-1	0	32
	Assured Delivery	-40	0	99	-2	8	65
1993	Existing Contracts	16015	1538	2794	11	539	20897
	Federal Marketing	-6	0	-33	0	33	-5
	Assured Delivery	-14	0	-46	1	44	-15
1998	Existing Contracts	16439	1538	2813	13	607	21411
	Federal Marketing	40	0	-36	1	16	21
	Assured Delivery	-21	0	-72	2	21	-69
2003	Existing Contracts	16315	2335	2913	21	612	22197
	Federal Marketing	24	0	1	1	17	42
	Assured Delivery	-31	0	-42	1	15	-56
DC Upgrade							
1993	Existing Contracts	16113	1538	2871	11	524	21056
	Federal Marketing	-11	0	-38	0	31	-18
	Assured Delivery	-13	0	-10	1	40	19
1998	Existing Contracts	16595	1538	2903	14	607	21657
	Federal Marketing	19	0	-22	1	16	14
	Assured Delivery	-29	0	-26	1	21	-32
2003	Existing Contracts	16451	2335	3058	22	612	22479
	Federal Marketing	22	0	8	1	17	47
	Assured Delivery	-20	0	-34	1	15	-38
Maximum Upgrade							
1993	Existing Contracts	16197	1538	2892	11	514	21151
	Federal Marketing	2	0	-40	0	31	-7
	Assured Delivery	5	0	-54	0	39	-9
1998	Existing Contracts	16698	1538	3078	13	607	21935
	Federal Marketing	10	0	-11	1	16	16
	Assured Delivery	-17	0	-47	2	22	-40
2003	Existing Contracts	16549	2335	3252	22	613	22770
	Federal Marketing	13	0	-1	1	17	31
	Assured Delivery	-3	0	-39	2	15	-25

1/ Miscellaneous resources that were too small to explicitly model, small hydro, and PURPA resources.

Source: SAM Files (RESTOT.ALL, 29-OCT-1987) and (BLUEBOOK.OUT, 7-OCT-1987 and 8-OCT-1987)

Table 4.1.11

EFFECTS OF INTERTIE CAPACITY ON CALIFORNIA GENERATION
Assuming Proposed Formula Allocation
(Annual Average MWs)

Existing Contracts		HYDRO	NUCLEAR	COAL	OIL/GAS	OTHER 1/	TOTAL
1988	Existing Intertie	4021	3689	0	3621	4346	15677
1993	Existing Intertie	4517	3690	0	3660	7275	19142
	DC Upgrade	0	-1	0	-103	0	-104
	Maximum Upgrade	0	-1	0	-190	0	-191
1998	Existing Intertie	4601	3690	0	4872	8132	21295
	DC Upgrade	0	0	0	-303	0	-303
	Maximum Upgrade	0	0	0	-472	0	-472
2003	Existing Intertie	4602	3690	0	7718	8492	24502
	DC Upgrade	0	0	0	-292	-5	-297
	Maximum Upgrade	0	0	0	-555	-5	-560
Federal Marketing							
1988	Existing Intertie	4021	3689	0	3634	4346	15690
1993	Existing Intertie	4517	3690	0	3684	7275	19166
	DC Upgrade	0	-1	0	-118	0	-119
	Maximum Upgrade	0	-1	0	-185	0	-186
1998	Existing Intertie	4601	3690	0	4921	8132	21344
	DC Upgrade	0	0	0	-271	0	-271
	Maximum Upgrade	0	0	0	-497	0	-497
2003	Existing Intertie	4602	3690	0	7753	8492	24537
	DC Upgrade	0	0	0	-284	-5	-289
	Maximum Upgrade	0	0	0	-545	-5	-550
Assured Delivery							
1988	Existing Intertie	4021	3689	0	3643	4346	15699
1993	Existing Intertie	4517	3690	0	3666	7275	19148
	DC Upgrade	0	-1	0	-111	0	-112
	Third AC/COTP	0	-1	0	-121	0	-122
	Maximum Upgrade	0	-1	0	-187	0	-188
1998	Existing Intertie	4601	3690	0	4809	8132	21232
	DC Upgrade	0	0	0	-284	0	-284
	Third AC/COTP	0	0	0	-335	0	-335
	Maximum Upgrade	0	0	0	-481	0	-481
2003	Existing Intertie	4602	3690	0	7670	8490	24452
	DC Upgrade	0	0	0	-303	-3	-306
	Third AC/COTP	0	0	0	-441	-3	-444
	Maximum Upgrade	0	0	0	-611	-3	-614

1/ "Other" resources include cogeneration, biomass, geothermal, wind, solar, and combined cycle.

Source: Marketing LP File (RPSE.P9800.DCW.IDUEIS.NOV87.SASOUT, 3-NOV-1987)

Table 4.1.12

EFFECTS OF FORMULA ALLOCATION OPTIONS ON CALIFORNIA GENERATION
Assuming Existing Capacity
(Annual Average MWs)

Existing Contracts		HYDRO	NUCLEAR	COAL	OIL/GAS	OTHER 1/	TOTAL
1988	Pre-IAP	4021	3689	0	3645	4346	15701
	Proposed	0	0	0	-24	0	-24
	Hydro-First	0	0	0	54	0	54
1993	Pre-IAP	4517	3690	0	3665	7275	19147
	Proposed	0	0	0	-5	0	-5
	Hydro-First	0	0	0	5	0	5
1998	Pre-IAP	4601	3690	0	4866	8132	21289
	Proposed	0	0	0	6	0	6
	Hydro-First	0	0	0	11	0	11
2003	Pre-IAP	4602	3690	0	7709	8492	24493
	Proposed	0	0	0	9	0	9
	Hydro-First	-1	0	0	33	0	33
Federal Marketing							
1988	Pre-IAP	4021	3689	0	3649	4346	15705
	Proposed	0	0	0	-15	0	-15
	Hydro-First	0	0	0	49	0	49
1993	Pre-IAP	4517	3690	0	3688	7275	19170
	Proposed	0	0	0	-4	0	-4
	Hydro-First	0	0	0	-5	0	-5
1998	Pre-IAP	4601	3690	0	4908	8132	21331
	Proposed	0	0	0	13	0	13
	Hydro-First	0	0	0	18	0	18
2003	Pre-IAP	4602	3690	0	7747	8492	24531
	Proposed	0	0	0	6	0	6
	Hydro-First	0	0	0	9	0	9
Assured Delivery							
1988	Pre-IAP	4021	3689	0	3649	4346	15705
	Proposed	0	0	0	-6	0	-6
	Hydro-First	0	0	0	30	0	30
1993	Pre-IAP	4517	3690	0	3668	7275	19150
	Proposed	0	0	0	-2	0	-2
	Hydro-First	0	0	0	3	0	3
1998	Pre-IAP	4601	3690	0	4799	8132	21222
	Proposed	0	0	0	10	0	10
	Hydro-First	0	0	0	10	0	10
2003	Pre-IAP	4602	3690	0	7658	8490	24440
	Proposed	0	0	0	12	0	12
	Hydro-First	0	0	0	7	0	7

1/ "Other" resources include cogeneration, biomass, geothermal, wind, solar, and combined cycle.

Source: Marketing LP File (RPSE.P9800.DCW.IDUEIS.NOV87.SASOUT, 3-NOV-1987)

Table 4.1.13

EFFECTS OF FORMULA ALLOCATION OPTIONS ON CALIFORNIA GENERATION
Assuming Maximum Capacity
(Annual Average MWs)

Federal Marketing		HYDRO	NUCLEAR	COAL	OIL/GAS	OTHER 1/	TOTAL
1993	Pre-IAP	4517	3689	0	3493	7275	18974
	Proposed	0	0	0	6	0	6
	Hydro-First	0	0	0	8	0	8
1998	Pre-IAP	4601	3690	0	4417	8132	20840
	Proposed	0	0	0	7	0	7
	Hydro-First	0	0	0	11	0	11
2003	Pre-IAP	4602	3690	0	7194	8487	23973
	Proposed	0	0	0	14	0	14
	Hydro-First	0	0	0	28	0	28
Assured Delivery							
1993	Pre-IAP	4517	3689	0	3474	7275	18955
	Proposed	0	0	0	5	0	5
	Hydro-First	0	0	0	7	0	7
1998	Pre-IAP	4601	3690	0	4323	8132	20746
	Proposed	0	0	0	5	0	5
	Hydro-First	0	0	0	14	0	14
2003	Pre-IAP	4602	3690	0	7053	8487	23832
	Proposed	0	0	0	6	0	6
	Hydro-First	0	0	0	17	0	17

1/ "Other" resources include cogeneration, biomass, geothermal, wind, solar, and combined cycle.

Source: Marketing LP File (RPSE.P9800.DCW.IDUEIS.NOV87.SASOUT, 3-NOV-1987)

Table 4.1.14

EFFECTS OF LONG-TERM FIRM CONTRACTS AT ALTERNATIVE INTERTIE CAPACITIES
ON CALIFORNIA GENERATION
Assuming Proposed Formula Allocation
(Annual Average MWs)

Existing Intertie		HYDRO	NUCLEAR	COAL	OIL/GAS	OTHER 1/	TOTAL
1988	Existing Contracts	4021	3689	0	3621	4346	15677
	Federal Marketing	0	0	0	13	0	13
	Assured Delivery	0	0	0	22	0	22
1993	Existing Contracts	4517	3690	0	3660	7275	19142
	Federal Marketing	0	0	0	24	0	24
	Assured Delivery	0	0	0	6	0	6
1998	Existing Contracts	4601	3690	0	4872	8132	21295
	Federal Marketing	0	0	0	49	0	49
	Assured Delivery	0	0	0	-63	0	-63
2003	Existing Contracts	4602	3690	0	7718	8492	24502
	Federal Marketing	0	0	0	35	0	35
	Assured Delivery	0	0	0	-48	-2	-50
DC Upgrade							
1993	Existing Contracts	4517	3689	0	3557	7275	19038
	Federal Marketing	0	0	0	9	0	9
	Assured Delivery	0	0	0	-2	0	-2
1998	Existing Contracts	4601	3690	0	4569	8132	20992
	Federal Marketing	0	0	0	81	0	81
	Assured Delivery	0	0	0	-44	0	-44
2003	Existing Contracts	4602	3690	0	7426	8487	24205
	Federal Marketing	0	0	0	43	0	43
	Assured Delivery	0	0	0	-59	0	-59
Maximum Upgrade							
1993	Existing Contracts	4517	3689	0	3470	7275	18951
	Federal Marketing	0	0	0	29	0	29
	Assured Delivery	0	0	0	9	0	9
1998	Existing Contracts	4601	3690	0	4400	8132	20823
	Federal Marketing	0	0	0	24	0	24
	Assured Delivery	0	0	0	-72	0	-72
2003	Existing Contracts	4602	3690	0	7163	8487	23942
	Federal Marketing	0	0	0	45	0	45
	Assured Delivery	0	0	0	-104	0	-104

1/ "Other" resources include cogeneration, biomass, geothermal, wind, solar, and combined cycle.

Source: Marketing LP File (RPSE.P9800.DCW.IDUEIS.NOV87.SASOUT, 3-NOV-1987)

Table 4.1.15

EFFECTS OF INTERTIE CAPACITY ON INLAND SOUTHWEST GENERATION
Assuming Proposed Formula Allocation
(Annual Average MWs)

Existing Contracts		HYDRO	NUCLEAR	COAL	OIL/GAS	OTHER 1/	TOTAL
1988	Existing Intertie	1852	2780	9882	425	21	14960
1993	Existing Intertie	1997	2780	11307	420	62	16566
	DC Upgrade	0	0	-48	0	0	-48
	Maximum Upgrade	0	0	-147	0	0	-147
1998	Existing Intertie	2002	2780	13629	420	74	18905
	DC Upgrade	0	0	-2	0	0	-2
	Maximum Upgrade	0	0	-82	0	0	-82
2003	Existing Intertie	2002	2780	15734	364	74	20954
	DC Upgrade	0	0	-10	0	0	-10
	Maximum Upgrade	0	0	-51	0	0	-51
Federal Marketing							
1988	Existing Intertie	1852	2780	9835	425	21	14913
1993	Existing Intertie	1997	2780	11322	420	62	16581
	DC Upgrade	0	0	-54	0	0	-54
	Maximum Upgrade	0	0	-137	0	0	-137
1998	Existing Intertie	2002	2780	13626	420	74	18902
	DC Upgrade	0	0	3	0	0	3
	Maximum Upgrade	0	0	-62	0	0	-62
2003	Existing Intertie	2002	2780	15730	364	74	20950
	DC Upgrade	0	0	-9	0	0	-9
	Maximum Upgrade	0	0	-52	0	0	-52
Assured Delivery							
1988	Existing Intertie	1852	2780	9815	425	21	14893
1993	Existing Intertie	1997	2780	11338	420	62	16597
	DC Upgrade	0	0	-83	0	0	-83
	Third AC/COTP	0	0	-153	0	0	-153
	Maximum Upgrade	0	0	-181	0	0	-181
1998	Existing Intertie	2002	2780	13608	420	74	18884
	DC Upgrade	0	0	-7	0	0	-7
	Third AC/COTP	0	0	-46	0	0	-46
	Maximum Upgrade	0	0	-81	0	0	-81
2003	Existing Intertie	2002	2780	15715	364	74	20935
	DC Upgrade	0	0	-14	0	0	-14
	Third AC/COTP	0	0	-32	0	0	-32
	Maximum Upgrade	0	0	-47	0	0	-47

1/ "Other" resources include cogeneration, biomass, geothermal, wind, solar, and combined cycle.

Source: Marketing LP File (RPSE.P9800.DCW.IDUEIS.NOV87.SASOUT, 3-NOV-1987)

Table 4.1.16
EFFECTS OF FORMULA ALLOCATION OPTIONS ON INLAND SOUTHWEST GENERATION
Assuming Existing Capacity
(Annual Average MWs)

Existing Contracts		HYDRO	NUCLEAR	COAL	OIL/GAS	OTHER 1/	TOTAL
1988	Pre-IAP	1852	2780	9885	425	21	14963
	Proposed	0	0	-3	0	0	-3
	Hydro-First	0	0	31	0	0	31
1993	Pre-IAP	1997	2780	11304	420	62	16563
	Proposed	0	0	3	0	0	3
	Hydro-First	0	0	8	0	0	8
1998	Pre-IAP	2002	2780	13622	420	74	18898
	Proposed	0	0	7	0	0	7
	Hydro-First	0	0	6	0	0	6
2003	Pre-IAP	2002	2780	15730	364	74	20950
	Proposed	0	0	4	0	0	4
	Hydro-First	0	0	6	0	0	6
Federal Marketing							
1988	Pre-IAP	1852	2780	9844	425	21	14922
	Proposed	0	0	-9	0	0	-9
	Hydro-First	0	0	9	0	0	9
1993	Pre-IAP	1997	2780	11326	420	62	16585
	Proposed	0	0	-4	0	0	-4
	Hydro-First	0	0	4	0	0	4
1998	Pre-IAP	2002	2780	13615	420	74	18891
	Proposed	0	0	11	0	0	11
	Hydro-First	0	0	15	0	0	15
2003	Pre-IAP	2002	2780	15730	364	74	20950
	Proposed	0	0	0	0	0	0
	Hydro-First	0	0	-3	0	0	-3
Assured Delivery							
1988	Pre-IAP	1852	2780	9823	425	21	14901
	Proposed	0	0	-8	0	0	-8
	Hydro-First	0	0	-1	0	0	-1
1993	Pre-IAP	1997	2780	11336	420	62	16595
	Proposed	0	0	2	0	0	2
	Hydro-First	0	0	-2	0	0	-2
1998	Pre-IAP	2002	2780	13610	420	74	18886
	Proposed	0	0	-2	0	0	-2
	Hydro-First	0	0	1	0	0	1
2003	Pre-IAP	2002	2780	15710	364	74	20930
	Proposed	0	0	5	0	0	5
	Hydro-First	0	0	5	0	0	5

1/ "Other" resources include cogeneration, biomass, geothermal, wind, solar, and combined cycle.

Source: Marketing LP File (RPSE.P9800.DCW.IDUEIS.NOV87.SASOUT, 3-NOV-1987)

Table 4.1.17

EFFECTS OF FORMULA ALLOCATION OPTIONS ON INLAND SOUTHWEST GENERATION
Assuming Maximum Capacity
(Annual Average MWs)

Federal Marketing		HYDRO	NUCLEAR	COAL	OIL/GAS	OTHER 1/	TOTAL
1993	Pre-IAP	1997	2780	11193	420	62	16452
	Proposed	0	0	-8	0	0	-8
	Hydro-First	0	0	0	0	0	0
1998	Pre-IAP	2002	2780	13565	420	74	18841
	Proposed	0	0	-1	0	0	-1
	Hydro-First	0	0	-3	0	0	-3
2003	Pre-IAP	2002	2780	15678	364	74	20898
	Proposed	0	0	0	0	0	0
	Hydro-First	0	0	2	0	0	2
Assured Delivery							
1993	Pre-IAP	1997	2780	11166	420	62	16425
	Proposed	0	0	-9	0	0	-9
	Hydro-First	0	0	0	0	0	0
1998	Pre-IAP	2002	2780	13530	420	74	18806
	Proposed	0	0	-3	0	0	-3
	Hydro-First	0	0	1	0	0	1
2003	Pre-IAP	2002	2780	15667	364	74	20887
	Proposed	0	0	1	0	0	1
	Hydro-First	0	0	-2	0	0	-2

1/ "Other" resources include cogeneration, biomass, geothermal, wind, solar, and combined cycle.

Source: Marketing LP File (RPSE.P9800.DCW.IDUEIS.NOV87.SASOUT, 3-NOV-1987)

Table 4.1.18

EFFECTS OF LONG-TERM FIRM CONTRACTS AT ALTERNATIVE INTERTIE CAPACITIES
ON INLAND SOUTHWEST GENERATION
Assuming Proposed Formula Allocation
(Annual Average MWs)

Existing Intertie		HYDRO	NUCLEAR	COAL	OIL/GAS	OTHER 1/	TOTAL
1988	Existing Contracts	1852	2780	9882	425	21	14960
	Federal Marketing	0	0	-47	0	0	-47
	Assured Delivery	0	0	-67	0	0	-67
1993	Existing Contracts	1997	2780	11307	420	62	16566
	Federal Marketing	0	0	15	0	0	15
	Assured Delivery	0	0	31	0	0	31
1998	Existing Contracts	2002	2780	13629	420	74	18905
	Federal Marketing	0	0	-3	0	0	-3
	Assured Delivery	0	0	-21	0	0	-21
2003	Existing Contracts	2002	2780	15734	364	74	20954
	Federal Marketing	0	0	-4	0	0	-4
	Assured Delivery	0	0	-19	0	0	-19
DC Upgrade							
1993	Existing Contracts	1997	2780	11259	420	62	16518
	Federal Marketing	0	0	9	0	0	9
	Assured Delivery	0	0	-4	0	0	-4
1998	Existing Contracts	2002	2780	13627	420	74	18903
	Federal Marketing	0	0	2	0	0	2
	Assured Delivery	0	0	-26	0	0	-26
2003	Existing Contracts	2002	2780	15724	364	74	20944
	Federal Marketing	0	0	-3	0	0	-3
	Assured Delivery	0	0	-23	0	0	-23
Maximum Upgrade							
1993	Existing Contracts	1997	2780	11160	420	62	16419
	Federal Marketing	0	0	25	0	0	25
	Assured Delivery	0	0	-3	0	0	-3
1998	Existing Contracts	2002	2780	13547	420	74	18823
	Federal Marketing	0	0	17	0	0	17
	Assured Delivery	0	0	-20	0	0	-20
2003	Existing Contracts	2002	2780	15683	364	74	20903
	Federal Marketing	0	0	-5	0	0	-5
	Assured Delivery	0	0	-15	0	0	-15

1/ "Other" resources include cogeneration, biomass, geothermal, wind, solar, and combined cycle.

Source: Marketing LP File (RPSE.P9800.DCW.IDUEIS.NOV87.SASOUT, 3-NOV-1987)

Table 4.1.19

EFFECTS OF NEW NONFIRM RATE ON EXPORT SALES AND PACIFIC NORTHWEST GENERATION
(aMW)

	Change in Effect of Expanded Capacity 1/	Change in Effect of Proposed Formula Allocation 2/	Capacity/Allocation Effect 3/
1988			
Export Sales			
PNW	N/A	0	N/A
BC Hydro	N/A	0	N/A
Total		0	
PNW Generation			
Hydro	N/A	-1	N/A
Nuclear	N/A	0	N/A
Coal	N/A	2	N/A
CT	N/A	0	N/A
Other	N/A	0	N/A
TOTAL		1	
1993			
Export Sales			
PNW	-14	7	-7
BC Hydro	9	-7	-8
TOTAL	-5	0	-15
PNW Generation			
Hydro	9	5	13
Nuclear	0	0	0
Coal	-27	1	-25
CT	0	0	0
Other	2	-1	0
TOTAL	-16	5	-12
1998			
Export Sales			
PNW	1	0	1
BC Hydro	0	1	1
TOTAL	1	1	2
PNW Generation			
Hydro	-11	-1	-12
Nuclear	0	0	0
Coal	12	0	11
CT	0	0	0
Other	0	0	0
TOTAL	1	-1	-1
2003			
Export Sales			
PNW	2	1	4
BC Hydro	3	3	5
TOTAL	5	4	9
PNW Generation			
Hydro	-8	1	-8
Nuclear	0	0	0
Coal	10	0	10
CT	0	0	0
Other	0	0	0
TOTAL	2	1	2

1/ The indicated changes are the difference between the effect of Maximum Capacity with and without the new nonfirm rate.
2/ The indicated changes are the differences between the effect of the Proposed Formula Allocation option with and without the new nonfirm rate.
3/ The indicated changes are the difference between the effect of the Proposed Formula Allocation option at Maximum capacity with and without the new nonfirm rate.
Source: SAM Files (RESSALE.OUT), (RESTOT.OUT), and (BLUEBOOK.OUT); 7-Dec-1987

Table 4.1.20

EFFECTS OF PACIFIC SOUTHWEST HIGH GAS PRICES ON EXPORT SALES AND PACIFIC NORTHWEST GENERATION
(aMW)

	Change in Effect of Expanded Capacity	Change in Effect of Proposed Formula Allocation	Capacity/Allocation Effect
1988			
Export Sales			
PNW	N/A	16	N/A
BC Hydro	N/A	-59	N/A
Total		-43	
PNW Generation			
Hydro	N/A	3	N/A
Nuclear	N/A	0	N/A
Coal	N/A	14	N/A
CT	N/A	-1	N/A
Other	N/A	0	N/A
TOTAL		16	
1993			
Export Sales			
PNW	131	1	131
BC Hydro	-38	-8	-46
TOTAL	93	-7	85
PNW Generation			
Hydro	19	6	25
Nuclear	0	0	0
Coal	112	-7	105
CT	0	0	0
Other	-3	0	-4
TOTAL	128	-1	-126
1998			
Export Sales			
PNW	88	-20	68
BC Hydro	-31	20	-11
TOTAL	57	0	57
PNW Generation			
Hydro	-6	0	-7
Nuclear	0	0	0
Coal	88	-20	68
CT	1	0	1
Other	0	0	0
TOTAL	83	-20	62
2003			
Export Sales			
PNW	119	-9	110
BC Hydro	20	15	44
TOTAL	139	6	154
PNW Generation			
Hydro	0	0	-2
Nuclear	0	0	0
Coal	115	9	106
CT	2	0	2
Other	0	0	0
TOTAL	117	9	106

1/ The indicated changes are the difference between the effect of Maximum Capacity with and without Pacific Southwest high gas prices.
2/ The indicated changes are the differences between the effect of the Proposed Formula Allocation option with and without Pacific Southwest high gas prices.
3/ The indicated changes are the difference between the effect of the Proposed Formula Allocation option at Maximum capacity with and without Pacific Southwest high gas prices.
Source: SAM Files (RESSALE.OUT), (RESTOT.OUT), and (BLUEBOOK.OUT); 12-Dec-1987

Table 4.1.21

EFFECTS OF HIGH PACIFIC SOUTHWEST LOADS ON EXPORT SALES AND PACIFIC NORTHWEST GENERATION
(aMW)

	Change in Effect of Expanded Capacity	Change in Effect of Proposed Formula Allocation	Capacity/Allocation Effect
1988			
Export Sales			
PNW	N/A	3	N/A
BC Hydro	N/A	-17	N/A
Total		-14	
PNW Generation			
Hydro	N/A	2	N/A
Nuclear	N/A	0	N/A
Coal	N/A	-2	N/A
CT	N/A	0	N/A
Other	N/A	1	N/A
TOTAL		1	
1993			
Export Sales			
PNW	162	-13	149
BC Hydro	49	-4	45
TOTAL	211	-17	194
PNW Generation			
Hydro	6	0	6
Nuclear	0	0	0
Coal	161	-14	148
CT	0	0	0
Other	-1	0	-2
TOTAL	166	-14	152
1998			
Export Sales			
PNW	26	0	26
BC Hydro	10	1	11
TOTAL	36	1	37
PNW Generation			
Hydro	-2	1	-1
Nuclear	0	0	0
Coal	31	0	31
CT	1	0	1
Other	0	0	0
TOTAL	30	1	31
2003			
Export Sales			
PNW	17	-1	16
BC Hydro	53	2	55
TOTAL	70	-1	71
PNW Generation			
Hydro	0	1	-1
Nuclear	0	0	0
Coal	26	-1	25
CT	0	0	0
Other	0	0	0
TOTAL	26	0	24

1/ The indicated changes are the difference between the effect of Maximum Capacity with and without high Pacific Southwest loads.

2/ The indicated changes are the differences between the effect of the Proposed Formula Allocation option with and without high Pacific Southwest loads.

3/ The indicated changes are the difference between the effect of the Proposed Formula Allocation option at Maximum capacity with and without high Pacific Southwest loads.

Source: SAM Files (RESSALE.OUT), (RESTOT.OUT), and (BLUEBOOK.OUT); 12-Dec-1987

Table 4.1.22

EFFECTS OF LOW PACIFIC NORTHWEST LOADS ON EXPORT SALES AND PACIFIC NORTHWEST GENERATION
(aMW)

	Change in Effect of Expanded Capacity	Change in Effect of Proposed Formula Allocation	Capacity/Allocation Effect
1988			
Export Sales			
PNW	N/A	17	N/A
BC Hydro	N/A	-11	N/A
Total		6	
PNW Generation			
Hydro	N/A	2	N/A
Nuclear	N/A	0	N/A
Coal	N/A	13	N/A
CT	N/A	-1	N/A
Other	N/A	2	N/A
TOTAL		16	
1993			
Export Sales			
PNW	443	16	459
BC Hydro	45	-13	32
TOTAL	488	3	491
PNW Generation			
Hydro	375	3	378
Nuclear	0	0	0
Coal	81	8	90
CT	0	0	0
Other	-7	0	-8
TOTAL	449	11	460
1998			
Export Sales			
PNW	687	23	710
BC Hydro	-1	-22	-23
TOTAL	686	1	687
PNW Generation			
Hydro	709	5	714
Nuclear	0	0	0
Coal	-9	19	9
CT	0	0	0
Other	0	0	0
TOTAL	700	24	723
2003			
Export Sales			
PNW	812	17	829
BC Hydro	46	-18	29
TOTAL	858	-1	858
PNW Generation			
Hydro	739	7	746
Nuclear	0	0	0
Coal	63	10	72
CT	-1	0	-1
Other	0	0	0
TOTAL	801	17	817

1/ The indicated changes are the difference between the effect of Maximum Capacity with and without low Pacific Northwest loads.

2/ The indicated changes are the differences between the effect of the Proposed Formula Allocation option with and without low Pacific Northwest loads.

3/ The indicated changes are the difference between the effect of the Proposed Formula Allocation option at Maximum capacity with and without low Pacific Northwest loads.

Source: SAM Files (RESSALE.OUT), (RESTOT.OUT), and (BLUEBOOK.OUT); 12-Dec-1987

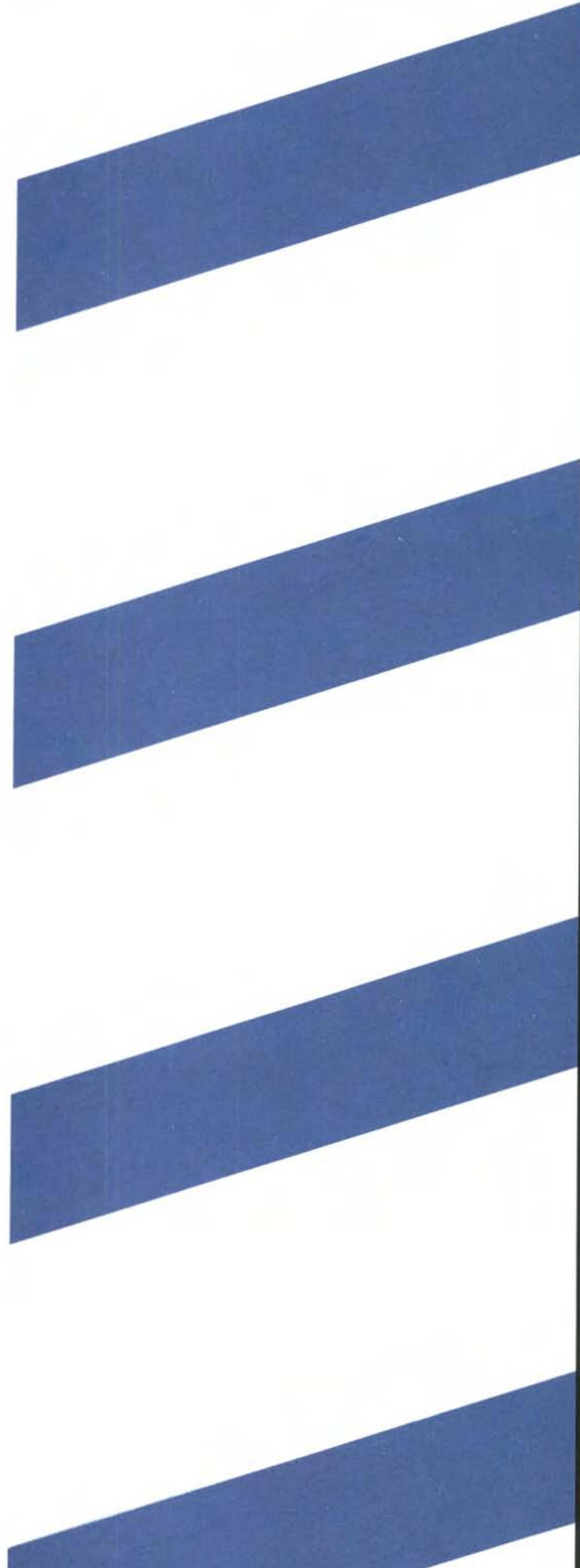
Table 4.1.23
EFFECTS OF ASSURED DELIVERY ALTERNATIVES 1, 2, AND 3 ON
PACIFIC NORTHWEST EXPORT SALES AND GENERATION 1/
(aMW)

	Alternative 1		Alternative 2	Alternative 3	
	Existing Capacity	DC Upgrade	Maximum Capacity	DC Upgrade	Maximum Capacity
1988					
Export Sales					
PNW Sales	129	N/A	N/A	N/A	N/A
BC Hydro Sales	-87	N/A	N/A	N/A	N/A
TOTAL	42	N/A	N/A	N/A	N/A
PNW Generation					
Hydro	-9	N/A	N/A	N/A	N/A
Nuclear	0	N/A	N/A	N/A	N/A
Coal	93	N/A	N/A	N/A	N/A
CT	-1	N/A	N/A	N/A	N/A
Other	0	N/A	N/A	N/A	N/A
TOTAL	83	N/A	N/A	N/A	N/A
1993					
Export Sales					
PNW Sales	175	154	205	158	163
BC Hydro Sales	-54	-53	-47	-56	-44
TOTAL	121	101	158	102	119
PNW Generation					
Hydro	-1	2	26	18	19
Nuclear	0	0	0	0	0
Coal	38	14	20	15	26
CT	5	5	3	4	4
Other	55	35	68	26	32
TOTAL	97	57	118	63	81
1998					
Export Sales					
PNW Sales	396	457	529	483	497
BC Hydro Sales	-31	-68	-29	-72	-18
TOTAL	362	389	500	411	479
PNW Generation					
Hydro	-114	-103	-67	-101	-67
Nuclear	807	807	807	807	807
Coal	-177	-130	-133	-111	-126
CT	-1	-2	-1	-2	-1
Other	0	-13	25	-16	-15
TOTAL	515	559	630	577	598
2003					
Export Sales					
PNW Sales	393	462	562	464	535
BC Hydro Sales	-24	-23	-6	-26	-3
TOTAL	369	439	556	438	532
PNW Generation					
Hydro	-120	-69	-23	-70	-22
Nuclear	818	818	818	818	818
Coal	-134	-113	-103	-114	-91
CT	-6	-7	-7	-7	-7
Other	-7	-26	10	-29	-29
TOTAL	551	602	695	598	669

1/ Assumes the Proposed Formula Allocation. This Table compares the alternative Assured Delivery sensitivity contract combinations with the Existing Contracts cases for the Intertie sizes indicated.

Source: SAM Files (RESSALE.OUT, 10-Feb-1988), (RESTOT.OUT, 10-Feb-1988), and (BLUEBOOK.OUT; 8-Feb-1988)

(VS6-WP-PG-6018K)



4.2 THE HYDROELECTRIC SYSTEM

OVERVIEW AND SUMMARY

The Columbia and Snake River systems are elements of substantial importance to the structure of the environment in the Pacific Northwest. They offer important opportunities for recreation. They also provide habitat for anadromous and resident fisheries. Numerous cultural resource sites exist in and around the major storage reservoirs that now form a part of these river systems. The first step in understanding the potential effects of Intertie decisions on these environmental resources is to understand the effects of such decisions on the operation of hydroelectric facilities and how, in turn, changes in hydroelectric system operation can alter the character and ecosystem of these environmental features.

The PNW hydro system is operated in accordance with constraints established by project owners and operators (Corps of Engineers [COE] and Bureau of Reclamation in the case of Federal projects) and in accordance with guidelines provided by the Pacific Northwest Coordination Agreement (PNCA). 1/ See Appendix C, Part 1 for a summary of hydrosystem planning and operation.

Federal hydro projects are operated to provide for multiple uses including flood control, power production, irrigation, navigation, recreation, fisheries, wildlife, and other uses. These sometimes competing interests are balanced by project owners and operators and are addressed through project operating constraints, FERC license conditions for non-Federal projects, annual planning criteria, or shorter-term constraints as needed. The COE will continue to operate their projects to provide for multiple uses regardless of BPA's Intertie decisions. The COE will not alter operations of its projects without first doing detailed impact assessments.

Within this context, Intertie decisions may affect how the hydro system is operated with resulting changes in reservoir elevations, flows, and spill. Hydro system parameters such as reservoir elevations, river flow, and spill can affect river uses for fish, recreation, and cultural resources. Therefore, an understanding of how Intertie decisions may affect these parameters is necessary before a specific assessment of environmental impacts can be made.

1/ The PNCA provides for an annual planning process which increases system reliability and optimizes the use of resources within constraints provided by the project owners. BPA and most of the region's public and private utilities operate under this agreement. This planning process, and the guidelines established by it, as well as operating constraints established by project owners, would not be changed as a result of Intertie decisions.

BPA's findings with respect to changes in river operations are discussed in Section 4.2.1. This section closes with a discussion of the results of sensitivity studies designed to expand the analyses to include a wider range of conditions. Discussion of how the predicted effects on river operations would be expected to affect recreation, irrigation and cultural resources is presented in Section 4.2.2. Section 4.2.3 covers anticipated effects on resident and anadromous fish. Tables immediately follow the text for each section.

4.2.1 RIVER OPERATIONS

Increasing Intertie capacity has little effect on reservoir elevations or refill probabilities. It does have the effect of converting about 100 to 150 aMW, and 200 to 250 aMW, of spill to generation under the DC Terminal expansion and Maximum capacity alternatives, respectively. The Pre-IAP and Proposed Formula Allocation alternatives differ little in their effect on reservoir elevations, refill probability, or overgeneration. The Hydro-First alternative results in slightly lower reservoir elevations and slightly less overgeneration than the other Formula Allocation alternatives. Firm marketing alternatives can have substantial effects on reservoir elevation although system refill is only slightly affected. Marketing actions result in some variation in overgeneration amounts, but changes from the Existing Contract condition are less than 10 percent.

4.2.1.1 Analytical Methods

While the analysis of power systems effects presented only annual data, the analysis of potential impacts of Intertie decisions on hydro system operations is based on monthly data from the SAM runs discussed at the beginning of this chapter. An analysis of monthly data was necessary to accommodate seasonal variations in the sensitivity of environmental factors (e.g., recreation, fishing) to river operations. The operational parameters analyzed include end-of-month reservoir elevation for the Federal storage reservoirs (Libby, Hungry Horse, Albeni Falls, Grand Coulee, and Dworshak); probability of system refill; and amount of overgeneration. Additional discussion on the subject of overgeneration spill is contained in Section 4.2.1.4 and in Section 4.2.3, which deals with effects on anadromous and resident fish. Because flow levels downstream of storage reservoirs and in the Columbia River are primarily a concern for resident and anadromous fish, discussion of flow levels is found in Section 4.2.3.

The System Analysis Model results necessarily reflect a great number of assumptions. In reality, there is more latitude in actual operations than is represented in the model. In addition, future conditions will probably differ from the assumptions to some degree. Thus, the model results are useful for comparative purposes, but must be interpreted within the framework of existing operating variability. A more detailed discussion of SAM and the assumptions used in these studies may be found in Appendix B, Part 1.

4.2.1.2 Reservoir Levels

The COE operates the entire Columbia River system to provide for flood control. Federal reservoirs provide storage for spring runoff thus affording flood control during the high runoff period and power benefits throughout the year. In addition, reservoirs provide important habitat for resident fish, afford numerous recreation opportunities and provide for irrigation in some areas. Some reservoirs are also rich in cultural resource sites. Changes in Intertie capacity, access, and marketing may influence reservoir levels and thus affect reservoir uses. Intertie decisions would not affect the ability of the COE to provide flood control protection.

The SAM was used to project end-of-month reservoir levels at five Federal storage reservoirs (Libby, Hungry Horse, Albeni Falls, Grand Coulee, and Dworshak) for all 20 capacity/policy/marketing combinations (cases) studied (Table 4.0.1). Results for 200 simulations were averaged to obtain mean end-of-month reservoir elevations for each study. Also, statistical comparisons were made to determine which alternatives were statistically different from selected 'base' cases. Selected comparisons are presented in Tables 4.2.1 through 4.2.6. (Tables may be found following page 4.2.1-8.) These comparisons typify effects observed on reservoir levels. Information on reservoir elevations for all cases is provided in Appendix C, Part 2.

Effects of Increasing Intertie Capacity

Table 4.2.1 presents expected differences in mean end-of-month reservoir levels for the DC Upgrade and Maximum capacity cases assuming the Proposed Formula Allocation and Existing Contracts. This table presents results for statistically different cases with a mean difference of 0.1 ft. or greater. Table 4.2.2 contains similar data for the DC, AC, and Maximum capacity cases assuming the Assured Delivery condition. Only minor changes in reservoir levels, generally less than one foot, are expected as a result of Intertie capacity increases. Most of the additional hydro energy generated for sale over expanded capacity is derived from conversion of spill to generation at downstream projects. Thus, reservoir operations are generally not affected.

An expanded Intertie would allow marketing of more energy in peak hours within the available generating capacity of the system. In some situations, economic benefits may be derived from delivering more energy during daytime hours and less energy during nighttime hours while not increasing total sales.

There is little additional flexibility available for peaking purposes at Libby, Hungry Horse, Albeni Falls, and Dworshak. Albeni Falls is operated by the COE at relatively constant outflow/generation levels. A review of generation records for 1986 and 1987 indicate that Hungry Horse and Dworshak were operated at minimum flow, maximum generation, or maximum peaking about 95 percent of the time. If a project is maintained at minimum discharge it is generally in order to enhance refill and therefore the project is not used for peaking purposes. Thus additional peaking at Hungry Horse and Dworshak could only occur about 5 percent of the time. At Libby, additional peaking would have been available approximately 15 percent of the time. At Libby much of this additional peaking was available on weekends when it normally would not be needed. Thus, there is little opportunity for increased peaking due to expanded Intertie capacity at Libby, Hungry Horse, Albeni Falls, and Dworshak. Intertie decisions would not be expected to cause significant increases in peaking at these projects.

This leaves Grand Coulee and downstream plants and the four lower Snake River plants to produce most of the additional peaking. Assuming 1,100 additional MW of peaking (the maximum increase resulting from the DC Upgrade) is produced by Grand Coulee and downstream projects (and the downstream projects are not also drafted) for 8 heavy load hours, the total additional elevation reduction at Grand Coulee would be less than 0.15 feet. Downstream flows would increase by less than 15 kcfs during the heavy load hours and decrease by about the same amount during the light load hours when generation is reduced. In actuality, the lower Snake River plants would also be used and, due to travel times between projects, several of the downstream projects would experience additional forebay fluctuations of 0.2 to 0.3 feet. These forebay fluctuations are small compared to normal daily fluctuations for these projects. The outflow fluctuations at downstream projects would be similar to those for Grand Coulee. The amount of energy which can be moved from nighttime hours into daytime hours is limited however by system requirements such as peaking capability and minimum flow constraints. These effects are independent of formula allocation or firm marketing assumptions.

Effects of Formula Allocation

Table 4.2.3 shows the effects of formula allocation alternatives on reservoir elevations at Existing Intertie size assuming the Existing Contracts condition. The Pre-IAP and Proposed Formula Allocations have similar effects on reservoir levels. Although the Proposed Formula Allocation method results in slightly higher reservoir levels in the two earliest years studied, differences between it and the Pre-IAP option are slight--typically less than 1 foot in all years studied. The Hydro-First alternative results in somewhat lower reservoir levels in the fall/winter of 1988. This effect is most pronounced at Hungry Horse where a difference of up to 3.5 feet or so could occur. This effect is limited to Hungry Horse for a few months in the first year studied. There is little difference between the Pre-IAP and Hydro-First alternatives in subsequent years.

Table 4.2.4 presents results for formula allocation alternatives at Maximum Intertie size assuming the Assured Delivery contracts condition. These results are similar to those for the Existing capacity, Existing Contracts comparisons. Differences in reservoir elevations between the Pre-IAP case and the two other alternatives are slight--typically being less than 1 foot. The Proposed Formula Allocation option generally results in slightly higher levels than the Pre-IAP option while the Hydro-First alternative produces slightly lower levels.

Short-term fluctuations of hydrosystem generation are related to shape and amount of load served as well as system operating constraints. Because formula allocation methods do not substantially affect the amount or shape of load served over the Intertie, the formula allocation options would not affect short-term fluctuations of reservoir levels or downstream flows.

Effects of Long-Term Firm Contracts

As can be seen in Tables 4.2.5 and 4.2.6, changes in long-term firm contracts have relatively substantial effects on reservoir elevations. Differences in reservoir levels between the Existing Contracts condition and the other firm contract alternatives are variable between months and years. The greatest differences in magnitude occur in the fall and winter months. Summer months show relatively minor effects with differences in reservoir elevations typically one foot or less. Results for the Federal Marketing and Assured Delivery alternatives are similar, although the Assured Delivery cases have somewhat higher reservoir levels in 1988 and 1993. Results are the same for all Intertie sizes and formula allocation alternatives.

Results for the firm contract cases are difficult to interpret due to the numerous variables they can affect. Firm contract assumptions can change the amount of firm surplus energy available, the shape of the firm load, as well as Intertie loading and California market conditions. Some of the contract assumptions change from year to year, thus leading to differences in results between years. Firm contract assumptions have a particular effect on reservoir operations because, as the amount of firm surplus and the shape of the firm load change, planned reservoir elevations are also changed. An example of this effect occurs in the early years when the Existing Contracts cases have more surplus firm energy than the alternative marketing cases. This means more surplus firm energy is available to be shifted and shaped into the fall period in the Existing Contracts cases. The result is that reservoir levels are generally lower for Existing Contracts than the other firm contract cases in 1988.

The only reservoir potentially affected by short-term changes due to Intertie decisions is Grand Coulee. The maximum contract level in these studies assumed 3,150 MW of capacity in the DC Upgrade and Maximum capacity cases for all formula allocation alternatives. This is an increase in capacity deliveries of 2,550 MW over the Existing Contracts alternative. Increased peaking deliveries of 2,550 MW for 10 hours/day would result in an elevation change at Grand Coulee of less than 0.5 feet and an increase in downstream flows of approximately 30 kcfs during peak hours. (See Appendix B, Part 4 for a discussion of the firm contract assumptions used in this study.)

4.2.1.3 System Refill

The amount of water stored in the hydro system at the end of each refill season (usually the end of July) represents water available for power production and nonpower uses during the remainder of the year. Hydrosystem operation after mid-January is based on the runoff forecast to enhance the probability of system refill while meeting firm loads. To the extent that Intertie decisions would adversely affect the ability of the hydrosystem to refill, reservoir uses such as recreation and resident fisheries may be affected.

System refill data for 20 years from the SAM studies were used to assess the potential for changes in reservoir refill. The system was considered to be full if, at the end of July, system content was 94 percent of the total possible system content. This check in SAM is based on whether the system on July 31 is less than 4,000 megawatt months below full. The total system contains approximately 65,000 megawatt months of storage, therefore the check on full or not full is based on the system being 4,000/65,000 = 6 percent below full. This 94 percent figure is essentially the same for both SAM and PNCA planning, and is used to determine the next years rule curves. It is sometimes confused with the 98 percent full number used prior to July 31 in PNCA planning for system refill and interchange accounting. Under the PNCA, if the system does not fill to 98 percent prior to July 31, then a check on July 31 is made to determine whether to use first or subsequent year rule curves. The PNCA criterion is that the system is considered to have refilled (for the purpose of FELCC adoption) whenever the system has attained a level on July 31 that is nearer the Storage Energy established for the first year of the Critical Period than for the second year. For 1987-1988, that point is 93 percent of the total system storage capability. The SAM model makes the July 31 check only to determine if the system is full.

Effects of Intertie Decisions

Reservoir refill varies over the 20-year study period from about 82 percent to about 90 percent. There are no apparent trends over time. Differences between years are probably due to a combination of variables including the randomly selected water conditions, loads, and thermal performance in each year as well as marketing conditions.

There is much less variability in system refill between study alternatives than there is between study years. The maximum difference among alternatives in any single year is about 1 to 2 percent. Over the 20-year period, mean refill probabilities differed between the 20 cases by less than 1 percent. Based on these results, Intertie decisions are not expected to have substantial effects on probability of system refill.

4.2.1.4 Overgeneration

The spring runoff usually provides more energy than can be used in the Pacific Northwest. As much as possible of this energy is stored or sold outside the region, and the remainder must be spilled. The amount of energy available varies depending on water conditions which are highly variable between years (see Appendix C, Part 1). This "excess" energy which could be generated, but must be spilled due to lack of available market, is called "overgeneration." The spill which results is called "overgeneration spill." Most of this spill occurs in May and June with smaller amounts in March, April, and July during wetter years. Less than 2 percent occurs during other months. This spill can help anadromous fish bypass turbines. At high levels however, the spill causes high levels of dissolved gases in the water which can adversely affect fish. This spill can be easily moved to wherever on the system it is most useful, or least harmful, as the case may be. (A more detailed discussion of the effects of spill on fish may be found in Section 4.2.3.) The majority of this spill normally occurs at night, but can be moved to other times of the day. This spill does not affect the total amount of water passing a project long-term, but may cause short-term (daily) variations in flow. The daily variations are normally adjusted to provide maximum benefit to fisheries.

The SAM model was used to project monthly amounts of overgeneration for 20 capacity/policy/marketing combinations (cases). Results for 200 simulations were averaged to obtain average monthly overgeneration amounts. Differences between the various cases were analyzed to determine the effects of each alternative.

Effects Of Increasing Intertie Capacity

Table 4.2.7 shows the effects of increasing Intertie capacity, assuming the Proposed Formula Allocation method and Existing Contracts. It shows 14-year averages (1993-2006) for the Existing capacity, DC Upgrade, and Maximum Intertie capacity cases as well as the differences from the Existing capacity overgeneration levels. Only 14 years were used because the Maximum capacity for the entire year is not available until 1993. The amount of overgeneration varies greatly between years but no patterns are discernable. The DC Terminal Expansion causes an overgeneration reduction of nearly 50 percent compared to Existing capacity. The Maximum capacity case reduces overgeneration by over 80 percent. Most of the remaining overgeneration occurs in June with lesser amounts in May and July.

Effects of Formula Allocation

The effects of formula allocation alternatives are minimal. Differences in overgeneration between the Pre-IAP and Proposed Formula Allocation cases are variable and less than 1 percent. The Hydro-First Allocation method reduces the annual average overgeneration spill by about 2 percent in the first half of the study and by somewhat greater amounts in the second half. These changes are small relative to the changes resulting from Intertie expansion alternatives and relative to the year-to-year variability which would normally be expected due to runoff conditions.

Effects of Long-Term Firm Contracts

The cases assuming Assured Delivery contracts result in increased overgeneration above Existing Contract levels of about 10 percent in the last half of the study. The effect is independent of Intertie size. The Federal Marketing cases show minimal changes from the Existing Contracts cases at Maximum capacity Upgrade. At Existing capacity, Federal Marketing produces both increases and decreases of 5 percent or less in overgeneration.

4.2.1.5 Sensitivity and Other Analyses

Several studies were conducted in order to determine the sensitivity of study results to assumptions used in modeling the environmental effects of Intertie decisions. A summary as well as detailed descriptions of sensitivity analyses conducted for both economic and environmental variables is given in Appendix B, Part 6. Typically, three studies were run for environmental analysis of each sensitivity case: the no-action base case (Pre-IAP, Existing capacity, Existing Contracts levels); the Proposed Formula Allocation at Existing capacity with Existing Contracts; and the Proposed Formula Allocation at the Maximum capacity with Existing Contracts. Those parameters thought to have potential for additional adverse environmental effects were chosen for analysis. They were increased California gas prices, increased California loads, decreased PNW loads, and the new nonfirm rate cap. Additional studies were also conducted on three firm contract alternatives (Assured Delivery Alternatives 1, 2, and 3). When sensitivity study results for hydrosystem parameters indicate a potential for additional adverse environmental effects, those effects are presented and evaluated in the appropriate sensitivity discussions throughout this EIS.

Studies were conducted using the SAM in the same manner described for the 20 original studies presented in Section 4.2.1.

California Gas Price. In order to analyze the potential effects of increased California gas prices, California market pricing was adjusted to reflect a high gas price forecast as opposed to the median price forecast used in the original studies. Sensitivity analyses increasing California gas prices do not affect relative changes in reservoir elevations under the Proposed Formula Allocation method or Maximum capacity.

California Loads. In order to evaluate the effects of higher than expected California loads, studies were run with California loads increased by 2,000 aMW. These study results are similar to the increased California gas price cases. Relative changes in reservoir levels are similar to the results of the original studies.

PNW Loads. Three sensitivity cases were run which used a low PNW load forecast (approximately 3000 aMW firm surplus throughout the 20-year study period). In this situation, there is additional surplus firm energy available to "move" into the fall period and reservoir target elevations are adjusted accordingly. Changes in reservoir elevations using the Proposed Formula Allocation method (as compared with the Pre-IAP method) are minimal. However, effects of increasing Intertie capacity are much greater when low PNW loads are assumed (Table 4.2.8a). Additional drafting of reservoirs occurs at Maximum Intertie capacity, especially in the late fall and early winter. No adverse impacts to recreation would be expected from this operation as reservoir levels during the summer months are similar between the Existing and Maximum capacity alternatives. Cultural resources and resident fish could be adversely affected by the lower reservoir elevations during the fall and winter (see Sections 4.2.2.4 and 4.2.3.3).

New Nonfirm Rate Cap. Since the initial SAM studies were conducted, the nonfirm rate cap has been adjusted. In order to verify that this change would not affect the environmental impacts of Intertie decisions, three sensitivity studies were run using the new nonfirm rate cap. The new results are consistent with the original studies in that neither the Proposed Formula Allocation method nor the Maximum capacity had major effects on reservoir operations.

Increased Power Sales and Power Exchanges. As previously described at the end of Section 4.1, three Assured Delivery contract configurations were analyzed in addition to the 400 MW Assured Delivery option. These configurations included increased levels of power sales and seasonal exchanges and reduced or eliminated capacity/energy exchanges. For a detailed description of the contracts included in these cases please see Appendix B, Parts 4 and 7.

The effects of additional sales and power exchanges were evaluated at Existing, DC Upgrade, and Maximum capacity levels. Alternative 1 effects were evaluated at Existing and DC Upgrade capacity levels, Alternative 2 effects were evaluated at Maximum capacity, and Alternative 3 effects were evaluated at DC Upgrade and Maximum capacity levels. The effects of additional firm sales and seasonal power exchanges are similar regardless of Intertie size. Like the other firm marketing alternatives, the Increased Power Sales and Exchanges cases have variable effects on reservoir operations. These additional contract alternatives result in generally lower reservoir levels in the fall as compared to the Existing Contracts alternative for all years studied. In 1988 and 1993 lower reservoir levels continue through the summer at Hungry Horse and Dworshak. In 1998 and 2003, Assured Delivery Alternatives 1 through 3 have generally higher reservoir elevations in the spring and summer months than the Existing Contracts alternative. This is in contrast to the Assured Delivery and Federal Marketing cases, which have higher reservoir elevations in the early years and somewhat lower elevations in the later years than the Existing Contract cases. Reservoir elevation data for these cases may be found in Tables 4.2.8b-d and in Appendix C, Part 2. Probability of system refill over 20 years is similar to the original cases studied being 85.4, 85.6, and 85.7 for Alternatives 1, 2, and 3, respectively. Because Assured Delivery Alternatives 1, 2, and 3 result in reservoir elevation changes, impacts to recreation, cultural resources, and resident fish could occur. These effects are discussed in Sections 4.2.2.4 and 4.2.3.3.

(VS6-PG-1814Z)

Table 4.2.1

EFFECTS OF INTERTIE CAPACITY ON RESERVOIR ELEVATIONS (Feet)

Assuming Proposed Formula Allocation and Existing Contracts

		1993			1998			2003		
			Elevation Differences			Elevation Differences			Elevation Differences	
Month	Project	Elevation Existing	DC	Max.	Elevation Existing	DC	Max.	Elevation Existing	DC	Max.
September	Albeni Falls	2060.8	-	-	2060.8	-	-	2061.0	-	-
	Dworshak	1568.5	-	-	1567.6	-	-	1571.8	-	-
	Grand Coulee	1288.0	-	-	1288.0	-	-	1288.3	-	-
	Hungry Horse	3533.0	-0.3	-	3530.8	-	-0.2	3537.5	-0.2	-0.4
	Libby	2451.8	-0.1	-	2451.3	-	-	2453.2	-	-
October	Albeni Falls	2057.2	-	-	2057.4	-	-	2057.6	-	-
	Dworshak	1565.1	-	-	1564.4	-0.1	-0.2	1568.2	-	-
	Grand Coulee	1288.0	-	-	1288.1	-	-	1288.3	-	-
	Hungry Horse	3524.3	-0.4	-	3523.2	-0.2	-0.3	3529.6	-0.5	-0.7
	Libby	2447.4	-	-	2447.6	-	-0.1	2449.5	-	-0.2
November	Albeni Falls	2052.6	-	-	2052.6	-	-	2052.6	-	-
	Dworshak	1553.4	-0.3	-	1554.0	-0.1	-0.2	1555.6	-	-0.2
	Grand Coulee	1288.2	-	0.1	1288.2	-	-	1288.4	-	-
	Hungry Horse	3523.7	-0.5	-	3523.0	-0.2	-0.3	3528.7	-0.3	-0.5
	Libby	2437.3	-	0.6	2438.3	-	-0.1	2439.5	-	-
December	Albeni Falls	2053.2	-	-	2053.3	-	-	2053.1	-	-
	Dworshak	1549.5	-0.2	-	1549.6	-	-0.1	1550.1	-	-
	Grand Coulee	1287.5	-	-	1287.6	-	-	1287.4	-	-
	Hungry Horse	3516.6	-0.5	-	3515.8	-	-0.3	3520.5	-0.4	-0.6
	Libby	2406.7	-	-	2407.0	-	-	2407.8	-	-
January	Albeni Falls	2054.8	0.1	0.2	2055.3	0.2	-	2055.0	-	-
	Dworshak	1527.1	-0.2	-	1528.2	-	-0.1	1527.0	-	-
	Grand Coulee	1277.7	0.5	0.6	1278.7	0.9	-	1278.5	-	-0.1
	Hungry Horse	3504.5	-0.4	-	3504.3	0.7	-0.3	3506.8	-0.4	-0.6
	Libby	2371.2	-	-	2368.0	-	-	2371.6	-	-
February	Albeni Falls	2055.1	-	-	2055.8	0.2	-	2055.4	-	-
	Dworshak	1505.0	-	-	1506.4	-	-0.1	1504.0	-	-
	Grand Coulee	1260.9	0.4	0.5	1262.9	1.0	-	1262.1	0.2	-0.2
	Hungry Horse	3490.9	-0.5	-	3490.8	0.3	-0.3	3491.9	-0.2	-0.3
	Libby	2342.8	-	-	2336.5	-	-0.1	2341.5	-	-
March	Albeni Falls	2055.6	-	-	2055.6	-	-	2055.6	-	-
	Dworshak	1477.7	-	-	1479.5	-	-	1476.1	-	-
	Grand Coulee	1236.2	0.4	0.5	1237.7	0.4	-0.3	1236.9	-0.6	-0.6
	Hungry Horse	3477.4	-	-	3477.1	-	-0.4	3478.3	-0.5	-0.6
	Libby	2335.0	-	-	2328.0	-0.1	-0.1	2334.2	-	-

Table 4.2.1 (Continued)

Month	Project	1993 Elevation Existing	1993 Elevation Differences DC	1993 Elevation Differences Max.	1998 Elevation Existing	1998 Elevation Differences DC	1998 Elevation Differences Max.	2003 Elevation Existing	2003 Elevation Differences DC	2003 Elevation Differences Max.
April 1-15	Albeni Falls	2055.4	-	-	2055.5	-	-	2055.5	-	-
	Dworshak	1487.1	-	-	1490.5	-	-	1485.7	-	-
	Grand Coulee	1233.9	-	-	1234.5	-	-0.7	1234.4	-0.8	-1.1
	Hungry Horse	3478.6	-	-	3478.8	-	-0.4	3480.6	-0.4	-0.5
	Libby	2336.4	-	-	2330.3	-0.1	-0.1	2336.4	-	-
April 16-30	Albeni Falls	2055.1	-	-	2055.6	-	-	2055.4	-	-0.1
	Dworshak	1505.5	-	-	1509.5	-	-	1503.9	-	-
	Grand Coulee	1231.4	-	-	1230.8	-	-	1231.3	-	-
	Hungry Horse	3484.7	-	-	3484.0	-	-0.4	3486.3	-0.4	-0.5
	Libby	2344.6	-	-	2339.5	-0.1	-0.1	2344.7	-	-
May	Albeni Falls	2062.4	-	-	2062.5	-	-	2062.4	-	-
	Dworshak	1559.6	-	-	1559.8	-	-	1557.5	-	-
	Grand Coulee	1251.9	0.3	0.4	1252.4	-	-	1251.1	-0.2	-0.2
	Hungry Horse	3520.3	-	-	3520.6	-	0.2	3519.7	-	-0.2
	Libby	2397.0	-	-	2396.0	-	-	2395.1	-	-
June	Albeni Falls	2062.7	-	-	2062.6	-	-	2062.6	-	-
	Dworshak	1589.6	-	-	1588.7	-	-	1588.8	-	-
	Grand Coulee	1286.5	-	-	1286.3	-	-	1285.5	-	-
	Hungry Horse	3546.4	-	-	3546.5	-	-0.1	3546.6	-	-
	Libby	2444.0	-	-	2444.6	-	-	2444.1	-	-
July	Albeni Falls	2062.5	-	-	2062.5	-	-	2062.5	-	-
	Dworshak	1590.2	-	-	1588.6	-	-	1589.3	-	-
	Grand Coulee	1290.0	-	-	1289.9	-	-	1290.0	-	-
	Hungry Horse	3547.0	-	-	3546.2	-	-0.1	3547.0	-	-
	Libby	2453.7	-	-	2453.7	-	-	2453.6	-	-
August 1-15	Albeni Falls	2062.5	-	-	2062.5	-	-	2062.5	-	-
	Dworshak	1587.9	-	-	1586.6	-	-	1587.1	-	-
	Grand Coulee	1290.0	-	-	1289.9	-	-	1290.0	-	-
	Hungry Horse	3544.8	-	-	3543.8	-	-0.2	3543.9	-	-
	Libby	2453.4	-	-	2453.1	-	-	2452.8	-	-
August 16-31	Albeni Falls	2062.5	-	-	2062.5	-	-	2062.5	-	-
	Dworshak	1585.4	-0.1	-	1584.5	-0.1	-0.1	1584.6	-	-
	Grand Coulee	1290.0	-	-	1289.9	-	-	1290.0	-	-
	Hungry Horse	3542.6	-	-	3541.6	-	-0.2	3541.0	-	-
	Libby	2453.3	-	-	2453.0	-	-	2452.6	-	-

Existing = Existing Intertie Capacity
DC = DC Intertie Upgrade
Max. = Maximum Capacity
- Indicates a difference which is not statistically significant or is less than 0.1 ft.
- A negative number indicates a lower elevation than the base condition.

(VS6-PG-1315I)

Table 4.2.2

EFFECTS OF INTERTIE CAPACITY ON RESERVOIR ELEVATIONS (FEET)

Assuming Proposed Formula Allocation and Assured Delivery

		1993				1998				2003			
		Elevation	Elevation Differences			Elevation	Elevation Differences			Elevation	Elevation Differences		
Month	Project	Existing	DC	AC	Max.	Existing	DC	AC	Max.	Existing	DC	AC	Max.
September	Albeni Falls	2060.7	–	–	–	2060.8	–	–	–	2060.9	–	–	–
	Dworshak	1567.1	–	–	–	1565.3	–	–	–	1570.4	-0.2	-0.2	-0.2
	Grand Coulee	1288.0	–	–	–	1288.0	–	–	–	1288.2	–	–	–
	Hungry Horse	3530.7	–	–	–	3527.3	–	-0.2	-0.4	3535.3	-0.3	-0.3	-0.5
	Libby	2451.1	–	–	–	2450.1	–	–	-0.1	2452.6	–	–	-0.1
October	Albeni Falls	2057.3	–	–	–	2057.4	–	–	–	2057.5	–	–	–
	Dworshak	1563.7	–	–	–	1561.8	–	-0.1	-0.2	1566.7	-0.3	-0.3	-0.3
	Grand Coulee	1288.1	–	–	–	1288.0	–	–	–	1288.2	–	–	–
	Hungry Horse	3522.1	–	–	–	3519.1	–	-0.3	-0.3	3526.8	-0.5	-0.6	-0.7
	Libby	2446.5	–	–	–	2445.5	–	-0.1	-0.2	2448.1	-0.3	-0.3	-0.3
November	Albeni Falls	2052.6	–	–	–	2052.6	–	–	–	2052.6	–	–	–
	Dworshak	1552.9	–	0.2	0.3	1552.4	–	-0.1	-0.2	1554.7	-0.2	-0.3	-0.3
	Grand Coulee	1288.3	–	–	–	1288.2	–	–	–	1288.4	–	–	–
	Hungry Horse	3521.7	–	–	–	3519.0	–	-0.3	-0.4	3525.8	-0.4	-0.4	-0.7
	Libby	2438.4	0.2	0.2	0.2	2437.3	–	-0.1	-0.2	2439.0	-0.1	-0.2	-0.3
December	Albeni Falls	2053.3	–	–	–	2053.3	–	–	–	2053.2	–	–	–
	Dworshak	1549.8	–	–	–	1548.7	–	–	–	1549.9	-0.1	-0.1	-0.2
	Grand Coulee	1287.6	–	–	–	1287.6	–	–	–	1287.5	–	–	–
	Hungry Horse	3516.5	–	–	–	3512.5	–	–	–	3518.5	-0.6	-0.7	-1.0
	Libby	2407.9	–	–	–	2406.7	–	–	-0.1	2407.8	-0.1	-0.1	-0.2
January	Albeni Falls	2055.0	–	0.1	0.1	2055.3	–	0.1	0.2	2055.0	–	–	–
	Dworshak	1528.0	–	–	–	1527.7	–	-0.1	-0.2	1527.0	–	–	–
	Grand Coulee	1278.3	–	0.4	0.4	1278.6	–	0.4	0.7	1278.7	–	-0.1	-0.1
	Hungry Horse	3505.2	–	–	–	3502.2	–	–	0.4	3505.8	-0.4	-0.5	-0.7
	Libby	2372.7	–	–	0.1	2367.8	–	–	–	2371.6	–	-0.4	-0.3
February	Albeni Falls	2055.2	–	–	–	2055.7	–	–	0.1	2055.4	–	–	–
	Dworshak	1506.2	–	–	–	1506.3	–	-0.1	-0.2	1504.1	–	–	–
	Grand Coulee	1261.4	–	0.4	0.4	1262.7	–	0.6	0.7	1262.3	-0.3	-0.3	-0.3
	Hungry Horse	3491.9	–	–	–	3489.5	–	–	–	3491.4	-0.3	-0.4	-0.6
	Libby	2344.3	–	–	–	2336.4	–	–	–	2341.8	–	-0.1	–
March	Albeni Falls	2055.6	–	–	–	2055.6	–	–	–	2055.6	–	–	–
	Dworshak	1478.5	–	–	–	1479.6	–	-0.1	-0.2	1476.2	–	–	–
	Grand Coulee	1237.2	–	0.3	–	1237.5	–	0.5	0.5	1237.6	-0.8	-0.9	-0.9
	Hungry Horse	3478.8	–	–	–	3476.0	–	–	–	3478.3	-0.8	-1.0	-1.2
	Libby	2336.6	–	–	–	2328.0	–	–	–	2334.4	–	-0.2	–

Table 4.2.2 (Continued)

Month	Project	1993 Elevation Existing	1993 Elevation Differences DC	1993 AC	1993 Max.	1998 Elevation Existing	1998 Elevation Differences DC	1998 AC	1998 Max.	2003 Elevation Existing	2003 Elevation Differences DC	2003 AC	2003 Max.
April 1-15	Albeni Falls	2055.4	-	-	-	2055.5	-	-	-	2055.5	-	-	-
	Dworshak	1487.7	-	-	-	1490.6	-	-0.1	-0.1	1485.8	-	-	-
	Grand Coulee	1234.8	-0.3	-	-	1234.2	-0.2	-	0.3	1235.2	-1.0	-1.2	-1.4
	Hungry Horse	3479.8	-	-	-	3478.6	-	-	-	3480.6	-0.7	-0.9	-1.1
	Libby	2338.0	-	-	-	2330.3	-	-	-	2336.8	-	-	-
April 16-30	Albeni Falls	2055.1	-	-	-	2055.6	-	-	-	2055.4	-	-	-0.1
	Dworshak	1505.9	-	-	-	1509.5	-	-0.1	-0.1	1503.8	-	-	-
	Grand Coulee	1232.0	-	-	-	1231.0	-	-	-	1231.6	-	-	-
	Hungry Horse	3485.9	-	-	-	3484.0	-	-	-	3486.3	-0.6	-0.8	-1.0
	Libby	2346.2	-	-	-	2339.5	-	-	-	2345.0	-	-	-
May	Albeni Falls	2062.4	-	-	-	2062.5	-	-	-	2062.4	-	-	-
	Dworshak	1560.0	-	-	-	1559.8	-	-0.1	-0.1	1557.5	-	-	-
	Grand Coulee	1252.6	0.3	0.3	0.2	1252.5	-	-	-	1251.4	-0.2	-0.2	-0.2
	Hungry Horse	3521.2	-	-	-	3520.7	-0.1	-0.3	-0.4	3519.5	-0.2	-0.3	-0.4
	Libby	2397.9	-	-	-	2396.1	-	-	-	2395.3	-	-0.2	-
June	Albeni Falls	2062.7	-	-	-	2062.6	-	-	-	2062.6	-	-	-
	Dworshak	1590.0	-	-	-	1588.9	-	-	-	1588.9	-	-	-
	Grand Coulee	1286.6	-	-	-	1286.3	-	-	-	1285.6	-	-	-
	Hungry Horse	3547.1	-	-	-	3546.7	-	-0.2	-0.2	3546.6	-	-0.2	-0.2
	Libby	2444.5	-	-	-	2444.6	-	-	-	2444.2	-	-	-
July	Albeni Falls	2062.5	-	-	-	2062.5	-	-	-	2062.5	-	-	-
	Dworshak	1590.2	-	-	-	1588.5	-	-	-	1589.3	-	-	-
	Grand Coulee	1290.0	-	-	-	1289.9	-	-	-	1290.0	-	-	-
	Hungry Horse	3547.7	-	-	-0.2	3546.4	-	-0.2	-0.2	3547.0	-	-0.1	-
	Libby	2454.2	-	-	-	2453.7	-	-	-	2453.6	-	-	-
August 1-15	Albeni Falls	2062.5	-	-	-	2062.5	-	-	-	2062.5	-	-	-
	Dworshak	1587.7	-	-	-	1586.3	-	-0.1	-0.1	1586.8	-	-	-
	Grand Coulee	1290.0	-	-	-	1289.9	-	-	-	1289.9	-	-	-
	Hungry Horse	3545.0	-	-	-0.2	3543.7	-	-0.2	-0.3	3543.7	-0.1	-0.2	-
	Libby	2453.7	-	-	-	2452.9	-	-	-	2452.6	-	-	-
August 16-31	Albeni Falls	2062.5	-	-	-	2062.5	-	-	-	2062.5	-	-	-
	Dworshak	1585.0	-	-	-0.1	1584.0	-	-0.1	-0.2	1584.1	-0.1	-0.1	-
	Grand Coulee	1290.0	-	-	-	1289.9	-	-	-	1290.0	-	-	-
	Hungry Horse	3542.1	-	-	-	3540.9	-	-0.2	-0.3	3540.2	-0.2	-0.2	-0.2
	Libby	2453.6	-	-	-	2452.8	-	-	-0.1	2452.3	-	-	-

Existing = Existing Intertie Capacity
DC = DC Intertie Upgrade
AC = 3rd A.C. Intertie
Max. = Maximum Capacity
- Indicates a difference which is not statistically significant or is less than 0.1 ft.
- A negative number indicates a lower elevation than the base condition.

(VS6-PG-1315I)

Table 4.2.3

EFFECTS OF FORMULA ALLOCATION ON RESERVOIR ELEVATIONS (FEET)

Assuming Existing Capacity and Existing Contracts

		1988			1993			1998			2003		
		Elevation	Elevation Differences		Elevation	Elevation Differences		Elevation	Elevation Differences		Elevation	Elevation Differences	
Month	Project	Pre-IAP	PR	HF	Pre-IAP	PR	HF	Pre-IAP	PR	HF	Pre-IAP	PR	HF
September	Albeni Falls	2060.8	0.1	-0.1	2060.7	–	–	2060.8	–	–	2061.1	–	–
	Dworshak	1575.1	0.7	-0.9	1568.6	–	–	1567.7	-0.1	-0.1	1572.1	-0.3	-0.3
	Grand Coulee	1288.1	0.1	-0.1	1288.0	–	–	1288.0	–	–	1288.4	–	–
	Hungry Horse	3545.2	0.9	-1.6	3533.1	–	–	3530.9	-0.1	-0.2	3537.7	-0.2	-0.3
	Libby	2455.1	0.3	-0.4	2451.8	–	-0.2	2451.3	–	–	2453.3	–	–
October	Albeni Falls	2057.4	–	-0.3	2057.2	–	–	2057.4	–	–	2057.6	–	-0.1
	Dworshak	1571.4	0.5	-1.6	1565.1	–	–	1564.5	–	-0.2	1568.3	-0.1	-0.3
	Grand Coulee	1288.2	–	-0.2	1288.0	–	–	1288.1	–	–	1288.3	–	–
	Hungry Horse	3536.7	0.4	-3.6	3524.4	–	–	3523.3	-0.1	-0.3	3529.8	-0.2	-0.5
	Libby	2448.2	–	-2.1	2447.4	–	-0.1	2447.6	–	-0.1	2449.6	-0.1	-0.2
November	Albeni Falls	2052.6	–	–	2052.6	–	–	2052.6	–	–	2052.6	–	–
	Dworshak	1556.9	0.5	-1.7	1553.4	–	–	1554.0	–	-0.1	1555.7	-0.1	-0.3
	Grand Coulee	1288.1	–	–	1288.2	–	–	1288.2	–	–	1288.4	–	–
	Hungry Horse	3535.4	0.7	-3.4	3523.7	–	–	3523.0	–	–	3528.7	–	-0.2
	Libby	2435.0	1.0	-1.0	2437.3	–	–	2438.3	–	–	2439.6	–	–
December	Albeni Falls	2052.8	–	–	2053.1	0.2	–	2053.3	–	–	2053.1	–	–
	Dworshak	1546.2	–	-1.8	1549.3	0.3	-0.3	1549.7	–	–	1550.2	-0.1	-0.2
	Grand Coulee	1287.2	–	–	1287.4	0.2	–	1287.6	–	–	1287.5	–	–
	Hungry Horse	3524.5	0.6	-2.8	3515.6	1.0	-0.7	3515.8	–	–	3520.6	–	-0.3
	Libby	2400.7	0.3	-1.2	2406.6	–	-0.2	2407.0	–	–	2407.8	–	–
January	Albeni Falls	2054.2	–	–	2054.7	0.1	–	2055.3	–	–	2055.0	–	–
	Dworshak	1526.0	–	-0.5	1527.0	–	-0.2	1528.2	–	–	1527.1	–	–
	Grand Coulee	1275.1	0.1	-0.4	1277.4	0.4	-0.2	1278.7	–	–	1278.5	–	–
	Hungry Horse	3508.5	0.3	-2.1	3503.9	0.7	-0.7	3504.3	–	–	3506.9	–	-0.3
	Libby	2365.8	–	-1.2	2371.0	0.1	-0.3	2368.0	–	–	2371.6	–	–
February	Albeni Falls	2054.8	–	–	2055.0	–	–	2055.8	–	–	2055.4	–	–
	Dworshak	1504.2	–	-0.4	1504.9	–	-0.1	1506.4	–	–	1504.0	–	–
	Grand Coulee	1257.9	0.3	-0.4	1260.4	0.5	–	1262.9	–	–	1262.2	–	-0.2
	Hungry Horse	3496.7	0.2	-1.5	3490.6	0.3	-0.4	3490.8	–	–	3492.0	–	-0.2
	Libby	2340.0	–	–	2342.8	–	–	2336.5	–	–	2341.5	–	–
March	Albeni Falls	2055.6	–	–	2055.6	–	–	2055.6	–	–	2055.6	–	–
	Dworshak	1477.3	–	–	1477.7	–	-0.1	1479.5	–	–	1476.1	–	–
	Grand Coulee	1235.5	0.4	-0.4	1235.8	0.5	–	1237.7	–	-0.3	1237.1	-0.2	-0.8
	Hungry Horse	3484.9	0.3	-1.3	3477.1	0.3	–	3477.1	–	-0.1	3478.4	–	-0.4
	Libby	2333.5	–	–	2335.0	–	–	2328.0	–	–	2334.2	–	–

Table 4.2.3 (Continued)

Month	Project	1988 Elevation Pre-IAP	1988 Elevation Differences PR	1988 Elevation Differences HF	1993 Elevation Pre-IAP	1993 Elevation Differences PR	1993 Elevation Differences HF	1998 Elevation Pre-IAP	1998 Elevation Differences PR	1998 Elevation Differences HF	2003 Elevation Pre-IAP	2003 Elevation Differences PR	2003 Elevation Differences HF
April 1-15	Albeni Falls	2055.5	–	–	2055.4	–	–	2055.5	–	–	2055.5	–	–
	Dworshak	1487.6	–	–	1487.1	–	-0.1	1490.5	–	–	1485.7	–	–
	Grand Coulee	1233.7	0.9	-0.6	1233.7	0.2	-0.4	1234.5	–	-0.7	1234.6	-0.2	-1.1
	Hungry Horse	3486.4	0.3	-1.1	3478.3	0.3	–	3478.8	–	-0.1	3480.6	–	-0.4
	Libby	2335.7	–	–	2336.4	–	–	2330.3	–	–	2336.4	–	–
April 16-30	Albeni Falls	2055.3	0.1	–	2055.1	–	–	2055.6	–	–	2055.4	–	–
	Dworshak	1506.1	–	–	1505.5	–	–	1509.5	–	–	1503.9	–	–
	Grand Coulee	1231.7	0.4	–	1231.5	–	–	1230.8	–	–	1231.3	–	–
	Hungry Horse	3492.5	0.7	-1.2	3484.3	0.4	-0.3	3484.0	–	-0.1	3486.4	-0.1	-0.4
	Libby	2344.5	0.2	–	2344.7	–	–	2339.5	–	–	2344.7	–	–
May	Albeni Falls	2062.5	–	–	2062.4	–	–	2062.5	–	–	2062.4	–	–
	Dworshak	1560.1	–	–	1559.6	–	–	1559.8	–	–	1557.5	–	–
	Grand Coulee	1253.9	0.4	–	1251.8	–	–	1252.4	–	–	1251.1	–	-0.2
	Hungry Horse	3525.0	0.6	-0.7	3520.1	0.2	-0.3	3520.6	–	–	3519.8	–	-0.2
	Libby	2397.2	0.2	–	2397.0	–	–	2396.0	–	–	2395.1	–	–
June	Albeni Falls	2062.6	–	–	2062.7	–	–	2062.6	–	–	2062.6	–	–
	Dworshak	1591.3	–	–	1589.6	–	–	1588.7	–	–	1588.8	–	–
	Grand Coulee	1286.8	0.1	–	1286.5	–	–	1286.3	–	–	1285.5	–	–
	Hungry Horse	3551.6	0.4	-0.5	3546.3	–	-0.2	3546.5	–	–	3546.6	–	–
	Libby	2445.7	0.2	–	2443.9	–	–	2444.6	–	–	2444.2	–	–
July	Albeni Falls	2062.5	–	–	2062.5	–	–	2062.5	–	–	2062.5	–	–
	Dworshak	1593.4	–	–	1590.3	–	–	1588.6	–	–	1589.4	–	–
	Grand Coulee	1290.0	–	–	1290.0	–	–	1289.9	–	–	1290.0	–	–
	Hungry Horse	3553.9	0.1	–	3547.0	–	–	3546.2	–	–	3547.0	–	–
	Libby	2455.4	–	–	2453.7	–	–	2453.7	–	–	2453.6	–	–
August 1-15	Albeni Falls	2062.5	–	–	2062.5	–	–	2062.5	–	–	2062.5	–	–
	Dworshak	1592.6	–	–	1588.1	–	–	1586.6	–	–	1587.1	–	–
	Grand Coulee	1290.0	–	–	1290.0	–	–	1289.9	–	–	1290.0	–	–
	Hungry Horse	3553.2	–	–	3544.9	–	–	3543.8	–	–	3543.9	–	–
	Libby	2455.5	–	–	2453.4	–	–	2453.1	–	–	2452.8	–	–
August 16-31	Albeni Falls	2062.5	–	–	2062.5	–	–	2062.5	–	–	2062.5	–	–
	Dworshak	1591.3	–	–	1585.4	–	–	1584.5	–	–	1584.6	–	–
	Grand Coulee	1290.0	–	–	1290.0	–	–	1289.9	–	–	1290.0	–	–
	Hungry Horse	3552.3	–	–	3542.6	–	–	3541.6	–	–	3541.0	–	–
	Libby	2455.5	–	–	2453.3	–	–	2453.0	–	–	2452.6	–	–

PR = Proposed Formula Allocation
HF = Hydro-First Formula Allocation
– Indicates a difference which is not statistically significant or is less than 0.1 ft.
– A negative number indicates a lower elevation than the base condition.

(VS6-PG-1315I)

Table 4.2.4

EFFECTS OF FORMULA ALLOCATION ON RESERVOIR ELEVATIONS (FEET)

Assuming Maximum Capacity and Assured Delivery

		1988			1993			1998			2003		
			Elevation Differences			Elevation Differences			Elevation Differences			Elevation Differences	
Month	Project	Elevation Pre-IAP	PR	HF	Elevation Pre-IAP	PR	HF	Elevation Pre-IAP	PR	HF	Elevation Pre-IAP	PR	HF
September	Albeni Falls	2061.0	-	-	2060.7	-	-	2060.8	-	-	2060.9	-	-
	Dworshak	1574.8	0.2	-0.2	1566.9	0.3	-0.3	1565.0	-	-	1570.2	-	-
	Grand Coulee	1288.3	-	-	1288.0	-	-	1288.0	-	-	1288.2	-	-
	Hungry Horse	3544.4	0.4	-0.5	3530.0	0.5	-0.5	3526.8	-	-	3534.9	-	-
	Libby	2455.2	-	-0.1	2450.9	0.1	-0.1	2449.9	-	-	2452.5	-	-
October	Albeni Falls	2057.4	-	-0.2	2057.3	-	-	2057.3	-	-	2057.4	-	-
	Dworshak	1571.0	0.2	-0.6	1563.5	0.2	-0.4	1561.6	-	-	1566.4	-	-
	Grand Coulee	1288.2	-	-0.1	1288.1	-	-	1288.0	-	-	1288.2	-	-
	Hungry Horse	3535.2	-	-1.2	3521.5	0.5	-0.6	3518.6	0.2	-	3526.1	-	-
	Libby	2450.4	-	-0.6	2446.4	-	-0.2	2445.3	-	-	2447.8	-	-
November	Albeni Falls	2052.6	-	-	2052.6	-	-	2052.6	-	-	2052.6	-	-
	Dworshak	1557.2	0.2	-0.7	1553.0	0.2	-0.3	1552.1	0.1	-	1554.4	-	-
	Grand Coulee	1288.1	-	-	1288.3	-	-	1288.2	-	-	1288.4	-	-
	Hungry Horse	3534.3	0.4	-1.1	3521.1	0.3	-0.6	3518.5	-	-	3525.2	-	-
	Libby	2439.6	0.4	-0.5	2438.4	0.2	-0.2	2437.1	-	-	2438.8	-	-
December	Albeni Falls	2052.8	0.1	-	2053.1	0.2	-	2053.3	-	-	2053.2	-	-
	Dworshak	1551.4	0.2	-0.3	1549.6	0.3	-0.2	1548.5	0.1	-	1549.7	-	-
	Grand Coulee	1287.2	-	-	1287.5	0.2	-	1287.5	-	-	1287.5	-	-
	Hungry Horse	3524.7	1.1	-0.9	3515.2	1.1	-0.8	3512.0	0.3	-	3517.6	-	-
	Libby	2407.5	0.1	-	2407.9	-	-0.2	2406.5	-	-	2407.6	-	-
January	Albeni Falls	2054.8	-	-	2054.8	0.3	-	2055.3	0.1	-	2055.0	-	-
	Dworshak	1530.1	0.3	-	1527.8	0.2	-0.1	1527.5	-	-	1526.8	-	-
	Grand Coulee	1277.3	0.2	-	1277.8	0.9	-0.3	1278.7	0.6	-0.2	1278.5	-	-
	Hungry Horse	3512.1	1.1	-0.4	3504.3	1.0	-0.5	3501.9	0.8	-0.1	3505.2	-0.1	-
	Libby	2372.3	0.3	-0.1	2372.5	0.4	-0.1	2367.8	-	-	2371.3	-	-
February	Albeni Falls	2055.2	-	-	2055.1	0.1	-	2055.7	0.1	-	2055.4	-	-
	Dworshak	1507.5	0.2	-0.1	1506.0	0.2	-	1506.1	-	-	1504.0	-	-
	Grand Coulee	1260.2	0.2	-0.2	1261.0	0.9	-0.2	1262.8	0.6	-0.3	1262.0	-	-
	Hungry Horse	3499.6	0.6	-0.5	3491.4	0.5	-0.2	3489.2	0.5	-0.1	3490.9	-	-
	Libby	2343.6	0.4	-	2344.1	0.2	-	2336.3	-	-	2341.7	-	-
March	Albeni Falls	2055.6	-	-	2055.6	-	-	2055.6	-	-	2055.6	-	-
	Dworshak	1478.7	-	-	1478.3	-	-	1479.5	-	-	1476.3	-	-
	Grand Coulee	1236.3	0.3	-0.5	1236.4	0.8	-	1237.5	0.5	-0.1	1236.8	-	-
	Hungry Horse	3486.4	0.5	-0.6	3478.0	0.6	-	3476.2	0.3	-0.1	3477.2	-	-
	Libby	2336.6	0.4	-	2336.5	0.1	-	2327.9	-	-	2334.4	-	-

Table 4.2.4 (Continued)

Month	Project	1988			1993			1998			2003		
		Elevation Pre-IAP	Elevation Differences PR	HF	Elevation Pre-IAP	Elevation Differences PR	HF	Elevation Pre-IAP	Elevation Differences PR	HF	Elevation Pre-IAP	Elevation Differences PR	HF
April 1-15	Albeni Falls	2055.5	-	-	2055.4	-	-	2055.5	-	-	2055.5	-	-
	Dworshak	1488.7	-	-	1487.6	-	-	1490.4	-	-	1486.0	-	-
	Grand Coulee	1234.6	0.5	-0.9	1234.0	0.8	-	1233.9	0.6	-	1233.7	-	-
	Hungry Horse	3488.0	0.5	-0.6	3479.2	0.4	-0.2	3478.1	0.3	-	3479.5	-	-
	Libby	2338.9	0.4	-	2337.9	0.1	-	2330.1	-	-	2336.7	-	-
April 16-30	Albeni Falls	2055.4	-	-	2055.0	0.1	-	2055.5	-	-	2055.2	-	-
	Dworshak	1507.1	-	-	1505.8	-	-	1509.3	-	-	1504.2	-	-
	Grand Coulee	1231.8	0.2	-0.2	1231.9	0.1	-	1231.0	-	-	1231.5	-	-
	Hungry Horse	3493.3	0.7	-0.6	3485.2	0.6	-	3483.5	0.3	-	3485.3	-	-
	Libby	2347.5	0.4	-	2346.0	0.1	-	2339.4	-	-	2344.9	-	-
May	Albeni Falls	2062.4	-	-	2062.4	-	-	2062.5	-	-	2062.4	-	-
	Dworshak	1561.1	-	-	1559.9	-	-	1559.6	-	-	1557.6	-	-
	Grand Coulee	1253.7	0.2	-	1252.6	0.2	-0.2	1252.5	-	-	1251.3	-	-
	Hungry Horse	3525.7	0.5	-0.3	3520.8	0.4	-	3520.3	-	-	3519.2	-	-
	Libby	2398.9	0.2	-	2397.8	-	-	2396.0	-	-	2395.2	-	-
June	Albeni Falls	2062.6	-	-	2062.7	-	-	2062.6	-	-	2062.6	-	-
	Dworshak	1592.1	-	-	1589.9	-	-	1588.8	-	-	1588.9	-	-
	Grand Coulee	1286.6	0.1	-	1286.6	-	-	1286.3	-	-	1285.6	-	-
	Hungry Horse	3551.9	0.5	-0.2	3546.7	-	-	3546.4	-	-	3546.3	-	-
	Libby	2446.5	0.2	-	2444.5	0.1	-	2444.5	-	-	2444.2	-	-
July	Albeni Falls	2062.5	-	-	2062.5	-	-	2062.5	-	-	2062.5	-	-
	Dworshak	1593.7	-	-	1590.2	-	-	1588.4	-	-	1589.3	-	-
	Grand Coulee	1290.0	-	-	1290.0	-	-	1289.9	-	-	1289.9	-	-
	Hungry Horse	3553.6	0.4	-	3547.4	-	-	3546.1	-	-	3546.9	-	-
	Libby	2456.1	0.2	-	2454.2	-	-	2453.6	-	-	2453.6	-	-
August 1-15	Albeni Falls	2062.5	-	-	2062.5	-	-	2062.5	-	-	2062.5	-	-
	Dworshak	1592.2	0.2	-	1587.6	-	-	1586.1	-	-	1586.7	-	-
	Grand Coulee	1290.0	-	-	1290.0	-	-	1289.9	-	-	1289.9	-	-
	Hungry Horse	3551.9	0.4	-	3544.8	-	-	3543.4	-	-	3543.6	-	-
	Libby	2456.0	0.2	-	2453.6	-	-	2452.8	-	-	2452.6	-	-
August 16-31	Albeni Falls	2062.5	-	-	2062.5	-	-	2062.5	-	-	2062.5	-	-
	Dworshak	1590.5	0.3	-	1584.8	-	-	1583.9	-	-	1583.9	-	-
	Grand Coulee	1290.0	-	-	1290.0	-	-	1289.9	-	-	1290.0	-	-
	Hungry Horse	3550.3	0.5	-	3541.8	-	-	3540.6	-	-	3540.0	-	-
	Libby	2455.9	0.2	-	2453.5	-	-	2452.7	-	-	2452.2	-	-

PR = Proposed Formula Allocation
HF = Hydro-First Formula Allocation
- Indicates a difference which is not statistically significant or is less than 0.1 ft.
- A negative number indicates a lower elevation than the base condition.

(VS6-PG-1315I)

Table 4.2.5

EFFECTS OF LONG-TERM FIRM CONTRACTS ON RESERVOIR ELEVATIONS (FEET)

Assuming Proposed Formula Allocation and Existing Capacity

		1988			1993			1998			2003		
		Elevation	Differences		Elevation	Differences		Elevation	Differences		Elevation	Differences	
Month	Project	Existing	FM	AD	Existing	FM	AD	Existing	FM	AD	Existing	FM	AD
September	Albeni Falls	2060.9	–	–	2060.8	–	–	2060.8	–	–	2061.0	-0.2	–
	Dworshak	1575.8	-1.2	-0.7	1568.5	-2.5	-1.5	1567.6	-1.9	-2.3	1571.8	-1.8	-1.4
	Grand Coulee	1288.3	–	–	1288.0	–	–	1288.0	–	–	1288.3	-0.2	-0.1
	Hungry Horse	3546.1	-2.1	-1.3	3533.0	-4.0	-2.3	3530.8	-2.9	-3.5	3537.5	-2.6	-2.1
	Libby	2455.3	-0.4	–	2451.8	-1.4	-0.8	2451.3	-1.0	-1.2	2453.2	-0.8	-0.6
October	Albeni Falls	2057.4	–	–	2057.2	–	–	2057.4	-0.1	–	2057.6	-0.2	–
	Dworshak	1571.9	-1.0	-0.7	1565.1	-2.8	-1.4	1564.4	-2.2	-2.6	1568.2	-2.0	-1.5
	Grand Coulee	1288.2	–	–	1288.0	–	–	1288.1	–	–	1288.3	-0.1	–
	Hungry Horse	3537.0	-2.0	-1.6	3524.3	-4.8	-2.2	3523.2	-3.7	-4.1	3529.6	-3.9	-2.8
	Libby	2448.1	1.1	2.4	2447.4	-2.3	-0.9	2447.6	-2.2	-2.1	2449.5	-1.9	-1.4
November	Albeni Falls	2052.6	–	–	2052.6	–	–	2052.6	–	–	2052.6	–	–
	Dworshak	1557.5	–	–	1553.4	-1.5	-0.4	1554.0	-1.4	-1.6	1555.6	-1.4	-0.9
	Grand Coulee	1288.2	–	–	1288.2	-0.1	0.1	1288.2	–	–	1288.4	-0.1	–
	Hungry Horse	3536.1	-1.9	-1.4	3523.7	-4.8	-2.0	3523.0	-3.5	-4.0	3528.7	-3.9	-2.8
	Libby	2435.9	2.4	4.1	2437.3	-0.8	1.1	2438.3	-1.1	-1.0	2439.5	-1.0	-0.5
December	Albeni Falls	2052.8	–	0.1	2053.2	–	0.1	2053.3	-0.1	–	2053.1	–	–
	Dworshak	1546.3	3.8	5.2	1549.5	-0.7	–	1549.6	-1.0	-0.9	1550.1	-0.6	-0.2
	Grand Coulee	1287.2	–	–	1287.5	–	–	1287.6	-0.1	–	1287.4	–	–
	Hungry Horse	3525.2	–	–	3516.6	-3.6	–	3515.8	-3.7	-3.3	3520.5	-3.8	-2.0
	Libby	2400.9	4.0	6.7	2406.7	–	1.2	2407.0	-0.7	-0.3	2407.8	-0.4	–
January	Albeni Falls	2054.2	0.4	0.7	2054.8	–	0.1	2055.3	-0.1	–	2055.0	–	–
	Dworshak	1526.2	3.0	4.3	1527.1	–	0.9	1528.2	-0.5	-0.4	1527.0	-0.2	–
	Grand Coulee	1275.3	1.4	2.2	1277.7	–	0.6	1278.7	-0.4	-0.1	1278.5	-0.3	0.1
	Hungry Horse	3508.8	2.0	4.4	3504.5	-2.0	–	3504.3	-2.4	-2.0	3506.8	-2.4	-1.0
	Libby	2365.8	4.2	6.8	2371.2	–	1.6	2368.0	-0.6	–	2371.6	-0.3	–
February	Albeni Falls	2054.9	0.2	0.4	2055.1	–	–	2055.8	–	–	2055.4	–	–
	Dworshak	1504.2	2.5	3.5	1505.0	0.5	1.2	1506.4	-0.3	–	1504.0	–	–
	Grand Coulee	1258.2	1.1	2.2	1260.9	–	0.5	1262.9	-0.5	-0.2	1262.1	-0.3	0.2
	Hungry Horse	3496.9	1.7	3.3	3490.9	–	1.0	3490.8	-1.2	-1.3	3491.9	-1.3	-0.5
	Libby	2340.1	2.3	3.9	2342.8	0.8	1.6	2336.5	-0.2	–	2341.5	–	–
March	Albeni Falls	2055.6	–	–	2055.6	–	–	2055.6	–	–	2055.6	–	–
	Dworshak	1477.4	1.1	1.4	1477.7	0.5	0.8	1479.5	–	0.2	1476.1	–	–
	Grand Coulee	1235.9	–	0.7	1236.2	0.5	1.0	1237.7	-0.4	–	1236.9	–	0.7
	Hungry Horse	3485.1	–	1.8	3477.4	–	1.4	3477.1	–	–	3478.3	-1.0	–
	Libby	2333.5	2.1	3.4	2335.0	0.9	1.6	2328.0	-0.2	–	2334.2	–	–

Table 4.2.5 (Continued)

Month	Project	1988 Elevation Existing	1988 Differences FM	1988 Differences AD	1993 Elevation Existing	1993 Differences FM	1993 Differences AD	1998 Elevation Existing	1998 Differences FM	1998 Differences AD	2003 Elevation Existing	2003 Differences FM	2003 Differences AD
April 1-15	Albeni Falls	2055.5	-	-	2055.4	-	-	2055.5	-	-	2055.5	-	-
	Dworshak	1487.6	0.9	1.1	1487.1	0.5	0.6	1490.5	-	-	1485.7	-	-
	Grand Coulee	1234.6	-0.5	0.5	1233.9	0.3	0.9	1234.5	-0.7	-0.3	1234.4	-	0.7
	Hungry Horse	3486.7	-	1.8	3478.6	-	1.2	3478.8	-	-	3480.6	-0.9	-
	Libby	2335.8	2.1	3.5	2336.4	1.1	1.7	2330.3	-0.2	-	2336.4	-	0.3
April 16-30	Albeni Falls	2055.4	-	-	2055.1	-	-	2055.6	-	-	2055.4	-	-
	Dworshak	1506.1	0.8	1.0	1505.5	0.4	0.4	1509.5	-0.2	-	1503.9	-	-
	Grand Coulee	1232.1	-	-	1231.4	0.5	0.5	1230.8	-	0.1	1231.3	0.1	0.3
	Hungry Horse	3493.2	-	-	3484.7	-	1.2	3484.0	-	-	3486.3	-0.8	-
	Libby	2344.7	2.0	3.2	2344.6	1.0	1.5	2339.5	-0.2	-	2344.7	-	0.3
May	Albeni Falls	2062.5	-	-	2062.4	-	-	2062.5	-	-	2062.4	-	-
	Dworshak	1560.1	0.8	1.0	1559.6	0.4	0.4	1559.8	-0.2	-	1557.5	-	-
	Grand Coulee	1254.2	-	-	1251.9	0.6	0.7	1252.4	-	-	1251.1	0.2	0.3
	Hungry Horse	3525.6	-	-	3520.3	-	0.9	3520.6	0.3	-	3519.7	-0.5	-
	Libby	2397.4	1.2	1.7	2397.0	0.7	1.0	2396.0	-	-	2395.1	-	-
June	Albeni Falls	2062.6	-	-	2062.7	-	-	2062.6	-	-	2062.6	-	-
	Dworshak	1591.3	0.7	0.8	1589.6	0.3	0.4	1588.7	-0.1	-	1588.8	-	0.1
	Grand Coulee	1286.9	-0.2	-0.1	1286.5	-	-	1286.3	-	-	1285.5	-	-
	Hungry Horse	3552.0	-	-	3546.4	-	0.7	3546.5	-	-	3546.6	-0.4	-
	Libby	2445.9	0.5	0.8	2444.0	0.4	0.6	2444.6	-	-	2444.1	-	-
July	Albeni Falls	2062.5	-	-	2062.5	-	-	2062.5	-	-	2062.5	-	-
	Dworshak	1593.4	-	0.5	1590.2	-	-	1588.6	-0.4	-	1589.3	-0.2	-
	Grand Coulee	1290.0	-	-	1290.0	-	-	1289.9	-	-	1290.0	-	-
	Hungry Horse	3554.1	-	-	3547.0	-	0.7	3546.2	-	-	3547.0	-0.3	-
	Libby	2455.5	0.6	0.8	2453.7	0.6	0.5	2453.7	-0.2	-	2453.6	-	-
August 1-15	Albeni Falls	2062.5	-	-	2062.5	-	-	2062.5	-	-	2062.5	-	-
	Dworshak	1592.5	-	-	1587.9	-	-	1586.6	-0.5	-0.3	1587.1	-0.4	-0.3
	Grand Coulee	1290.0	-	-	1290.0	-	-	1289.9	-	-	1290.0	-	-
	Hungry Horse	3553.4	-1.0	-1.1	3544.8	-	-	3543.8	-	-	3543.9	-0.5	-
	Libby	2455.5	0.5	0.6	2453.4	0.4	0.3	2453.1	-0.4	-0.2	2452.8	-0.4	-0.3
August 16-31	Albeni Falls	2062.5	-	-	2062.5	-	-	2062.5	-	-	2062.5	-	-
	Dworshak	1591.3	-0.6	-0.5	1585.4	-	-0.4	1584.5	-0.6	-0.5	1584.6	-0.6	-0.5
	Grand Coulee	1290.0	-	-	1290.0	-	-	1289.9	-	-	1290.0	-	-
	Hungry Horse	3552.4	-0.6	-1.7	3542.6	-	-	3541.6	-0.8	-0.6	3541.0	-1.1	-0.7
	Libby	2455.5	0.4	0.5	2453.3	0.4	-	2453.0	-0.4	-0.2	2452.6	-0.5	-0.4

Existing = Existing Contracts
FM = Federal Marketing
AD = Assured Delivery
- Indicates a difference which is not statistically significant or is less than 0.1 ft.
- A negative number indicates a lower elevation than the base condition.

(VS6-PG-1315I)

Table 4.2.6

EFFECTS OF LONG-TERM FIRM CONTRACTS ON RESERVOIR ELEVATIONS (FEET)

Assuming Proposed Formula Allocation and Maximum Capacity

		1988			1993			1998			2003		
		Elevation	Differences		Elevation	Differences		Elevation	Differences		Elevation	Differences	
Month	Project	Existing	FM	AD	Existing	FM	AD	Existing	FM	AD	Existing	FM	AD
September	Albeni Falls	2060.9	–	–	2060.8	–	–	2060.8	–	–	2061.0	-0.2	-0.1
	Dworshak	1575.8	-1.2	-0.7	1568.5	-2.2	-1.2	1567.5	-1.7	-2.4	1571.7	-1.9	-1.5
	Grand Coulee	1288.3	–	–	1288.0	–	–	1288.0	–	–	1288.3	-0.2	-0.1
	Hungry Horse	3546.1	-2.1	-1.3	3532.7	-3.7	-2.2	3530.6	-2.8	-3.6	3537.1	-2.6	-2.2
	Libby	2455.3	-0.4	–	2451.7	-1.2	-0.7	2451.2	-0.9	-1.3	2453.2	-0.8	-0.7
October	Albeni Falls	2057.4	–	–	2057.2	–	–	2057.4	–	–	2057.5	-0.2	-0.1
	Dworshak	1571.9	-1.0	0.7	1564.9	-2.3	-1.2	1564.2	-2.1	-2.6	1568.0	-2.1	-1.6
	Grand Coulee	1288.2	–	–	1288.0	–	–	1288.1	–	–	1288.3	-0.1	–
	Hungry Horse	3537.0	-2.0	-1.6	3524.1	-4.3	-2.0	3522.9	-3.5	-4.1	3529.0	-3.9	-2.9
	Libby	2448.1	1.1	2.4	2447.3	-2.2	-0.9	2447.4	-2.1	-2.1	2449.2	-2.0	-1.5
November	Albeni Falls	2052.6	–	–	2052.6	–	–	2052.6	–	–	2052.6	–	–
	Dworshak	1557.5	–	–	1553.4	-1.1	–	1553.8	-1.2	-1.6	1555.4	-1.5	-1.0
	Grand Coulee	1288.2	–	–	1288.3	-0.2	–	1288.2	-0.1	–	1288.4	-0.1	–
	Hungry Horse	3536.1	-1.9	-1.4	3523.3	-4.3	-1.9	3522.7	-3.5	-4.1	3528.1	-4.0	-3.0
	Libby	2435.9	2.4	4.1	2437.8	-0.9	0.7	2438.2	-1.1	-1.1	2439.4	-1.2	-0.7
December	Albeni Falls	2052.8	–	0.1	2053.2	–	–	2053.3	–	–	2053.1	–	–
	Dworshak	1546.3	3.8	5.2	1549.5	-0.8	–	1549.5	-0.8	-0.9	1550.0	-0.7	-0.3
	Grand Coulee	1287.2	–	–	1287.5	–	–	1287.6	–	–	1287.4	–	–
	Hungry Horse	3525.2	–	–	3516.2	-3.4	–	3515.5	-3.4	-3.2	3519.9	-4.0	-2.4
	Libby	2400.9	4.0	6.7	2406.7	–	1.2	2406.9	-0.7	-0.4	2407.7	-0.6	–
January	Albeni Falls	2054.2	0.4	0.7	2055.0	–	–	2055.3	–	0.1	2055.0	–	–
	Dworshak	1526.2	3.0	4.3	1527.0	–	1.1	1528.1	-0.5	-0.5	1527.0	-0.5	–
	Grand Coulee	1275.3	1.4	2.2	1278.3	–	0.4	1278.7	-0.3	0.6	1278.4	-0.3	–
	Hungry Horse	3508.8	2.0	4.4	3504.5	-2.2	–	3504.0	-2.1	-1.4	3506.2	-2.4	-1.1
	Libby	2365.8	4.2	6.8	2371.1	–	1.8	2367.9	-0.6	–	2371.4	-0.5	–
February	Albeni Falls	2054.9	0.2	0.4	2055.2	–	–	2055.7	–	0.1	2055.4	–	–
	Dworshak	1504.2	2.5	3.5	1504.9	0.5	1.3	1506.3	-0.3	-0.2	1504.0	-0.3	–
	Grand Coulee	1258.2	1.1	2.2	1261.4	-0.3	0.5	1262.8	-0.4	0.6	1261.9	-0.3	0.1
	Hungry Horse	3496.9	1.7	3.3	3490.9	-0.9	1.1	3490.5	-1.0	-0.8	3491.6	-1.3	-0.8
	Libby	2340.1	2.3	3.9	2342.8	0.6	1.5	2336.3	-0.2	–	2341.5	–	–
March	Albeni Falls	2055.6	–	–	2055.6	–	–	2055.6	–	–	2055.6	–	–
	Dworshak	1477.4	1.1	1.4	1477.7	0.5	0.8	1479.4	–	–	1476.2	–	–
	Grand Coulee	1235.9	–	0.7	1236.7	–	0.5	1237.4	–	0.6	1236.3	–	0.5
	Hungry Horse	3485.1	–	1.8	3477.2	–	1.4	3476.7	–	–	3477.8	-1.1	-0.6
	Libby	2333.5	2.1	3.4	2335.0	0.8	1.6	2327.9	–	–	2334.2	–	–

Table 4.2.6 (Continued)

Month	Project	1988 Elevation Existing	1988 Differences FM	1988 Differences AD	1993 Elevation Existing	1993 Differences FM	1993 Differences AD	1998 Elevation Existing	1998 Differences FM	1998 Differences AD	2003 Elevation Existing	2003 Differences FM	2003 Differences AD
April 1-15	Albeni Falls	2055.5	–	–	2055.4	–	–	2055.5	–	–	2055.5	–	–
	Dworshak	1487.6	0.9	1.1	1487.1	0.4	0.5	1490.5	-0.2	–	1485.8	–	–
	Grand Coulee	1234.6	-0.5	0.5	1234.1	–	0.7	1233.8	–	0.8	1233.4	–	0.4
	Hungry Horse	3486.7	–	1.8	3478.4	–	1.3	3478.4	–	–	3480.1	-1.0	-0.6
	Libby	2335.8	2.1	3.5	2336.4	0.9	1.6	2330.2	–	–	2336.5	–	–
April 16-30	Albeni Falls	2055.4	–	–	2055.1	–	–	2055.5	–	–	2055.2	–	–
	Dworshak	1506.1	0.8	1.0	1505.5	0.3	0.4	1509.5	-0.3	-0.2	1503.9	–	–
	Grand Coulee	1232.1	–	–	1231.5	0.4	0.5	1230.8	–	0.2	1231.3	0.1	0.3
	Hungry Horse	3493.2	–	–	3484.7	–	1.2	3483.6	–	–	3485.8	-0.8	-0.5
	Libby	2344.7	2.0	3.2	2344.7	0.8	1.5	2339.4	–	–	2344.7	–	–
May	Albeni Falls	2062.5	–	–	2062.4	–	–	2062.5	–	–	2062.4	–	–
	Dworshak	1560.1	0.8	1.0	1559.6	0.3	0.4	1559.8	-0.3	–	1557.5	–	–
	Grand Coulee	1254.2	–	–	1252.3	0.5	0.5	1252.4	–	0.1	1250.9	0.2	0.3
	Hungry Horse	3525.6	–	–	3520.3	–	0.8	3520.4	–	–	3519.5	-0.5	-0.4
	Libby	2397.4	1.2	1.7	2397.0	0.6	0.9	2396.0	–	–	2395.1	–	–
June	Albeni Falls	2062.6	–	–	2062.7	–	–	2062.6	–	–	2062.6	–	–
	Dworshak	1591.3	0.7	0.8	1589.6	–	0.3	1588.7	-0.2	–	1588.8	–	0.1
	Grand Coulee	1286.9	-0.2	-0.1	1286.6	–	–	1286.2	–	–	1285.5	–	–
	Hungry Horse	3552.0	–	–	3546.3	–	–	3546.4	–	–	3546.5	-0.4	–
	Libby	2445.9	0.5	0.8	2444.0	0.3	0.6	2444.6	–	–	2444.2	–	–
July	Albeni Falls	2062.5	–	–	2062.5	–	–	2062.5	–	–	2062.5	–	–
	Dworshak	1593.4	–	0.5	1590.2	–	–	1588.6	-0.4	-0.1	1589.4	-0.2	–
	Grand Coulee	1290.0	–	–	1290.0	–	–	1289.9	–	–	1289.9	–	–
	Hungry Horse	3554.1	–	–	3547.0	–	–	3546.1	–	–	3547.0	-0.4	–
	Libby	2455.5	0.6	0.8	2453.7	0.5	0.6	2453.6	-0.1	–	2453.6	–	–
August 1-15	Albeni Falls	2062.5	–	–	2062.5	–	–	2062.5	–	–	2062.5	–	–
	Dworshak	1592.5	–	–	1588.0	–	-0.3	1586.5	-0.6	-0.4	1587.0	-0.5	-0.3
	Grand Coulee	1290.0	–	–	1290.0	–	–	1289.9	–	–	1289.9	–	–
	Hungry Horse	3553.4	-1.0	-1.1	3544.7	–	–	3543.6	-0.5	–	3543.9	-0.7	-0.3
	Libby	2455.5	0.5	0.6	2453.3	0.4	0.4	2453.1	-0.4	-0.2	2452.8	-0.4	-0.3
August 16-31	Albeni Falls	2062.5	–	–	2062.5	–	–	2062.5	–	–	2062.5	–	–
	Dworshak	1591.3	-0.6	-0.5	1585.3	–	-0.5	1584.3	-0.7	-0.5	1584.5	-0.7	-0.5
	Grand Coulee	1290.0	–	–	1290.0	–	–	1289.9	–	–	1290.0	–	–
	Hungry Horse	3552.4	-1.6	-1.7	3542.4	–	–	3541.3	-0.9	-0.7	3540.9	-1.2	-0.9
	Libby	2455.5	0.4	0.5	2453.2	0.3	0.3	2452.9	-0.4	-0.3	2452.6	-0.5	-0.4

Existing = Existing Contracts
FM = Federal Marketing
AD = Assured Delivery
– Indicates a difference which is not statistically significant or is less than 0.1 ft.
– A negative number indicates a lower elevation than the base condition.

(VS6-PG-1315I)

Table 4.2.7

EFFECTS OF INTERTIE CAPACITY ON OVERGENERATION

Assuming Proposed Formula Allocation and Existing Contracts

	Existing Capacity	DC Upgrade		Maximum Capacity	
	Spill (MW)	Spill (MW)	Change (MW)	Spill (MW)	Change (MW)
September	0	0	0	0	0
October	0	0	0	0	0
November	0	0	0	0	0
December	0.3	0	-0.3	0	-0.3
January	14.5	2.6	-11.9	0	-14.5
February	37.2	4.5	-32.7	0	-37.2
March	287.1	116.8	-170.3	6.7	-280.4
April	251.7	86.4	-165.3	2.2	-249.5
May	946.9	502.7	-444.2	120.6	-826.3
June	1329.2	868.6	-460.6	413.7	-915.5
July	460.9	161.4	-299.5	12.5	-448.4
August	0.1	0	-0.1	0	-0.1
Average	277.3	145.2	-132.1	46.3	-231.0

(VS6-PG-1315I)

Table 4.2.8a

EFFECTS OF MAXIMUM CAPACITY ON RESERVOIR ELEVATIONS (feet)

Assuming Proposed Formula Allocation and Existing Contracts
with Low Northwest Loads

Month	Project	1993 Elevation at Existing Capacity	1993 Changes in Elevation at Maximum Capacity	1998 Elevation at Existing Capacity	1998 Changes in Elevation at Maximum Capacity	2003 Elevation at Existing Capacity	2003 Changes in Elevation at Maximum Capacity
September	Albeni Falls	2060.8	–	2060.8	-0.1	2060.9	-0.1
	Dworshak	1567.7	-0.8	1567.5	-0.6	1571.4	-0.7
	Grand Coulee	1288.0	-0.2	1288.0	-0.2	1288.2	-0.2
	Hungry Horse	3530.8	-1.3	3530.1	-1.3	3537.1	-0.9
	Libby	2450.4	-0.5	2450.5	-0.3	2452.9	-0.2
October	Albeni Falls	2057.3	-0.2	2057.6	-0.5	2057.5	-0.2
	Dworshak	1563.7	-1.1	1564.3	-1.5	1567.4	-0.8
	Grand Coulee	1288.0	-0.2	1288.2	-0.4	1288.3	-0.1
	Hungry Horse	3520.9	-1.9	3521.9	-2.7	3527.6	-1.3
	Libby	2444.4	-0.9	2445.3	-1.8	2446.5	-0.7
November	Albeni Falls	2052.6	–	2052.6	–	2052.6	–
	Dworshak	1551.6	-0.5	1553.1	-1.7	1554.0	-0.8
	Grand Coulee	1288.1	–	1288.3	-0.6	1288.4	-0.2
	Hungry Horse	3519.3	-1.1	3521.4	-2.3	3526.1	-1.4
	Libby	2433.2	–	2434.5	-3.1	2434.5	-1.6
December	Albeni Falls	2053.1	-0.3	2053.5	-0.6	2053.7	-0.8
	Dworshak	1545.2	-1.0	1545.4	-2.5	1544.6	-2.3
	Grand Coulee	1287.5	-0.3	1287.6	-0.7	1288.0	-0.7
	Hungry Horse	3511.0	-2.5	3514.1	-4.8	3518.7	-5.1
	Libby	2401.0	-1.2	2401.4	-3.1	2401.2	-2.4
January	Albeni Falls	2054.6	-0.6	2055.5	-1.1	2055.8	-1.7
	Dworshak	1524.1	-0.7	1524.9	-0.9	1521.9	-1.1
	Grand Coulee	1277.0	-2.1	1279.1	-4.0	1281.0	-5.8
	Hungry Horse	3499.3	-4.0	3502.0	-6.0	3504.9	-7.7
	Libby	2367.4	-0.9	2364.1	-2.5	2366.8	-2.9
February	Albeni Falls	2055.2	-0.6	2056.5	-1.4	2056.8	-1.8
	Dworshak	1502.6	-0.4	1504.5	-0.7	1501.0	-1.8
	Grand Coulee	1261.5	-3.7	1267.0	-8.4	1269.7	-10.3
	Hungry Horse	3487.2	-3.4	3490.5	-5.8	3491.6	-7.0
	Libby	2341.4	-0.8	2335.7	-1.7	2340.4	-1.6
March	Albeni Falls	2055.6	-0.1	2055.7	-0.2	2055.8	-0.2
	Dworshak	1476.8	–	1478.6	-0.1	1474.6	–
	Grand Coulee	1240.0	-5.0	1246.5	-11.4	1247.0	-10.8
	Hungry Horse	3476.5	-3.8	3478.3	-4.6	3477.5	-4.4
	Libby	2333.9	-0.6	2327.3	-1.0	2332.6	-0.5

Table 4.2.8a [Continued]

Month	Project	1993 Elevation at Existing Capacity	1993 Changes in Elevation at Maximum Capacity	1998 Elevation at Existing Capacity	1998 Changes in Elevation at Maximum Capacity	2003 Elevation at Existing Capacity	2003 Changes in Elevation at Maximum Capacity
April 1-15	Albeni Falls	2055.5	-0.2	2055.7	-0.3	2055.7	-0.2
	Dworshak	1486.2	-0.2	1489.9	-0.2	1484.6	-0.1
	Grand Coulee	1236.5	-4.5	1240.0	-8.1	1240.7	-6.6
	Hungry Horse	3477.7	-3.4	3479.5	-4.4	3479.3	-3.8
	Libby	2335.4	-0.6	2329.5	-1.0	2334.8	-0.5
April 16-30	Albeni Falls	2055.3	-0.3	2056.0	-0.6	2055.8	-0.5
	Dworshak	1504.5	-	1509.0	-	1502.8	-
	Grand Coulee	1231.2	-0.5	1231.9	-1.9	1231.8	-1.4
	Hungry Horse	3483.9	-2.9	3485.6	-4.6	3485.9	-3.6
	Libby	2343.6	-0.4	2338.8	-1.0	2343.0	-0.4
May	Albeni Falls	2062.4	-	2062.5	-	2062.4	-0.1
	Dworshak	1558.6	-	1559.3	-	1556.4	-
	Grand Coulee	1252.3	-0.3	1253.8	-1.8	1251.4	-0.5
	Hungry Horse	3518.6	-0.9	3520.6	-2.2	3518.5	-1.7
	Libby	2396.1	-0.3	2395.3	-0.6	2394.0	-0.2
June	Albeni Falls	2062.7	-	2062.6	-	2062.6	-
	Dworshak	1588.3	-0.2	1588.5	-	1588.2	-
	Grand Coulee	1286.3	-0.1	1286.4	-0.2	1285.6	-0.1
	Hungry Horse	3544.5	-0.5	3546.8	-1.4	3545.6	-1.1
	Libby	2443.6	-0.5	2444.4	-0.8	2443.5	-0.4
July	Albeni Falls	2062.5	-	2062.5	-	2062.5	-
	Dworshak	1589.[illegible]	-	1589.2	-0.1	1589.8	-
	Grand Coulee	1289.9	-	1289.9	-	1289.9	-
	Hungry Horse	3545.1	-0.4	3547.0	-0.6	3546.6	-0.6
	Libby	2453.1	-0.2	2453.4	-0.2	2453.1	-
August 1-15	Albeni Falls	2062.5	-	2062.5	-	2062.5	-
	Dworshak	1587.3	-	1587.9	-0.1	1588.5	-
	Grand Coulee	1290.0	-	1289.9	-	1289.9	-
	Hungry Horse	3543.5	-0.4	3545.6	-0.6	3545.1	-0.6
	Libby	2453.1	-0.2	2453.5	-0.2	2453.2	-
August 16-31	Albeni Falls	2062.5	-	2062.5	-	2062.5	-
	Dworshak	1585.6	-0.2	1586.4	-0.2	1586.8	-
	Grand Coulee	1290.0	-	1290.0	-	1289.9	-
	Hungry Horse	3542.0	-0.4	3544.3	-0.6	3543.6	-0.6
	Libby	2453.2	-0.2	2453.5	-0.2	2453.2	-

- A negative number indicates an alternative which has a lower elevation than the base case.
- A dash indicates a difference which is not statistically significant or is less than 0.1 foot.

(VS6-PG-1315I)

Table 4.2.8b

EFFECTS OF ALTERNATIVE LONG-TERM FIRM CONTRACTS ON RESERVOIR ELEVATIONS (feet)

Assuming Proposed Formula Allocation and Existing Capacity

		1988			1993			1998			2003		
		Elevation	Differences		Elevation	Differences		Elevation	Differences		Elevation	Differences	
Month	Project	Existing	PI	AD	Existing	PI	AD	Existing	PI	AD	Existing	PI	AD
September	Albeni Falls	2060.9	-	-	2060.8	-	-	2060.8	-	-	2061.0	-	-
	Dworshak	1575.8	-2.1	-0.7	1568.5	-2.6	-1.5	1567.6	-2.6	-2.3	1571.8	-	-1.4
	Grand Coulee	1288.3	-	-	1288.0	0.1	-	1288.0	-	-	1288.3	-	-0.1
	Hungry Horse	3546.1	-3.6	-1.3	3533.0	-3.7	-2.3	3530.8	-3.5	-3.5	3537.5	-	-2.1
	Libby	2455.3	-0.7	-	2451.8	-1.5	-0.8	2451.3	-1.4	-1.2	2453.2	-	-0.6
October	Albeni Falls	2057.4	-	-	2057.2	0.2	-	2057.4	-	-	2057.6	-	-
	Dworshak	1571.9	-2.2	-0.7	1565.1	-2.4	-1.4	1564.4	-2.3	-2.6	1568.2	-	-1.5
	Grand Coulee	1288.2	-	-	1288.0	0.1	-	1288.1	-	-	1288.3	-	-
	Hungry Horse	3537.0	-4.4	-1.6	3524.3	-3.1	-2.2	3523.2	-3.4	-4.1	3529.6	-	-2.8
	Libby	2448.1	-0.4	2.4	2447.4	-1.8	-0.9	2447.6	-1.7	-2.1	2449.5	-0.3	-1.4
November	Albeni Falls	2052.6	-	-	2052.6	-	-	2052.6	-	-	2052.6	-	-
	Dworshak	1557.5	-1.3	-	1553.4	-1.1	-0.4	1554.0	-1.3	-1.6	1555.6	0.3	-0.9
	Grand Coulee	1288.2	-	-	1288.2	0.2	0.1	1288.2	-	-	1288.4	0.3	-
	Hungry Horse	3536.1	-4.2	-1.4	3523.7	-3.1	-2.0	3523.0	-3.3	-4.0	3528.7	-	-2.8
	Libby	2435.9	1.9	4.1	2437.3	0.5	1.1	2438.3	-	-1.0	2439.5	1.0	-0.5
December	Albeni Falls	2052.8	-	0.1	2053.2	0.2	0.1	2053.3	0.1	-	2053.1	0.4	-
	Dworshak	1546.3	3.6	5.2	1549.5	-	-	1549.6	-0.5	-0.9	1550.1	1.0	-0.2
	Grand Coulee	1287.2	-	-	1287.5	0.2	-	1287.6	-	-	1287.4	0.3	-
	Hungry Horse	3525.2	-2.9	-	3516.6	-1.9	-	3515.8	-1.2	-3.3	3520.5	2.2	-2.0
	Libby	2400.9	4.0	6.7	2406.7	0.6	1.2	2407.0	0.5	-0.3	2407.8	0.8	-
January	Albeni Falls	2054.2	0.4	0.7	2054.8	0.2	0.1	2055.3	-	-	2055.0	0.3	-
	Dworshak	1526.2	3.1	4.3	1527.1	0.5	0.9	1528.2	-	-0.4	1527.0	1.5	-
	Grand Coulee	1275.3	1.4	2.2	1277.7	0.7	0.6	1278.7	0.3	-0.1	1278.5	0.9	0.1
	Hungry Horse	3508.8	-	4.4	3504.5	-1.3	-	3504.3	-	-2.0	3506.8	2.8	-1.0
	Libby	2365.8	4.2	6.8	2371.2	0.9	1.6	2368.0	1.2	-	2371.6	1.7	-
February	Albeni Falls	2054.9	0.2	0.4	2055.1	-	-	2055.8	-	-	2055.4	0.3	-
	Dworshak	1504.2	2.6	3.5	1505.0	0.8	1.2	1506.4	0.9	-	1504.0	1.6	-
	Grand Coulee	1258.2	1.1	2.2	1260.9	0.3	0.5	1262.9	0.4	-0.2	1262.1	1.7	0.2
	Hungry Horse	3496.9	1.3	3.3	3490.9	-	1.0	3490.8	-	-1.3	3491.9	3.0	-0.5
	Libby	2340.1	2.6	3.9	2342.8	0.8	1.6	2336.5	1.3	-	2341.5	2.4	-
March	Albeni Falls	2055.6	-	-	2055.6	-	-	2055.6	-	-	2055.6	-	-
	Dworshak	1477.4	1.2	1.4	1477.7	0.5	0.8	1479.5	0.7	0.2	1476.1	1.0	-
	Grand Coulee	1235.9	-	0.7	1236.2	0.9	1.0	1237.7	0.9	-	1236.9	3.6	0.7
	Hungry Horse	3485.1	-	1.8	3477.4	-	1.4	3477.1	-	-	3478.3	4.0	-
	Libby	2333.5	2.4	3.4	2335.0	1.0	1.6	2328.0	1.2	-	2334.2	2.6	-

Table 4.2.8b (Continued)

Month	Project	1988 Elevation Existing	1988 Differences P1	1988 Differences AD	1993 Elevation Existing	1993 Differences P1	1993 Differences AD	1998 Elevation Existing	1998 Differences P1	1998 Differences AD	2003 Elevation Existing	2003 Differences P1	2003 Differences AD
April 1-15	Albeni Falls	2055.5	–	–	2055.4	–	–	2055.5	–	–	2055.5	–	–
	Dworshak	1487.6	1.0	1.1	1487.1	–	0.6	1490.5	0.8	–	1485.7	1.0	–
	Grand Coulee	1234.6	-0.6	0.5	1233.9	0.6	0.9	1234.5	0.9	-0.3	1234.4	3.1	0.7
	Hungry Horse	3486.7	–	1.8	3478.6	–	1.2	3478.8	–	–	3480.6	3.8	–
	Libby	2335.8	2.4	3.5	2336.4	1.0	1.7	2330.3	1.3	–	2336.4	2.8	0.3
April 16-30	Albeni Falls	2055.4	–	–	2055.1	–	–	2055.6	–	–	2055.4	0.1	–
	Dworshak	1506.1	0.9	1.0	1505.5	–	0.4	1509.5	0.8	–	1503.9	1.0	–
	Grand Coulee	1232.1	–	–	1231.4	–	0.5	1230.8	1.0	0.1	1231.3	1.5	0.3
	Hungry Horse	3493.2	–	–	3484.7	–	1.2	3484.0	1.0	–	3486.3	3.1	–
	Libby	2344.7	2.2	3.2	2344.6	0.9	1.5	2339.5	1.3	–	2344.7	2.7	0.3
May	Albeni Falls	2062.5	–	–	2062.4	–	–	2062.5	–	–	2062.4	–	–
	Dworshak	1560.1	0.8	1.0	1559.6	–	0.4	1559.8	0.8	–	1557.5	1.0	–
	Grand Coulee	1254.2	–	–	1251.9	0.6	0.7	1252.4	0.8	–	1251.1	1.3	0.3
	Hungry Horse	3525.6	–	–	3520.3	–	0.9	3520.6	0.8	–	3519.7	1.8	–
	Libby	2397.4	1.4	1.7	2397.0	0.8	1.0	2396.0	0.8	–	2395.1	1.8	–
June	Albeni Falls	2062.6	–	–	2062.7	–	–	2062.6	–	–	2062.6	–	–
	Dworshak	1591.3	0.7	0.8	1589.6	–	0.4	1588.7	0.9	–	1588.8	1.0	0.1
	Grand Coulee	1286.9	-0.2	-0.1	1286.5	–	–	1286.3	0.2	–	1285.5	0.3	–
	Hungry Horse	3552.0	–	–	3546.4	–	0.7	3546.5	1.3	–	3546.6	1.6	–
	Libby	2445.9	0.7	0.8	2444.0	0.4	0.6	2444.6	0.5	–	2444.1	1.1	–
July	Albeni Falls	2062.5	–	–	2062.5	–	–	2062.5	–	–	2062.5	–	–
	Dworshak	1593.4	–	0.5	1590.2	-0.8	–	1588.6	1.0	–	1589.3	0.4	–
	Grand Coulee	1290.0	–	–	1290.0	–	–	1289.9	–	–	1290.0	–	–
	Hungry Horse	3554.1	–	–	3547.0	–	0.7	3546.2	1.8	–	3547.0	1.5	–
	Libby	2455.5	0.7	0.8	2453.7	–	0.5	2453.7	0.6	–	2453.6	0.5	–
August 1-15	Albeni Falls	2062.5	–	–	2062.5	–	–	2062.5	–	–	2062.5	–	–
	Dworshak	1592.5	-0.4	–	1587.9	-1.2	–	1586.6	1.2	-0.3	1587.1	0.5	-0.3
	Grand Coulee	1290.0	–	–	1290.0	–	–	1289.9	–	–	1290.0	–	–
	Hungry Horse	3553.4	-1.3	-1.1	3544.8	-1.1	–	3543.8	1.9	–	3543.9	1.5	–
	Libby	2455.5	0.5	0.6	2453.4	–	0.3	2453.1	0.7	-0.2	2452.8	0.5	-0.3
August 16-31	Albeni Falls	2062.5	–	–	2062.5	–	–	2062.5	–	–	2062.5	–	–
	Dworshak	1591.3	-0.8	-0.5	1585.4	-1.4	-0.4	1584.5	1.2	-0.5	1584.6	0.7	-0.5
	Grand Coulee	1290.0	–	–	1290.0	–	–	1289.9	–	–	1290.0	–	–
	Hungry Horse	3552.4	-1.9	-1.7	3542.6	-2.1	–	3541.6	1.9	-0.6	3541.0	1.5	-0.7
	Libby	2455.5	0.4	0.5	2453.3	-0.4	–	2453.0	0.7	-0.2	2452.6	0.6	-0.4

Existing = Existing Contracts
P1 = Assured Delivery Alternative 1
AD = Assured Delivery
– Indicates a difference which is not statistically significant or is less than 0.1 ft.
– A negative number indicates a lower elevation than the base condition.

(VS6-PG-6215K)

Table 4.2.8c

EFFECTS OF ALTERNATIVE LONG-TERM FIRM CONTRACTS ON RESERVOIR ELEVATIONS (feet)

Assuming Proposed Formula Allocation and Maximum Capacity

		1988			1993		
		Elevation	Differences		Elevation	Differences	
Month	Project	Existing	P2	AD	Existing	P2	AD
September	Albeni Falls	2060.9	–	–	2060.8	–	–
	Dworshak	1575.8	-3.5	-0.7	1568.5	-3.7	-1.2
	Grand Coulee	1288.3	–	–	1288.0	–	–
	Hungry Horse	3546.1	-6.8	-1.3	3532.7	-5.0	-2.2
	Libby	2455.3	-1.5	–	2451.7	-2.3	-0.7
October	Albeni Falls	2057.4	–	–	2057.2	0.2	–
	Dworshak	1571.9	-3.7	0.7	1564.9	-3.3	-1.2
	Grand Coulee	1288.2	–	–	1288.0	0.1	–
	Hungry Horse	3537.0	-8.1	-1.6	3524.1	-4.7	-2.0
	Libby	2448.1	-3.8	2.4	2447.3	-2.9	-0.9
November	Albeni Falls	2052.6	–	–	2052.6	–	–
	Dworshak	1557.5	-2.3	–	1553.4	-1.5	–
	Grand Coulee	1288.2	–	–	1288.3	–	–
	Hungry Horse	3536.1	-7.9	-1.4	3523.3	-4.5	-1.9
	Libby	2435.9	–	4.1	2437.8	–	0.7
December	Albeni Falls	2052.8	–	0.1	2053.2	0.2	–
	Dworshak	1546.3	2.2	5.2	1549.5	-0.8	–
	Grand Coulee	1287.2	–	–	1287.5	0.2	–
	Hungry Horse	3525.2	-7.0	–	3516.2	-2.9	–
	Libby	2400.9	1.5	6.7	2406.7	–	1.2
January	Albeni Falls	2054.2	0.1	0.7	2055.0	–	–
	Dworshak	1526.2	2.0	4.3	1527.0	–	1.1
	Grand Coulee	1275.3	0.4	2.2	1278.3	0.3	0.4
	Hungry Horse	3508.8	-2.4	4.4	3504.5	-2.0	–
	Libby	2365.8	1.4	6.8	2371.1	–	1.8
February	Albeni Falls	2054.9	–	0.4	2055.2	–	–
	Dworshak	1504.2	1.8	3.5	1504.9	–	1.3
	Grand Coulee	1258.2	–	2.2	1261.4	–	0.5
	Hungry Horse	3496.9	-1.1	3.3	3490.9	-1.3	1.1
	Libby	2340.1	1.1	3.9	2342.8	–	1.5
March	Albeni Falls	2055.6	–	–	2055.6	–	–
	Dworshak	1477.4	0.8	1.4	1477.7	–	0.8
	Grand Coulee	1235.9	0.3	0.7	1236.7	0.6	0.5
	Hungry Horse	3485.1	–	1.8	3477.2	–	1.4
	Libby	2333.5	1.0	3.4	2335.0	–	1.6

		1998			2003		
		Elevation	Differences		Elevation	Differences	
Month	Project	Existing	P2	AD	Existing	P2	AD
September	Albeni Falls	2060.8	–	–	2061.0	–	-0.1
	Dworshak	1567.5	-3.1	-2.4	1571.7	-0.8	-1.5
	Grand Coulee	1288.0	–	–	1288.3	–	-0.1
	Hungry Horse	3530.6	-4.4	-3.6	3537.1	-1.3	-2.2
	Libby	2451.2	-1.9	-1.3	2453.2	-0.3	-0.7
October	Albeni Falls	2057.4	–	–	2057.5	-0.1	-0.1
	Dworshak	1564.2	-3.1	-2.6	1568.0	-0.9	-1.6
	Grand Coulee	1288.1	–	–	1288.3	–	–
	Hungry Horse	3522.9	-4.4	-4.1	3529.0	-1.8	-2.9
	Libby	2447.4	-2.4	-2.1	2449.2	-1.3	-1.5
November	Albeni Falls	2052.6	–	–	2052.6	–	–
	Dworshak	1553.8	-1.7	-1.6	1555.4	–	-1.0
	Grand Coulee	1288.2	0.1	–	1288.4	0.2	–
	Hungry Horse	3522.7	-4.1	-4.1	3528.1	-1.6	-3.0
	Libby	2438.2	–	-1.1	2439.4	0.8	-0.7
December	Albeni Falls	2053.3	0.4	–	2053.1	0.3	–
	Dworshak	1549.5	–	-0.9	1550.0	0.9	-0.3
	Grand Coulee	1287.6	0.3	–	1287.4	0.2	–
	Hungry Horse	3515.5	–	-3.2	3519.9	1.1	-2.4
	Libby	2406.9	0.6	-0.4	2407.7	0.9	–
January	Albeni Falls	2055.3	0.2	0.1	2055.0	0.2	–
	Dworshak	1528.1	0.5	-0.5	1527.0	1.5	–
	Grand Coulee	1278.7	0.7	0.6	1278.4	0.8	–
	Hungry Horse	3504.0	–	-1.4	3506.2	2.1	-1.1
	Libby	2367.9	1.4	–	2371.4	1.7	–
February	Albeni Falls	2055.7	0.2	0.1	2055.4	0.2	–
	Dworshak	1506.3	1.1	-0.2	1504.0	1.7	–
	Grand Coulee	1262.8	0.9	0.6	1261.9	0.9	0.1
	Hungry Horse	3490.5	–	-0.8	3491.6	2.1	-0.8
	Libby	2336.3	1.7	–	2341.5	2.3	–
March	Albeni Falls	2055.6	–	–	2055.6	–	–
	Dworshak	1479.4	0.7	–	1476.2	0.9	–
	Grand Coulee	1237.4	1.3	0.6	1236.3	1.6	0.5
	Hungry Horse	3476.7	–	–	3477.8	2.6	-0.6
	Libby	2327.9	1.6	–	2334.2	2.5	–

Table 4.2.8c (Continued)

Month	Project	1988 Elevation Existing	1988 Differences P2	1988 Differences P2	1993 Elevation Existing	1993 Differences P2	1993 Differences AD	1998 Elevation Existing	1998 Differences P2	1998 Differences AD	2003 Elevation Existing	2003 Differences P2	2003 Differences AD
April 1-15	Albeni Falls	2055.5	–	–	2055.4	–	–	2055.5	–	–	2055.5	–	–
	Dworshak	1487.6	0.7	1.1	1487.1	–	0.5	1490.5	0.9	–	1485.8	1.0	–
	Grand Coulee	1234.6	–	0.5	1234.1	–	0.7	1233.8	1.7	0.8	1233.4	1.6	0.4
	Hungry Horse	3486.7	–	1.8	3478.4	–	1.3	3478.4	–	–	3480.1	2.5	-0.6
	Libby	2335.8	1.1	3.5	2336.4	–	1.6	2330.2	1.7	–	2336.5	2.8	–
April 16-30	Albeni Falls	2055.4	–	–	2055.1	–	–	2055.5	–	–	2055.2	–	–
	Dworshak	1506.1	0.6	1.0	1505.5	–	0.4	1509.5	0.9	-0.2	1503.9	1.0	–
	Grand Coulee	1232.1	–	–	1231.5	–	0.5	1230.8	1.1	0.2	1231.3	1.2	0.3
	Hungry Horse	3493.2	–	–	3484.7	–	1.2	3483.6	1.1	–	3485.8	2.2	-0.5
	Libby	2344.7	1.1	3.2	2344.7	–	1.5	2339.4	1.6	–	2344.7	2.7	–
May	Albeni Falls	2062.5	–	–	2062.4	–	–	2062.5	–	–	2062.4	–	–
	Dworshak	1560.1	0.6	1.0	1559.6	–	0.4	1559.8	0.9	–	1557.5	1.0	–
	Grand Coulee	1254.2	–	–	1252.3	–	0.5	1252.4	1.0	0.1	1250.9	1.4	0.3
	Hungry Horse	3525.6	–	–	3520.3	–	0.8	3520.4	0.7	–	3519.5	1.5	-0.4
	Libby	2397.4	0.7	1.7	2397.0	0.4	0.9	2396.0	1.0	–	2395.1	1.9	–
June	Albeni Falls	2062.6	–	–	2062.7	–	–	2062.6	–	–	2062.6	–	–
	Dworshak	1591.3	0.5	0.8	1589.6	-0.6	0.3	1588.7	1.0	–	1588.8	1.0	0.1
	Grand Coulee	1286.9	-0.1	-0.1	1286.6	-0.2	–	1286.2	0.2	–	1285.5	0.3	–
	Hungry Horse	3552.0	–	–	3546.3	–	–	3546.4	1.1	–	3546.5	1.4	–
	Libby	2445.9	0.4	0.8	2444.0	–	0.6	2444.6	0.7	–	2444.2	1.0	–
July	Albeni Falls	2062.5	–	–	2062.5	–	–	2062.5	–	–	2062.5	–	–
	Dworshak	1593.4	–	0.5	1590.2	-1.5	–	1588.6	1.0	-0.1	1589.4	–	–
	Grand Coulee	1290.0	–	–	1290.0	–	–	1289.9	–	–	1289.9	–	–
	Hungry Horse	3554.1	–	–	3547.0	-1.2	–	3546.1	1.5	–	3547.0	1.2	–
	Libby	2455.5	0.4	0.8	2453.7	–	0.6	2453.6	0.6	–	2453.6	0.4	–
August 1-15	Albeni Falls	2062.5	–	–	2062.5	–	–	2062.5	–	–	2062.5	–	–
	Dworshak	1592.5	-0.5	–	1588.0	-2.0	-0.3	1586.5	0.9	-0.4	1587.0	0.3	-0.3
	Grand Coulee	1290.0	–	–	1290.0	–	–	1289.9	–	–	1289.9	–	–
	Hungry Horse	3553.4	-1.3	-1.1	3544.7	-1.9	–	3543.6	1.5	–	3543.9	1.0	-0.3
	Libby	2455.5	–	0.6	2453.3	-0.6	0.4	2453.1	0.6	-0.2	2452.8	0.3	-0.3
August 16-31	Albeni Falls	2062.5	–	–	2062.5	–	–	2062.5	–	–	2062.5	–	–
	Dworshak	1591.3	-0.9	-0.5	1585.3	-2.2	-0.5	1584.3	0.9	-0.5	1584.5	0.3	-0.5
	Grand Coulee	1290.0	–	–	1290.0	–	–	1289.9	–	–	1290.0	–	–
	Hungry Horse	3552.4	-1.9	-1.7	3542.4	-3.0	–	3541.3	1.2	-0.7	3540.9	0.8	-0.9
	Libby	2455.5	–	0.5	2453.2	-0.9	0.3	2452.9	0.6	-0.3	2452.6	0.3	-0.4

Existing = Existing Contracts
P2 = Assured Delivery Alternative 2
AD = Assured Delivery
– Indicates a difference which is not statistically significant or is less than 0.1 ft.
– A negative number indicates a lower elevation than the base condition.

(VS6-PG-6215K)

Table 4.2.8d

EFFECTS OF LONG-TERM FIRM CONTRACTS ON RESERVOIR ELEVATIONS (feet)

Assuming Proposed Formula Allocation and Maximum Capacity

		1988			1993			1998			2003		
		Elevation	Differences		Elevation	Differences		Elevation	Differences		Elevation	Differences	
Month	Project	Existing	P3	AD	Existing	P3	AD	Existing	P3	AD	Existing	P3	AD
September	Albeni Falls	2060.9	-	-	2060.8	-	-	2060.8	-	-	2061.0	-	-0.1
	Dworshak	1575.8	-2.7	-0.7	1568.5	-3.4	-1.2	1567.5	-2.8	-2.4	1571.7	-0.5	-1.5
	Grand Coulee	1288.3	-0.1	-	1288.0	-	-	1288.0	-	-	1288.3	-	-0.1
	Hungry Horse	3546.1	-5.0	-1.3	3532.7	-4.6	-2.2	3530.6	-4.0	-3.6	3537.1	-0.8	-2.2
	Libby	2455.3	-1.0	-	2451.7	-2.1	-0.7	2451.2	-1.6	-1.3	2453.2	-	-0.7
October	Albeni Falls	2057.4	-	-	2057.2	0.2	-	2057.4	-	-	2057.5	-	-0.1
	Dworshak	1571.9	-2.8	-0.7	1564.9	-3.0	-1.2	1564.2	-2.8	-2.6	1568.0	-0.6	-1.6
	Grand Coulee	1288.2	-	-	1288.0	0.2	-	1288.1	-	-	1288.3	-	-
	Hungry Horse	3537.0	-5.7	-1.6	3524.1	-4.2	-2.0	3522.9	-4.1	-4.1	3529.0	-1.2	-2.9
	Libby	2448.1	-1.9	2.4	2447.3	-2.5	-0.9	2447.4	-2.1	-2.1	2449.2	-0.9	-1.5
November	Albeni Falls	2052.6	-	-	2052.6	-	-	2052.6	-	-	2052.6	-	-
	Dworshak	1557.5	-1.7	-	1553.4	-1.3	-	1553.8	-1.6	-1.6	1555.4	-	-1.0
	Grand Coulee	1288.2	-	-	1288.3	-	-	1288.2	-	-	1288.4	0.2	-
	Hungry Horse	3536.1	-5.6	-1.4	3523.3	-4.1	-1.9	3522.7	-3.8	-4.1	3528.1	-1.0	-3.0
	Libby	2435.9	1.0	4.1	2437.8	-	0.7	2438.2	-	-1.1	2439.4	0.8	-0.7
December	Albeni Falls	2052.8	-	0.1	2053.2	0.2	-	2053.3	0.3	-	2053.1	0.3	-
	Dworshak	1546.3	2.9	5.2	1549.5	-	-	1549.5	-	-0.9	1550.0	0.8	-0.3
	Grand Coulee	1287.2	-	-	1287.5	0.2	-	1287.6	0.2	-	1287.4	0.3	-
	Hungry Horse	3525.2	-4.4	-	3516.2	-2.6	-	3515.5	-	-3.2	3519.9	1.5	-2.4
	Libby	2400.9	2.6	6.7	2406.7	-	1.2	2406.9	0.5	-0.4	2407.7	0.9	-
January	Albeni Falls	2054.2	0.3	0.7	2055.0	-	-	2055.3	0.2	0.1	2055.0	0.2	-
	Dworshak	1526.2	2.7	4.3	1527.0	-	1.1	1528.1	0.4	-0.5	1527.0	1.3	-
	Grand Coulee	1275.3	0.9	2.2	1278.3	-	0.4	1278.7	0.6	0.6	1278.4	0.8	-
	Hungry Horse	3508.8	-	4.4	3504.5	-1.7	-	3504.0	-	-1.4	3506.2	2.2	-1.1
	Libby	2365.8	3.2	6.8	2371.1	0.7	1.8	2367.9	1.3	-	2371.4	1.7	-
February	Albeni Falls	2054.9	0.1	0.4	2055.2	-	-	2055.7	0.1	0.1	2055.4	0.1	-
	Dworshak	1504.2	2.3	3.5	1504.9	-	1.3	1506.3	1.0	-0.2	1504.0	1.5	-
	Grand Coulee	1258.2	0.5	2.2	1261.4	-	0.5	1262.8	0.8	0.6	1261.9	0.9	0.1
	Hungry Horse	3496.9	-	3.3	3490.9	-	1.1	3490.5	-	-0.8	3491.6	2.1	-0.8
	Libby	2340.1	2.3	3.9	2342.8	-	1.5	2336.3	1.5	-	2341.5	2.1	-
March	Albeni Falls	2055.6	-	-	2055.6	-	-	2055.6	-	-	2055.6	-	-
	Dworshak	1477.4	1.1	1.4	1477.7	-	0.8	1479.4	0.7	-	1476.2	0.9	-
	Grand Coulee	1235.9	-	0.7	1236.7	-	0.5	1237.4	1.2	0.6	1236.3	1.5	-
	Hungry Horse	3485.1	-	1.8	3477.2	-	1.4	3476.7	-	-	3477.8	2.3	0.5
	Libby	2333.5	2.2	3.4	2335.0	-	1.6	2327.9	1.5	-	2334.2	2.3	-0.6

Table 4.2.8d (Continued)

Month	Project	1988 Elevation Existing	1988 Differences P3	1988 Differences AD	1993 Elevation Existing	1993 Differences P3	1993 Differences AD	1998 Elevation Existing	1998 Differences P3	1998 Differences AD	2003 Elevation Existing	2003 Differences P3	2003 Differences AD
April 1-15	Albeni Falls	2055.5	-	-	2055.4	-	-	2055.5	-	-	2055.5	-	-
	Dworshak	1487.6	0.9	1.1	1487.1	-	0.5	1490.5	0.9	-	1485.8	0.9	-
	Grand Coulee	1234.6	-0.4	0.5	1234.1	-	0.7	1233.8	1.6	0.8	1233.4	1.5	0.4
	Hungry Horse	3486.7	-	1.8	3478.4	-	1.3	3478.4	-	-	3480.1	2.4	-0.6
	Libby	2335.8	2.2	3.5	2336.4	-	1.6	2330.2	1.6	-	2336.5	2.6	-
April 16-30	Albeni Falls	2055.4	-	-	2055.1	-	-	2055.5	-	-	2055.2	-	-
	Dworshak	1506.1	0.8	1.0	1505.5	-	0.4	1509.5	0.9	-0.2	1503.9	0.9	-
	Grand Coulee	1232.1	-	-	1231.5	-	0.5	1230.8	1.1	0.2	1231.3	1.2	0.3
	Hungry Horse	3493.2	-	-	3484.7	-	1.2	3483.6	1.1	-	3485.8	2.1	-0.5
	Libby	2344.7	2.1	3.2	2344.7	-	1.5	2339.4	1.5	-	2344.7	2.5	-
May	Albeni Falls	2062.5	-	-	2062.4	-	-	2062.5	-	-	2062.4	-	-
	Dworshak	1560.1	0.8	1.0	1559.6	-	0.4	1559.8	0.9	-	1557.5	0.9	0.3
	Grand Coulee	1254.2	-	-	1252.3	-	0.5	1252.4	0.9	0.1	1250.9	1.3	-0.4
	Hungry Horse	3525.6	-	-	3520.3	-	0.8	3520.4	0.7	-	3519.5	1.6	-
	Libby	2397.4	1.3	1.7	2397.0	-	0.9	2396.0	0.9	-	2395.1	1.7	-
June	Albeni Falls	2062.6	-	-	2062.7	-	-	2062.6	-	-	2062.6	-	-
	Dworshak	1591.3	0.7	0.8	1589.6	-0.5	0.3	1588.7	1.0	-	1588.8	0.9	0.1
	Grand Coulee	1286.9	-0.1	-0.1	1286.6	-0.2	-	1286.2	0.2	-	1285.5	0.3	-
	Hungry Horse	3552.0	-	-	3546.3	-0.8	0.6	3546.4	1.1	-	3546.5	1.4	-
	Libby	2445.9	0.6	0.8	2444.0	-	-	2444.6	0.6	-	2444.2	1.0	-
July	Albeni Falls	2062.5	-	-	2062.5	-	-	2062.5	-	-	2062.5	-	-
	Dworshak	1593.4	-0.4	0.5	1590.2	-1.4	-	1588.6	1.0	-0.1	1589.4	-	-
	Grand Coulee	1290.0	-	-	1290.0	-	-	1289.9	-	-	1289.9	-	-
	Hungry Horse	3554.1	-	-	3547.0	-1.2	-	3546.1	1.6	-	3547.0	1.2	-
	Libby	2455.5	0.6	0.8	2453.7	-	0.6	2453.6	0.6	-	2453.6	0.4	-
August 1-15	Albeni Falls	2062.5	-	-	2062.5	-	-	2062.5	-	-	2062.5	-	-
	Dworshak	1592.5	-0.3	-	1588.0	-1.8	-0.3	1586.5	1.0	-0.4	1587.0	0.4	-0.3
	Grand Coulee	1290.0	-	-	1290.0	-	-	1289.9	-	-	1289.9	-	-
	Hungry Horse	3553.4	-1.1	-1.1	3544.7	-2.0	-	3543.6	1.6	-	3543.9	1.1	-0.3
	Libby	2455.5	0.5	0.6	2453.3	-0.5	0.4	2453.1	0.6	-0.2	2452.8	0.4	-0.3
August 16-31	Albeni Falls	2062.5	-	-	2062.5	-	-	2062.5	-	-	2062.5	-	-
	Dworshak	1591.3	-0.7	-0.5	1585.3	-2.0	-0.5	1584.3	1.0	-0.5	1584.5	0.4	-0.5
	Grand Coulee	1290.0	-	-	1290.0	-	-	1289.9	-	-	1290.0	-	-
	Hungry Horse	3552.4	-1.8	-1.7	3542.4	-3.0	-	3541.3	1.5	-0.7	3540.9	1.0	-0.9
	Libby	2455.5	0.4	0.5	2453.2	-0.7	0.3	2452.9	0.6	-0.3	2452.6	0.4	-0.4

Existing = Existing Contracts
P3 = Assured Delivery Alternative 3
AD = Assured Delivery
- Indicates a difference which is not statistically significant or is less than 0.1 ft.
- A negative number indicates a lower elevation than the base condition.

(VS6-PG-1872Z)

4.2.2 RECREATION, IRRIGATION, AND CULTURAL RESOURCES

OVERVIEW AND SUMMARY

Recreation, irrigation, cultural resources, and resident fish may be affected by the operation of Federal storage reservoirs. The effects of Intertie decisions on reservoir levels are discussed in Section 4.2.1. Potential effects of Intertie decisions on resident fish are addressed in Section 4.2.3. Sections 4.2.2.1 through 4.2.2.3 discuss the effects of Intertie decisions on recreation, irrigation, and cultural resources, respectively. Section 4.2.2.4 presents the results of sensitivity analyses identified as having potentially significant impacts. Mitigation is discussed in Section 4.2.2.5.

Intertie decisions are unlikely to affect recreation or irrigation in the Pacific Northwest. Reservoir levels during the summer months on which recreation depends are only minimally affected by any of the alternatives. During the fall and winter months however, firm marketing may change reservoir levels thus potentially affecting cultural resources. Erosion of cultural resource sites at Libby could be a particular problem resulting from firm marketing.

4.2.2.1 Recreation

Introduction/Methods of Analysis

Federal hydro projects provide numerous opportunities for recreation both in the reservoirs themselves and in the areas downstream from the projects. Typically associated with the projects are water-related activities such as boating, swimming, water skiing, and fishing. In conjunction with these activities are other outdoor recreation opportunities including camping, picnicking, sightseeing, hiking, and other related activities.

Because many recreation activities are influenced by the project's reservoir elevation or downstream flows, reservoir operations which occur within the bounds specified by the project owners/operators may influence the amount, type, and quality of recreation experiences. Changes in reservoir elevation or, to a lesser extent, project discharge resulting from Intertie decisions may result in impacts to recreation. In general, elevation changes would affect recreation in the reservoir while discharge changes would influence downstream recreation.

Maintaining reservoirs at full pool is most advantageous for recreation. Recreational facilities such as boat ramps, dock, and swimming areas are typically designed for optimal use at full pool. In addition, most reservoirs have the appearance of a natural lake when full, creating an appealing environment for recreation.

Downstream recreational activities such as fishing, swimming, rafting, and boating are influenced by project discharge. Marked short-term changes in project discharge generally reduce fish activity and consequently impact fishing success. Rapid flow changes also present a safety hazard to downstream water users. At most projects, constraints have been developed limiting the rate of change in project discharge to protect downstream parties (see Corps of Engineers, 1985). In addition, when possible, reservoir discharges are held constant and within ranges appropriate to enhance downstream fishing success during peak fishing periods. Requests for special operations at projects (including Libby, Albeni Falls, Hungry Horse, Grand Coulee, and Dworshak) to benefit nonpower uses including recreation and fishing are made by the COE and BOR.

Potential impacts of Intertie decisions were assessed using data from the SAM studies. In order to determine and compare potential impacts of Intertie decisions on recreation at Federal storage reservoirs, a method of converting SAM output (reservoir elevations) to recreation impact was needed. Because most recreation at the projects of concern occurs during summer months, the recreation analysis was confined to the May through August period.

A method was developed based on available data relating recreation sites or usage to reservoir elevations for the reservoirs studied. For Grand Coulee and Hungry Horse, an impact index was developed which related the number of available boat ramps to the reservoir elevation for a given simulation, month, year, and alternative. The number of available boat ramps (based on reservoir elevation data) was determined for each simulation on a monthly basis. This number was then averaged over all 200 simulations and presented as a percentage of the total number of existing ramps. These values then represent the average number of boat ramps available expressed as a percentage of the total number of existing boat ramps for a given alternative. A seasonal average index was also calculated for the May through August period. A list of boat ramps used in the analysis and their minimum usable elevations is contained in Appendix C, Part 4.

For Libby and Dworshak reservoirs, visitor-use indices were obtained from the Corps of Engineers. The visitor indices indicate how decreases in reservoir elevation below full pool would be expected to affect visitor usage as a percentage of usage at full pool. These indices were then applied to the changes in reservoir elevation associated with Intertie decisions to obtain an estimate of impact on visitor use. Indices were developed on a monthly basis for the May through August period. A seasonal average index was also calculated. No indices were developed for Albeni Falls because summer reservoir levels did not change for any of the alternatives. Data used for the analysis is provided in Appendix C, Part 4.

The Kokanee and Kamloops Fishing Derby at Albeni Falls reservoir is an important recreation event which occurs outside the normal summer recreation season. This event is held in conjunction with the opening of fishing season around May 1. The success of the event is enhanced by reservoir levels of at least 2,054 feet. SAM end-of-April reservoir elevation data were used to determine the probability of being at or above the desired elevation for this event.

Recreation downstream of reservoirs is also important; however, it is more difficult to assess potential impacts in this area because effects are primarily related to short-term fluctuations in flow. The SAM provides flow information on a monthly average basis. However, this information is not particularly useful in determining short-term flow changes. Because such short-term changes are highly dependent on specific, often short-term, operational constraints and conditions, these changes are not amenable to analysis using the SAM. Constraints have been developed at most projects which limit the rate of change in discharge. In some cases, short-term requirements are used to maintain flows at levels suitable for recreation use, particularly fishing. All projects will continue to be operated within existing constraints. As discussed in Section 4.2.1, operations at Libby, Hungry Horse, Albeni Falls, and Dworshak should be minimally affected. A brief discussion of potential short-term elevation changes at Grand Coulee and short-term flow changes in the Columbia River river downstream of Grand Coulee is contained in Section 4.2.1.

Effects of Increasing Intertie Capacity

As discussed in Section 4.2.1, increasing Intertie capacity has little effect on reservoir elevations. This is particularly true during the summer recreation season. As shown in Table 4.2.9, differences in seasonal recreation indices at Libby resulting from Intertie expansions are on the order of 0.1 percent (Tables may be found following page 4.2.2-9). Results are similar for other reservoirs. Monthly recreation indices are also minimally affected by Intertie expansions. Maximum changes are less than 1 percent at all reservoirs studied. Data for Libby are presented in Table 4.2.10 and are illustrative of results for other reservoirs. Recreation indices for Hungry Horse, Grand Coulee, and Dworshak may be found in Appendix C, Part 4.

The probability of meeting the desired elevation for the Kokanee and Kamloops Derby at Albeni Falls is high for all alternatives studied and is greater than 90 percent in all cases (Appendix C, Part 4). Intertie capacity had no effect on this parameter.

Changes in downstream flows resulting from Intertie expansions are not expected to have significant effects on recreation. Most of the additional hydro energy generated as a result of Intertie development is derived from conversion of spill at downstream projects. This results in increased generation with no change in flow. If energy is shaped into daytime hours to maximize revenues without increasing total sales, increases in Columbia River flows, of approximately 15 kcfs could occur with the DC Upgrade, for example (Section 4.2.1). This magnitude of change is relatively small compared to the normal daily flow fluctuations at downstream projects which may be 80-100 kcfs or more. Limitations on the hourly rate of change in discharge have been established by the COE at The Dalles and John Dam dams (as examples) which are based on a change in elevation downstream of the dam of 3 feet per hour. This equates to a change in discharge of 150 kcfs and 200 kcfs per hour at The Dalles and John Day dams, respectively. The discharge changes which could occur as a result of Intertie expansions are well within the established limits and are small relative to normal daily fluctuations.

Effects of Formula Allocation Options

Formula allocation options have little effect on summer reservoir levels (see Section 4.2.1) and thus little potential impact on recreation. Seasonal and monthly recreation indices for Libby are presented in Tables 4.2.9 and 4.2.11, respectively. Again, differences between alternatives are typically less than 1 percent for all months and reservoirs. Formula allocation alternatives have little effect on the end-of-April Albeni Falls elevation. Data for Hungry Horse, Grand Coulee, and Dworshak are provided in Appendix C, Part 4.

As discussed in Section 4.2.1, formula allocation is not expected to affect downstream flows for recreation.

Effects of Long-Term Firm Marketing

Reservoir levels during the recreation season are only slightly affected by firm marketing alternatives (see Section 4.2.1). As a result, firm marketing has little effect on recreation indices. Results for Libby are presented in Tables 4.2.9 and 4.2.12. Data for other reservoirs are presented in Appendix C, Part 4. Effects of firm contracts are slightly greater at Hungry Horse and Dworshak than for either Intertie capacity or formula allocation alternatives. Maximum differences of up to 2 or 3 percent occur in the monthly indices at Hungry Horse, the most affected project. Potential impacts of that magnitude occur in only a few cases and are considered relatively minor.

Firm marketing had essentially no effect on the probability of being above 2,054 feet at Albeni Falls for the Kokanee and Kamloops Derby.

As discussed in Section 4.2.1, firm contract alternatives have the potential to increase downstream flow fluctuations. Increased peaking deliveries of 2550 MW would increase daytime flows by approximately 30 kcfs over the Existing Contract alternative if it were all generated on the hydro system. This amount of change is typical of normal operations and is well within established constraints at lower Columbia River projects. No significant effects on downstream recreation are expected as a result of firm contracts.

4.2.2.2 Effects on Irrigation

Introduction/Method of Analysis

Levels of allowable irrigation withdrawals are determined by the individual states and are established water rights. Hydro operation planning is developed around flows that include irrigation withdrawals. In most areas of the Columbia River Basin, river operations affect irrigation only to the extent that coordination is sometimes necessary to allow irrigators to move their pump intakes in response to changes in reservoir or river levels. These types of impacts would not be changed by Intertie capacity or policy decisions. However, at Grand Coulee, pumps for the Columbia Basin Project are located at the plant. As reservoir levels drop, pumping becomes more difficult; at some levels, pumps will not operate or may be damaged if run. There is currently a requirement for the reservoir to be at or above 1,240 feet at the end of May for irrigation. If that constraint is not met, there would be some potential for drawdown of Banks Lake, which would have an adverse effect on the fishery and recreation.

The streamflows used in SAM have been adjusted for irrigation depletion. It is assumed that irrigation depletions will change over time; however, the models used in this analysis do not have the ability to do this. As an assumption, the 1991 level of estimated irrigation depletion was used in these studies. Consequently, irrigation depletions are probably slightly over estimated in the near term and under estimated in the later years. Because all alternatives are affected equally, an error in the irrigation assumptions does not affect incremental results of alternative comparisons.

To assess the potential impact of various Intertie alternatives on irrigation, the results of the SAM hydro studies discussed in Section 4.2.1 were used. The results were converted to give the probability of being at or above 1,240 feet at the end of May at Grand Coulee (Appendix C, Part 5). As discussed in Chapter 3, there are many uncertainties involved in determining the amount of future irrigation withdrawal for the Columbia Basin Project. Approximately half of the authorized acreage has been developed and permits for the remaining portion are up for renewal in 1989. The Bureau of Reclamation is assessing several proposals for continued development of the Columbia Basin Project. The maximum impact these proposals would have on regional firm power during the 20-year study horizon for this EIS is 50-100 MW. This difference would affect all policy and capacity alternatives studied. This would not affect the relationship between alternatives. For these reasons, only the current level of Columbia Basin Project development is assumed for environmental analysis in this EIS. An estimate was made of the potential effect Columbia Basin development would have on the economics of Intertie development. In order to assess this economic aspect of the Columbia Basin Project, SAM studies were performed using Proposed Formula Allocation and Assured Delivery contracts while varying the Intertie size. Surplus firm energy was reduced or resources added to make up for the increased firm load associated with the irrigation expansion.

Effects of Increasing Capacity, Formula Allocation, and Long-Term Firm Marketing

There are no differences between alternatives in the probability of meeting the 1,240 foot criterion for irrigation at Grand Coulee. Those years in which the end-of-May elevation at Grand Coulee is below 1,240 feet reflect flood control requirements. Data for all alternatives are provided in Appendix C, Part 5.

Expansion of the Columbia Basin project would reduce benefits of Intertie expansions. Benefits of the DC Upgrade would be reduced by about $3.6 million and benefits of Maximum Intertie development would be reduced by about $17 million (present worth values in 1987 dollars). These reductions are small relative to the total benefits of Intertie expansion. (See Section 4.5.)

4.2.2.3 Cultural Resources

Introduction/Methods of Analysis

Cultural resources are defined as "the nonrenewable evidence of human occupation or activity as reflected in any district, site, building, structure, artifact, ruin, object, work of art, architecture, or natural feature that was important in human history at the national, state, or local level." Cultural resources have been identified at each of the five Federal storage reservoirs potentially impacted by changes in hydro system operations.

Cultural resources located in and around Federal storage reservoirs in the PNW have been affected by numerous activities including inundation, logging, agriculture, wave and wind erosion, off road vehicle use, relic collecting, and vandalism. Within the current operating regime, changes in reservoir elevations can affect cultural resources in two ways: by changing the rate of erosion of cultural resource sites and by changing their accessibility to vandals and relic collectors. Repeated wetting and drying of organic artifacts causes artifact deterioration. It is probable that some organic artifacts within the existing zone of pool fluctuation have already been adversely affected by this process (Lenihan et al. 1981).

Relic collecting and vandalism usually occur during the warmer months and require site accessibility. These activities are facilitated by increased erosion, weather, and pool fluctuations. Relic hunters often key activities to high-erosion conditions such as rapid and repeated drawdowns and increased storm conditions which expose more artifacts.

Two measures were developed to estimate the effect of various Intertie actions on cultural resources. The first addresses changes in erosion potential of sites while the second quantifies the accessibility of sites for vandalism and relic collection.

Because of limited cultural resources data for Hungry Horse and Dworshak reservoirs, a quantitative assessment of impacts was not done for these projects. In order to assess the magnitude of potential impacts of Intertie decisions at the remaining reservoirs, SAM data on predicted reservoir elevations were used, along with available data on location (elevation) of cultural resource sites, to develop wave erosion and site accessibility indices. Only those sites located within the operating range of each reservoir were considered.

For each reservoir, cultural resource sites with known elevations were grouped in 10-foot increments. Next, the SAM results were grouped into the same 10-foot elevation increments. A wave erosion index was then calculated for each reservoir, month, and study year by multiplying the number of sites in a given elevation range by the number of simulations in which reservoir elevations fell within that elevation range, and totaling the results for all simulations. This is a measure of the coincidence of sites with reservoir elevations. Similarly, a site accessibility index was developed in which the number of accessible sites (sites which are higher in elevation than the reservoir level) were totaled for all simulations. Results were then presented as a percentage change from a base case. Information on sites used in the analysis and a sample calculation of wave erosion and site accessibility indices are provided in Appendix C, Part 6.

Effects of Increasing Intertie Capacity

Annual average wave erosion and site accessibility indices are presented in Table 4.2.13. Changes in Intertie capacity had essentially no effect on cultural resource indices. An inspection of monthly data (Appendix C, Part 6) indicates that changes in monthly indices are relatively minor also. These results are consistent with the fact that reservoir elevations do not change substantially as a result of Intertie expansions.

Effects of Formula Allocation Options

Analysis for the current studies does not show substantial potential impacts resulting from either the Proposed Formula Allocation or the Hydro-First option. This is expected from the hydro system data because reservoir elevations are not markedly affected by the formula allocation alternatives. Except in a few months in 1988 when differences are as much as about 10 percent at Libby, changes in the impact indices are generally less than 5 percent when compared to the Pre-IAP alternative (Table 4.2.14 and Appendix C, Part 6).

Effects of Long Term Firm Contracts

Current study results indicate potential impacts could result from firm marketing in the earliest year studied, 1988. Typically, changes resulting from Assured Delivery cases are somewhat larger than for Federal Marketing cases; however, the effects of both alternatives are similar. Increases in annual average indices for Libby in 1988 are up to 12 percent for wave erosion with a corresponding decrease of 6 percent or so in site accessibility (Table 4.2.15). Increases in the monthly wave erosion index of up to 40 percent at Libby occur as a result of firm marketing actions in 1988. These increases are accompanied by decreases in the monthly site accessibility index of up to 15-20 percent. Results for 1993 also indicate potential impacts, depending on the time of year; however, the magnitude is less with maximum changes being in the 10-20 percent range. In general, major effects are confined to the Libby project in the first 2 years studied (see Tables 4.2.13 to 4.2.15). (Monthly data can be found in Appendix C, Part 6.)

An inspection of data used in the calculation of wave erosion indices shows that at Libby a number of cultural resource sites are located in the higher areas of the reservoir. A shift in the number of occurrences of reservoir elevations in these areas results in a large change in the wave erosion index. A sample of this type of calculation is provided in Appendix C, Part 6. The data indicate that increased erosion of cultural resource sites at Libby is a potential problem with the Federal Marketing and Assured Delivery marketing alternatives in 1988. It is also possible that there would not be problems under the actual water conditions, loads, and marketing conditions that occur in that year. In any case, Libby will continue to be operated according to project constraints used in Coordination Agreement planning and provided by the Corps of Engineers. (See also Section 4.2.1.)

4.2.2.4 Sensitivity and Other Analyses

Alternative firm marketing cases (Assured Delivery Alternatives 1, 2, and 3) are the only sensitivity studies identified in Section 4.2.1.5 as having potential effects on summer reservoir levels and thus recreation. Mean reservoir elevations at Hungry Horse and Dworshak are generally lower in July and August of 1988 and 1993 than with Existing Contracts. Higher reservoir levels occur in 1998 and 2003 as a result of these marketing alternatives (Appendix C, Part 2).

Based on these results, recreation indices were calculated for Assured Delivery Alternatives 1 and 2 which bracket the range of effects of the alternative marketing cases. Data for Libby are given in Tables 4.2.9 and 4.2.12. Data are presented for Hungry Horse and Dworshak in this discussion and further information may be found in Appendix C, Part 4. Seasonal recreation indices for Hungry Horse in 1988 are lower than for Existing Contract cases by about 1 percent. In 1993, differences are slightly less than 1 percent. As expected from the reservoir elevation data, recreation indices in 1998 and 2003 are slightly higher for the Assured Delivery Alternatives 1 and 2 than for the Existing Contracts alternative. Maximum decreases in monthly indices due to Alternative marketing occur in August of 1988 and are about 3 percent. These changes are similar in magnitude to those observed for Assured Delivery and Federal Marketing alternatives.

At Dworshak, changes in seasonal recreation indices are small--typically 0 to 0.3 percent. In 1993 the indices are lower with Alternatives 1 and 2 marketing while in 1998 and 2003 indices for Alternatives 1 and 2 are higher than for the Existing Contract cases. Decreases in monthly recreation indices are less than 1 percent with one exception of a decrease of 1.6 percent. As with Hungry Horse, increased indices relative to Existing Contracts occur in 1998 and 2003. These changes are relatively small and would not significantly affect recreation.

Two parameters are identified in Section 4.2.1.5 as having the potential for impacts to cultural resources. These are the effects of increasing Intertie capacity assuming low PNW loads and the effects of additional firm contract alternatives.

When low Northwest loads are assumed, increasing the Intertie to Maximum capacity results in lower reservoir elevations particularly in the winter months. This generally reduces wave erosion and increases site accessibility. At Grand Coulee, wave erosion is decreased by as much as 20 percent. Increases in wave erosion are noted at Albeni Falls of up to 6 or 7 percent. Site accessibility increased for all projects, particularly Albeni Falls.

Results for alternative firm contracts are similar to results obtained for Assured Delivery and Federal Marketing options (see Table 4.2.15 and Appendix C, Part 6). Wave erosion at Libby increased by approximately 20 to 30 percent over the Existing Contract Levels for some winter months, but by an average of less than 10 percent annually. At Grand Coulee, wave erosion increases by less than 1 percent annually, although in some months increases of 10 percent occur. The results are somewhat different than the Assured Delivery and Federal Marketing cases in that this effect occurs in all 4 years studied rather than being noticeable only in the early years. As expected, site accessibility declined by modest amounts for all projects in the additional firm marketing cases.

4.2.2.5 Procedure for Mitigating Potential Impacts

It is possible that changes in reservoir elevations caused by Intertie decisions could adversely affect properties listed in or eligible for the National Register of Historic Places at Grand Coulee, Dworshak, Albeni Falls, Libby, and Hungry Horse reservoirs. Of these, only at Libby have cultural resources been fully surveyed and evaluated, and a mitigation plan developed. BPA is consulting with the Bureau of Reclamation, the Corps of Engineers, the Advisory Council on Historic Preservation, the National Park Service, affected Indian tribes, the Bureau of Indian Affairs, and the Washington, Idaho, and Montana State Historic Preservation Officers to develop a Programmatic Memorandum of Agreement (PMOA). This PMOA will provide for full satisfaction of BPA's obligation under the National Historic Preservation Act. See Section 4.6 for more information about the Programmatic Agreement.

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Table 4.2.9

SEASONAL RECREATION INOEX FOR LIBBY
Expected Usage as a Percentage of Full Pool Use

	1988 EX	1988 DC	1988 AC	1988 MX	1993 EX	1993 DC	1993 AC	1993 MX
EXISTING CONTRACT LEVEL								
PF	87.6	-	-	-	86.8	-	-	-
PR	87.7	87.7	-	87.7	86.8	86.8	-	86.9
HF	87.7	-	-	-	86.8	-	-	-
FEOERAL MARKETING								
PF	87.8	-	-	87.8	87.0	-	-	87.0
PR	87.9	87.9	-	87.9	87.0	87.0	-	87.0
HF	87.8	-	-	87.8	87.0	-	-	87.0
ASSURED OELIVERY								
PF	87.9	-	-	87.9	87.0	-	-	87.0
PR	88.1	88.1	88.1	88.1	87.0	87.0	87.1	87.0
HF	88.0	-	-	88.0	87.0	-	-	87.0
ASSURED DELIVERY ALTERNATIVE 1								
PR	88.0	88.0	-	-	86.9	86.9	-	-
ASSURED DELIVERY ALTERNATIVE 2								
PR	-	-	-	87.8	-	-	-	86.8
ASSURED DELIVERY ALTERNATIVE 3								
PR	-	88.0	-	88.0	-	86.8	-	86.8

	1988 EX	1988 DC	1988 AC	1988 MX	1993 EX	1993 DC	1993 AC	1993 MX
EXISTING CONTRACT LEVEL								
PF	87.1	-	-	-	86.7	-	-	-
PR	87.1	87.0	-	87.0	86.7	86.7	-	86.8
HF	87.1	-	-	-	86.8	-	-	-
FEDERAL MARKETING								
PF	87.0	-	-	87.0	86.7	-	-	86.6
PR	87.0	87.0	-	87.0	86.6	86.6	-	86.6
HF	87.0	-	-	87.0	86.6	-	-	86.6
ASSURED DELIVERY								
PF	87.0	-	-	87.0	86.7	-	-	86.7
PR	87.0	87.0	87.0	87.0	86.7	86.7	86.6	86.6
HF	87.0	-	-	87.0	86.7	-	-	86.7
ASSURED DELIVERY ALTERNATIVE 1								
PR	87.2	87.2	-	-	87.1	87.0	-	-
ASSURED DELIVERY ALTERNATIVE 2								
PR	-	-	-	87.2	-	-	-	87.0
ASSURED DELIVERY ALTERNATIVE 3								
PR	-	87.2	-	87.2	-	87.0	-	87.0

- = Case not run
PF = Pre IAP
PR = Proposed Policy
HF = Hydro First
EX = Existing Intertie
DC = DC Upgrade
AC = Third AC
MX = Maximum Capacity

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Table 4.2.10

EFFECTS OF INTERTIE CAPACITY ON RECREATION INDICES AT LIBBY
Expected Usage as a Percentage of Full Pool Use
Assuming Proposed Formula Allocation and Assured Delivery

	May	June	July	Aug 1-15	Aug 16-31
Existing Intertie					
1988	68.8	88.8	97.4	97.5	97.5
1993	68.7	87.7	96.1	95.7	95.5
1998	68.4	88.0	96.0	95.6	95.4
2003	68.4	87.4	95.9	95.2	94.9
DC Expansion					
1988	68.8	88.8	97.4	97.5	97.5
1993	68.7	87.7	96.1	95.7	95.5
1998	68.4	88.0	96.0	95.6	95.4
2003	68.4	87.4	95.8	95.2	94.9
Third AC					
1988	68.8	88.8	97.4	97.5	97.5
1993	68.7	87.8	96.1	95.8	95.5
1998	68.4	88.1	96.0	95.6	95.4
2003	68.4	87.3	95.8	95.2	94.9
Maximum Intertie					
1988	68.8	88.8	97.4	97.5	97.5
1993	68.7	87.8	96.1	95.7	95.5
1998	68.4	88.2	96.0	95.6	95.4
2003	68.4	87.3	95.8	95.2	94.9

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Table 4.2.11

EFFECTS OF FORMULA ALLOCATION ON RECREATION INDICES AT LIBBY
Expected Usage as a Percentage of Full Pool Use
Assuming Existing Capacity and Existing Contracts

	May	June	July	Aug 1-15	Aug 16-31
Pre-IAP					
1988	68.4	88.4	96.9	96.9	96.9
1993	68.6	87.4	95.8	95.6	95.4
1998	68.4	88.1	96.1	95.8	95.5
2003	68.4	87.4	95.9	95.5	95.1
Proposed Policy					
1988	68.4	88.6	96.9	96.9	96.9
1993	68.6	87.4	95.8	95.6	95.4
1998	68.4	88.1	96.1	95.8	95.5
2003	68.4	87.4	95.9	95.5	95.1
Hydro First					
1988	68.4	88.3	96.9	97.0	97.1
1993	68.6	87.4	95.8	95.5	95.3
1998	68.4	88.1	96.1	95.8	95.5
2003	68.4	87.4	95.9	95.5	95.2

(VS6-PG-1318I)

Table 4.2.12

EFFECTS OF LONG-TERM FIRM CONTRACTS ON RECREATION INDICES AT LIBBY
Expected Usage as a Percentage of Full Pool Use
Assuming Proposed Formula Allocation and Maximum Capacity

	May	June	July	Aug 1-15	Aug 16-31
Existing Contracts					
1988	68.4	88.6	96.9	96.9	96.9
1993	68.6	87.6	95.8	95.6	95.3
1998	68.4	88.1	96.0	95.8	95.5
2003	68.4	87.4	95.9	95.5	95.2
Federal Marketing					
1988	68.6	88.7	97.2	97.3	97.3
1993	68.7	87.6	96.1	95.8	95.6
1998	68.4	88.2	96.0	95.6	95.4
2003	68.4	87.2	95.8	95.2	94.8
Assured Delivery					
1988	68.8	88.8	97.4	97.5	97.5
1993	68.7	87.8	96.1	95.7	95.5
1998	68.4	88.2	96.0	95.6	95.4
2003	68.4	87.3	95.8	95.2	94.9
Assured Delivery Alternative 2					
1988	68.5	88.7	97.1	97.1	97.0
1993	68.7	87.7	95.8	95.2	94.9
1998	68.5	88.5	96.2	95.9	95.7
2003	68.8	87.9	96.1	95.6	95.2
Assured Delivery Alternative 3					
1988	68.7	88.8	97.3	97.3	97.3
1993	68.7	87.7	95.8	95.3	95.0
1998	68.5	88.4	96.2	96.0	95.7
2003	68.7	87.8	96.0	95.5	95.3

(VS6-PG-1318I)

Table 4.2.13

EFFECTS OF INTERTIE CAPACITY ON
WAVE EROSION AND SITE ACCESSIBILITY
(Percent Change From Existing Intertie Case)

Assuming Proposed Formula Allocation

		Wave Erosion			Site Accessibility		
		DC Upgrade	Third AC	Maximum	DC Upgrade	Third AC	Maximum
Existing Contract Level							
1993	Libby	0.1	- 1/	0.0	0.1	-	-0.2
	Albeni Falls	-0.1	-	-0.1	-0.2	-	-0.3
	Grand Coulee	0.1	-	0.2	-0.3	-	-0.4
1998	Libby	0.0	-	0.0	0.1	-	0.1
	Albeni Falls	-0.2	-	0.1	-1.0	-	0.5
	Grand Coulee	0.3	-	-0.1	-0.5	-	0.2
2003	Libby	0.0	-	-0.1	0.0	-	0.0
	Albeni Falls	0.1	-	0.2	0.4	-	0.7
	Grand Coulee	-0.1	-	-0.1	0.2	-	0.2
Assured Delivery Contracts							
1993	Libby	0.0	0.0	0.1	0.0	0.0	0.0
	Albeni Falls	0.0	-0.1	0.0	-0.1	-0.3	-0.2
	Grand Coulee	0.0	0.1	0.1	-0.1	-0.3	-0.3
1998	Libby	0.0	0.1	0.0	0.1	0.1	0.3
	Albeni Falls	0.0	-0.2	-0.2	0.1	-0.7	-1.0
	Grand Coulee	0.0	0.2	0.3	0.1	-0.3	-0.5
2003	Libby	-0.1	-0.2	-0.3	0.1	0.2	0.2
	Albeni Falls	0.1	0.2	0.3	0.5	0.8	1.0
	Grand Coulee	-0.1	-0.2	-0.1	0.2	0.2	0.2

1/ - Indicates the case was not run.

(VS6-PG-1318I)

Table 4.2.14

EFFECTS OF FORMULA ALLOCATION ON
WAVE EROSION AND SITE ACCESSIBILITY INDICES
(Percent Change From Pre-IAP Condition)

		Wave Erosion		Site Accessibility	
		Proposed	Hydro-First	Proposed	Hydro-First
EXISTING INTERTIE Existing Contract Level					
1988	Libby	0.8	-1.6	-0.2	0.7
	Albeni Falls	0.0	0.1	-0.1	0.3
	Grand Coulee	0.2	-0.2	-0.3	0.4
1993	Libby	0.0	0.0	0.0	0.2
	Albeni Falls	-0.2	0.0	-0.6	0.2
	Grand Coulee	0.1	-0.1	-0.2	0.2
1998	Libby	0.0	0.0	0.0	0.0
	Albeni Falls	0.0	0.1	0.0	0.4
	Grand Coulee	0.0	-0.1	0.0	0.2
2003	Libby	0.0	0.0	0.0	0.0
	Albeni Falls	0.0	0.2	0.1	0.6
	Grand Coulee	0.0	-0.1	0.0	0.2
MAXIMUM INTERTIE Assured Delivery					
1988	Libby	1.1	-0.3	-0.4	0.1
	Albeni Falls	0.0	0.1	-0.2	0.3
	Grand Coulee	0.1	-0.1	-0.1	0.2
1993	Libby	0.1	-0.2	-0.2	0.1
	Albeni Falls	-0.2	0.0	-0.9	0.1
	Grand Coulee	0.2	-0.1	-0.6	0.1
1998	Libby	0.0	0.0	0.0	0.0
	Albeni Falls	-0.2	0.1	-0.9	0.3
	Grand Coulee	0.3	-0.1	-0.5	0.1
2003	Libby	-0.1	0.0	0.1	0.0
	Albeni Falls	0.0	0.0	0.0	0.0
	Grand Coulee	0.0	0.0	0.0	0.0

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Table 4.2.15

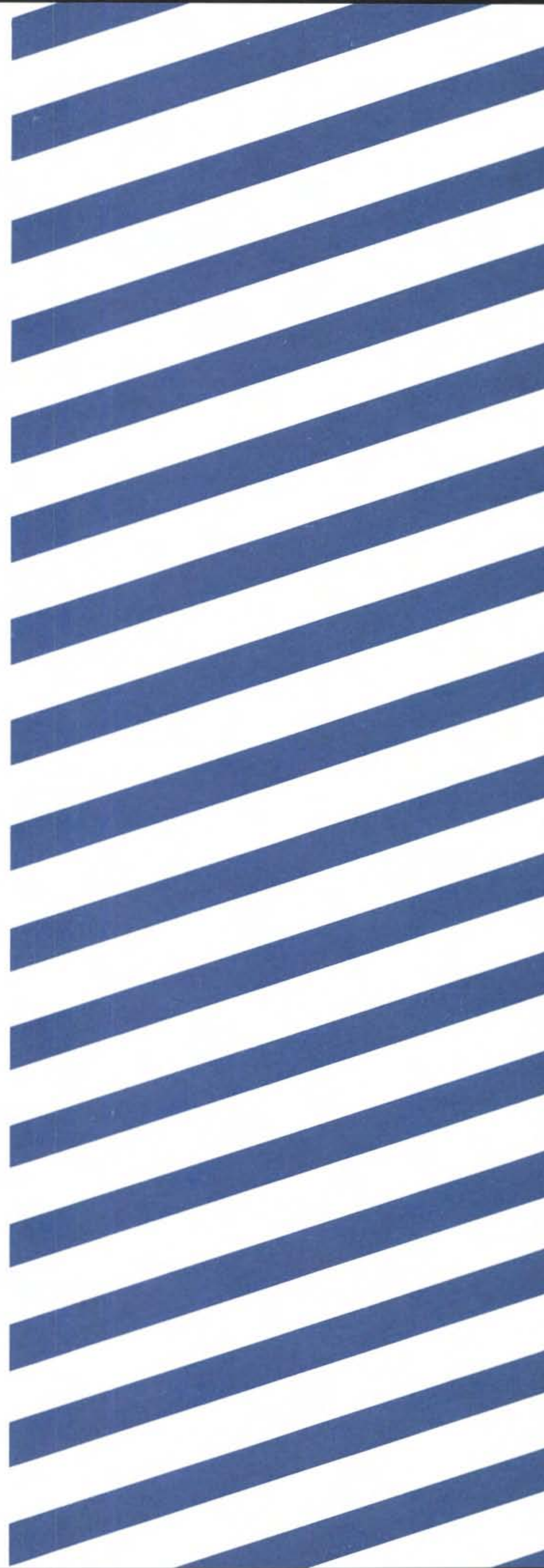
EFFECTS OF LONG-TERM FIRM CONTRACTS ON WAVE EROSION AND SITE ACCESSIBILITY INDICES
(Percent Change From Existing Contract Level)

Assuming Proposed Formula Allocation

		Wave Erosion			Site Accessibility		
		Federal Marketing	Assured Delivery	Alternative 1/ Assured Delivery	Federal Marketing	Assured Delivery	Alternative 1/ Assured Delivery
Existing Intertie							
1988	Libby	9.3	11.3	9.7 1/	-2.9	-5.4	-2.9 1/
	Albeni Falls	-0.2	-0.5	-0.2	-0.6	-1.8	-0.6
	Grand Coulee	0.2	0.6	0.3	-0.6	-1.3	-0.6
1993	Libby	0.6	0.9	0.1	-0.1	-1.4	-0.5
	Albeni Falls	0.1	-0.1	-0.1	0.2	-0.3	-0.3
	Grand Coulee	0.1	0.3	0.3	-0.2	-0.6	-0.5
1998	Libby	-0.4	-1.0	0.0	0.8	0.6	-0.9
	Albeni Falls	0.2	0.1	-0.1	0.9	0.4	-0.3
	Grand Coulee	-0.2	-0.1	0.3	0.3	0.1	-0.6
2003	Libby	0.0	0.3	2.3	0.6	0.2	-2.3
	Albeni Falls	0.1	0.0	-0.5	0.4	-0.2	-1.9
	Grand Coulee	0.0	0.1	1.1	0.0	-0.2	-2.1
Maximum Intertie							
1993	Libby	0.6	1.1	-0.3 1/	0.3	-1.2	0.6 1/
	Albeni Falls	0.1	-0.1	-0.1	0.5	-0.2	-0.3
	Grand Coulee	0.0	0.2	0.1	-0.1	-0.5	-0.1
1998	Libby	-0.4	-1.0	0.2	0.8	0.7	-1.0
	Albeni Falls	0.0	-0.3	-0.3	0.1	-1.1	-1.2
	Grand Coulee	-0.1	0.3	0.5	0.2	-0.5	-1.1
2003	Libby	-0.1	0.1	2.6	0.8	0.3	-2.0
	Albeni Falls	0.1	0.0	-0.1	0.4	0.1	-0.5
	Grand Coulee	0.0	0.1	0.6	0.0	-0.3	-1.3

1/ For Existing Intertie capacity, data for Alternative #1 is shown, for Maximum Intertie capacity, data for Alternative #2 is shown.

(VS6-PG-1321I)



4.2.3 FISH

OVERVIEW AND SUMMARY

This section of the IDU EIS examines analysis of the effects of the proposed Intertie decisions on the survival and production of resident and anadromous fish populations in the Columbia River and its tributaries. The results of the studies of impacts on fish are described in this section with more details provided in appendices D and E.

The EIS studies indicate there would be no adverse impacts to resident fish in the Kootenai River below Libby dam and in the Flathead River at Columbia Falls as a result of proposed Intertie capacity, formula allocation, or long-term contracts decisions. Resident fish in these streams would experience only very minor changes in streamflows relative to flows occurring in the No Action case, and would therefore not be expected to experience any impacts on spawning, incubation, emergence, rearing or migration. Nor is it expected that flow changes would adversely affect the production of aquatic fish food organisms.

The only resident fish in major reservoirs identified in the studies that might experience adverse impacts are those residing in Hungry Horse reservoir. Impacts at Hungry Horse result from the two long-term contracts options: Federal Marketing and Assured Delivery. Reservoir elevations under these options are predicted to decrease by an average of approximately 4 to 5 feet during some fall months, dewatering the shallow shore areas, and potentially affecting the food supply and growth of the westslope cutthroat trout, Dolly Varden, and mountain whitefish. As mean end-of-month reservoir levels decrease throughout the fall, the studies show a high frequency of a greater than 5-foot drawdown relative to the No Action alternative. There is currently no way to quantify the effects these changes in reservoir operation may have on fish production in Hungry Horse. BPA, under the Northwest Power Planning Council's (NPPC) Fish and Wildlife (Program), Section 903(b)(3), is funding a study by the Montana Department of Fish, Wildlife and Parks (MDFWP) to develop a model to quantify changes in fish production resulting from changes in reservoir operations at Hungry Horse. The Program also contains a specific process for mitigation, including funding by BPA of mitigation of fish losses caused by power operations. The mitigation process provided in the Program will be used once modeling capability is available to quantify any mitigation needs relative to current or future operational circumstances. BPA will assist Montana in undertaking a 3-year program to monitor the fishery resource of Hungry Horse and validate the MDFWP model. If monitoring, research data, and fishery modeling capabilities indicate dam operations are affecting fish adversely, BPA will consult with the U.S. Fish and Wildlife Service, the Bureau of Reclamation, the MDFWP, and the NPPC to determine appropriate mitigation alternatives.

The EIS studies show that formula allocation and long-term firm contracts options would not have significant effects on the survival of juvenile anadromous fish migrating downriver through the hydroelectric system. Intertie cases that include increasing the capacity of the Intertie show increasing mortality to juvenile fish of many stocks, the mortality being greater with the added increments of Intertie capacity. Juvenile fish mortalities associated with increased capacity would, however, be minor relative to existing survival rates or future survival rates that should be achieved with installation of planned bypass systems. In the context of the future improved migration routes for juvenile fish, the Intertie-caused decrements in survival would not be significant.

As for anadromous fish in the Hanford Reach, flow patterns throughout the Hanford Reach, and particularly at Vernita Bar, do not change substantially as a result of any of the options. Thus, there is no expected impact to Hanford Reach fall chinook spawning, incubation, and emergence as a result of any of the Intertie options studied.

4.2.3.1 Introduction

The Intertie development and use alternatives are expected to affect the operation of the hydroelectric system in the Pacific Northwest and British Columbia. The operation of hydroelectric facilities on the Columbia River and its tributaries affects the survival and production of both resident and anadromous fish populations. Survival of downstream-migrating juvenile anadromous salmonids can be directly related to the amount of hydro-regulated flow in the Columbia River system during the spring out-migration. Spill at dams during the spring and summer migration period can reduce mortality by offering an alternative to fish passage through turbines. Flows below Priest Rapids Dam affect the reproductive success of anadromous fish in the Hanford Reach. The amount of river flow below some dams such as Libby and Hungry Horse can affect the spawning, incubation, emergence, and rearing of resident fish populations, such as trout and kokanee salmon. In addition, changes in reservoir levels can influence the production of resident fish at the five major storage reservoirs (Grand Coulee, Libby, Dworshak, Albeni Falls, and Hungry Horse), by affecting food sources or disrupting reproductive stages. Low reservoir levels can also block the access of resident fish to tributary streams during spawning periods.

The following four categories of potential impacts on fish as a result of operational changes in the Federal Columbia River power system were identified during scoping and consultation sessions and analyzed for the IDU EIS:

(1) Impacts on resident fish production in five major storage reservoirs due to seasonal changes in reservoir elevations.

(2) Impacts on kokanee salmon production in the Flathead River below Hungry Horse Dam and on resident fish production in the Kootenai River below Libby Dam due to flow changes.

(3) Impacts on downstream migrant anadromous fish survival due to changes in spill and flow rates.

(4) Impacts on anadromous fish production in the Hanford Reach due to flow changes.

Section 4.2.3.2 provides an overall discussion of the studies and methods used in the analysis of fish impacts. The results of the studies of the effects of the proposed decisions on resident fish are then discussed in Section 4.2.2.3, treating resident fish production in streams first and resident fish production in reservoirs second. Mitigation is addressed when necessary.

Section 4.2.3.4 examines the studies predicting effects of the proposed Intertie decisions on Columbia Basin anadromous fish. The bulk of the discussion deals with downstream migration of anadromous fish. The first part of this section provides information projecting what potential spill and flow changes could be expected to result from the proposed Intertie actions.

The anadromous fish section then describes sensitivity analyses performed for the anadromous fish study results, followed by an examination of the effects spill and flow changes could have on survival of downstream migrating juvenile salmonids and a significance analysis of the impacts predicted to various anadromous fish stocks in the studies.

The discussion of effects on anadromous fish concludes with an analysis of the potential for impacts of the proposed Intertie decisions on adult spawning and fry emergence in the Hanford Reach.

4.2.3.2 Method of Analysis

Impact analyses are based on differences in predicted river system operations between the No Action case (Pre-IAP, Existing Capacity, and Existing Contracts) and the cases under study. A description of these cases is contained in Chapter 2. Each case represents a cumulative impact relative to the No Action case for the combinations of formula allocation, level of long-term firm contracts, and level of Intertie capacity, which make up the specific alternative cases. The additive impact or change of going from one alternative case to another is arrived at by comparing the cumulative impacts of each case relative to the No Action case.

For each of the four categories of potential fish impacts identified above, the study results are first presented for the two formula allocation options, given Existing Contracts and Existing Capacity. Following this are the results for the different contracts options with various formula allocations at the Existing Capacity level. The effects of different levels of Intertie Capacity are presented last, with different combinations of formula allocation and contracts configurations. A summary of the scenarios analyzed relative to the No Action case is presented in Table 4.2.3-1.

Table 4.2.3-1

SUMMARY OF STUDY COMPARISONS

Variable Under Analysis	Cases Compared to No Action Scenario
Formula Allocation	1. Proposed Formula Allocation, Existing Capacity, Existing Contracts
	2. Hydro-First Formula Allocation, Existing Capacity, Existing Contracts
Long-Term Firm Contracts	1. Federal Marketing, Pre-IAP Formula Allocation, Existing Capacity
	2. Federal Marketing, Proposed Formula Allocation, Existing Capacity
	3. Federal Marketing, Hydro-First Formula Allocation, Existing Capacity
	4. Assured Delivery, Pre-IAP Formula Allocation, Existing Capacity
	5. Assured Delivery, Proposed Formula Allocation, Existing Capacity
	6. Assured Delivery, Hydro-First Formula Allocation, Existing Capacity
Intertie Capacity	1. DC Upgrade, Proposed Formula Allocation, Existing Contracts
	2. DC Upgrade, Proposed Formula Allocation, Federal Marketing
	3. DC Upgrade, Proposed Formula Allocation, Assured Delivery
	4. Third AC, Proposed Formula Allocation, Assured Delivery
	5. Maximum Capacity, Proposed Formula Allocation, Existing Contracts
	6. Maximum Capacity, Proposed Formula Allocation, Federal Marketing
	7. Maximum Capacity, Hydro-First Formula Allocation, Federal Marketing
	8. Maximum Capacity, Proposed Formula Allocation, Assured Delivery
	9. Maximum Capacity, Hydro-First Formula Allocation, Assured Delivery

For each alternative, the operational changes in flow, spill, and reservoir levels were simulated with the System Analysis Model (see Appendix B, Part 1). The hydroregulation component of SAM uses randomly selected flow conditions from the 1928 to 1968 historical record adjusted for water depletions (i.e., increased irrigation withdrawals). Fourteen periods per year 1/ for 20 consecutive years of system operation

1/ With the exception of April and August, each month of the year represents a period. April and August are each divided in half with each half representing a distinct period.

(September 1987 through September 2006) were simulated 200 times for each Intertie alternative studied. From the 20-year simulations, hydro operations data for the representative years 1988, 1993, 1998, and 2003 were analyzed to determine possible fish impacts.

4.2.3.3 Resident Fish

Resident fish are freshwater fish that live and migrate within the streams and lakes of the Columbia River Basin, but do not travel to the ocean as do anadromous fish. Resident fish exist throughout the basin and are particularly important socioeconomically where anadromous fish runs are blocked by natural or manmade obstructions. Resident fish populations have become an important component of recreation associated with many of the storage reservoirs on the Columbia River.

4.2.3.3.1 Resident Fish Production In Streams

Issues. The mainstem of the Flathead River above Flathead Lake supports a large spawning population of kokanee salmon. The operation of Hungry Horse Dam, located on the South Fork of the Flathead River, has affected kokanee spawning in the South Fork and the mainstem Flathead River. Water level fluctuations have resulted in alternate wetting and dewatering of incubating eggs when flows were high during the spawning season and low during the incubation season (Fraley, 1985). Studies have shown that dewatering can cause significant mortality of kokanee eggs and pre-emergent fry, with the degree of mortality dependent on the duration and frequency of dewatering (Fraley and Graham, 1982).

To aid reproduction of kokanee in the Flathead River, the Northwest Power Planning Council has recommended that Hungry Horse Dam be operated to provide specified flows at Columbia Falls on the mainstem Flathead River. For spawning, flows should be between 3.5 and 4.5 thousand cubic feet per second (kcfs) from October 15 through December 15. For incubation, an instantaneous minimum flow of at least 3.5 kcfs should be provided from December 15 through April 30. An instantaneous minimum flow of at least 3.5 kcfs is recommended at Columbia Falls from July 1 through October 15.

The Kootenai River below Libby Dam supports populations of important resident game fish, including westslope cutthroat trout, rainbow trout, and Dolly Varden. Reduced flow below Libby Dam could interfere with spawning, incubation, emergence, rearing, and migration of resident fish and could lower production of aquatic fish food organisms. Lack of high spring flushing flows can also create sediment problems for resident fish. To protect the resident fish populations in the Kootenai River, the Council has recommended that Libby Dam be operated to provide a minimum flow of 4 kcfs except in years of extremely low runoff, when no less than 3 kcfs should be provided.

Concerns were expressed that Intertie decisions could result in flows in the Flathead River at Columbia Falls that would not be adequate to protect kokanee reproduction, and flows in the Kootenai River below Libby Dam that would not be adequate to protect resident fish populations.

Analytical Methods. The changes in flows in the Kootenai River below Libby Dam and in the Flathead River at Columbia Falls below Hungry Horse Dam were analyzed for all months of the years 1988, 1993, 1998, and 2003. Comparisons were made to the No Action case to determine the effects of different combinations of formula allocation, firm contracts, and Intertie capacity options. The analysis looked at the following changes in flow statistics for the 14 periods of the year based on 200 simulations for each period and year:

a. The mean (expected value) change in the period average flows at Columbia Falls and below Libby (Appendix D, Tables D-1 and 2).

b. The change in the frequency of occurrence of period average flows at Columbia Falls that are: (1) less than 3.5 kcfs for all months; (2) greater than 4.5 kcfs for October, November, and December (kokanee spawning period); and (3) less than 4.5 kcfs for January through September (kokanee incubation, emergence, and emigration) (Appendix D, Tables D-3 and 4). Monthly average flows below 4.5 kcfs were assumed to have the potential for impacts during the January-through-September period, based on research by the Montana Department of Fish, Wildlife, and Parks (Fraley, 1985; Fraley and Graham, 1982).

c. The change in the frequency of occurrence of flows at Libby Dam that are less than 4.0 kcfs. Flows below 4 kcfs during any period of the year are assumed to have the potential for impacts, based on conversations with the Montana Department of Fish, Wildlife, and Parks staff (Appendix D, Table D-5).

Results

Effects of Formula Allocation Options

Given Existing Intertie capacity and Existing Contracts, the Proposed Formula Allocation had very little effect on streamflows below Columbia Falls and Libby dams (see Appendix D). The period average flowrates remained essentially unchanged for both the Proposed Formula Allocation and Hydro-First options. The formula allocation options also had little effect on the frequency of flows less than 4.0 kcfs at Libby and less than 3.5 kcfs and 4.5 kcfs at Columbia Falls. Accordingly, it was concluded that these options would not have any significant adverse impact on resident fish populations at these locations.

Effects of Long-Term Firm Contracts

Both the Federal Marketing and Assured Delivery contracting options, with Existing Intertie capacity and each of the formula allocation options, caused flows at Columbia Falls and Libby to decrease slightly from the No Action case in the fall and winter months and increase slightly in the summer (see Appendix D). There appear to be no quantifiable differences between the operational changes caused by the long-term contracts options. The maximum decrease in period average flows experienced at Columbia Falls was 1.2 kcfs relative to a 7.9 kcfs flow in the No Action case in January 1988, and at Libby, 1.9 kcfs relative to a 14.9 kcfs flow in the No Action case in November of study year 1988.

There were no changes in the occurrence of period average flows less than 4.0 kcfs at Libby. The frequency of flows less than 3.5 kcfs at Columbia Falls changed less than 1 percent for all periods. The frequency of flows at Columbia Falls less than 4.5 kcfs showed only minor variations from the No Action case. The type of formula allocation did not significantly alter the impacts of the long-term contracts options. The minor flow changes at Columbia Falls and Libby as a result of long-term contracts would not have any significant adverse impacts on resident fish populations.

Effects of Increasing Intertie Capacity

Flows at Columbia Falls and Libby did not vary appreciably with different levels of Intertie capacity (see Appendix D). The type of formula allocation policy and the level of long-term firm contracts did not affect the results of the analysis of increased capacity. No significant impacts to resident fish at Columbia Falls or below Libby are expected from increased capacity.

4.2.3.3.2 Resident Fish Production In Reservoirs

Issues. Drawdown of reservoirs for power production, irrigation, or flood control can affect game fish production by altering the physical and biological characteristics within and below the reservoirs. Drawdown reduces surface area, volume, shoreline length, area in the productive shoreline zone volume in the layer of water with sufficient light for plant growth, and volumes in preferred temperature strata for trout. Large outflows reduce hydraulic residence times and weaken thermal structure.

The biological consequences of these physical changes may include reduced habitat for both game fish and their food organisms (e.g., bottom-dwelling invertebrates and zooplankton), decreased production of food organisms (due to weakened thermal structure), exposure of redds (nests) and eggs to desiccation (drying) and freezing temperatures, limitation of access to tributary spawning streams and reduction of shoreline spawning habitat. Table 4.2.3-2 contains information on critical months for reservoir game fish spawning. Losses of reservoir zooplankton can occur in outflows during drawdown; however, these zooplankton may serve as a food source for downstream fish.

Table 4.2.3-2

CRITICAL MONTHS FOR RESERVOIR GAME FISH SPAWNING

	Reservoir				
Species	Hungry Horse	Libby	Grand Coulee	Dworshak	Albeni Falls
Kokanee	N/A	Sept.-Nov.	Sept.-Nov.	Sept.-Nov.	Sept.-Nov.
Cutthroat	May-July	May-July	N/A	May-July	May-July
Rainbow Trout	April, May	April, May	April, May	April, May	April, May
Dolly Varden	Aug.-Oct.	Aug.-Oct.	N/A	Aug.-Oct.	Aug.-Oct.
Walleye	N/A	N/A	April, May	N/A	N/A
Smallmouth Bass	N/A	N/A	April-July	June-July	N/A
Mountain Whitefish	Nov.-Jan.	Nov.-Jan.	Nov.-Jan.	Nov.-Jan.	Nov.-Jan.

Concerns have been expressed that expansion of the Intertie and changes in policy for its use may result in changes in drawdown that would adversely affect resident fish populations in Hungry Horse, Libby, Grand Coulee, Dworshak, and Albeni Falls reservoirs. All of these reservoirs are currently subjected to drawdown for flood control and power production. Any increased drawdown resulting from Intertie development and use could increase existing impacts of reservoir level fluctuations. A brief biophysical sketch of each of the five reservoirs is presented below.

Hungry Horse Reservoir: Common game fish species in Hungry Horse Reservoir include westslope cutthroat trout, Dolly Varden, and mountain whitefish. Westslope cutthroat trout is the primary species sought by anglers in the reservoir. Annual maximum drawdown averaged 64 feet from 1955 through 1964, 92 feet from 1965 through 1975, and 66 feet from 1976 through 1987. Larger-than-average drawdown from 1965 to 1975 is reported to adversely affect the growth and survival of cutthroat trout (May and Zubik, 1985). Studies on Hungry Horse and other reservoirs have indicated the importance of the shallow near-shore, or littoral zone. The dewatering of this zone in the fall in Hungry Horse Reservoir and subsequent loss of benthic insect production and littoral habitat for westslope cutthroat trout has reduced the growth and survival of this species. The period from September through November is the most important season for fish growth, with cutthroat achieving almost 60 percent of their annual biomass increment during this period. Nearly all biological productivity occurs in the reservoir during the period from April through November. BPA has funded a study at Hungry Horse to determine the effects of reservoir level fluctuations on fish and fish food production. From the study, which began in 1983, a model is being developed that will estimate changes in resident fish production under various operational regimes. This will assist BPA and others to determine if mitigation is needed and at what levels. The model is expected to be operational by July 1988.

Libby Reservoir (Lake Koocanusa): Common game fish species in Libby Reservoir include westslope cutthroat trout, rainbow trout, Dolly Varden, and kokanee salmon. Annual maximum drawdown averaged 114 feet from 1976 through 1987 (Corps, 1988). As at Hungry Horse, BPA has funded a study since 1983 to determine fish and fish-food production under various operational regimes. The model is expected to be operational by July 1988.

Grand Coulee Reservoir (Lake Franklin D. Roosevelt): Grand Coulee Reservoir supports an economically valuable recreational fishery for walleye and rainbow trout. Smallmouth bass and kokanee are present in the reservoir and contribute to the sport fishery. Yellow perch serve as an important forage species for walleye. During the period 1976-1987, annual drawdown averaged approximately 58 feet, with a maximum drawdown of approximately 79 feet in 1982 (Corps, 1988). As partial mitigation for anadromous fish losses above Grand Coulee and reservoir level fluctuations caused by hydro operations, BPA, under the Northwest Power Planning Council's Fish and Wildlife Program, is developing plans to construct and fund operation of two kokanee hatcheries for stocking Lake Roosevelt. Construction is presently programmed for 1990. Habitat improvement projects in some tributaries to the reservoir are also planned.

Dworshak Reservoir: Kokanee are the most popular sport fish caught in Dworshak Reservoir, followed by rainbow trout and smallmouth bass. Cutthroat trout, Dolly Varden, largemouth bass, whitefish, and northern pike are found in the reservoir, but generally contribute little to the sport fishery. The annual maximum drawdown is approximately 115 feet. In 1986, BPA began funding two 4-year projects to determine the effects of hydro operations on the fish in Dworshak Reservoir. The study results could lead to recommendations for measures to protect and enhance the fish in the reservoir.

Albeni Falls Reservoir (Lake Pend Oreille): Lake Pend Oreille supports important sport fisheries for kokanee and the Kamloops strain of rainbow trout. Other less important game fish species include lake trout, Dolly Varden, mountain and lake whitefish, and various spiny-ray fish (e.g., bass, perch, blue gill, etc.). The normal annual drawdown is 11.5 feet (Corps of Engineers, 1985a). BPA funded 50 percent of the construction costs of the Cabinet Gorge Hatchery operated by the Idaho Department of Fish and Game. The hatchery, completed in 1985, was constructed as mitigation for the Albeni Falls and Cabinet Gorge dams which affected Kokanee spawning. The hatchery has a production goal of 20 million kokanee fry per year to be stocked in Lake Pend Oreille. BPA is funding a 6-year study to evaluate the contribution of the hatchery to the fishery in the lake.

Analytical Methods. There is very limited information on the quantification of biological impacts at reservoirs associated with changes in draft levels and seasonal timing. Based on consultation with the Corps of Engineers and the Montana Department of Fish, Wildlife, and Parks, changes were considered to have the potential for adverse fishery impacts if, during the April through November period of biological activity: (a) the mean change in end-of-period reservoir elevations was greater than a 2-foot decrease; or (b) the frequency of an elevation decrease of greater than 5 feet was greater than 10 percent. These criteria are used in the EIS only as a flag for potential impacts.

The relative changes in reservoir elevations associated with Intertie decisions were analyzed for Hungry Horse, Libby, Grand Coulee, Dworshak, and Albeni Falls reservoirs. The end-of-period elevations, as simulated by the System Analysis Model, were compared for all 14 periods (12 months, with April and August split) for the years 1988, 1993, 1998, and 2003. The reservoir analysis looked at the following differences in elevation statistics between each test case and the No Action case for each reservoir, based on 200 simulations for each period of each year:

a. the mean change in the end-of-period reservoir elevations (Appendix D, Tables D-6 through D-10);

b. the frequency of occurrence of simulated elevation increases and decreases (relative to the No Action case) of greater than 5 feet (Appendix D, Tables D-11 through D-15).

Sensitivity Analyses

The sensitivity of the changes in reservoir operations to key assumptions used in the SAM were analyzed and discussed in Section 4.2.1.5. Detailed descriptions of these sensitivity analyses are provided in Appendix B, Part 7 and reservoir elevation data are provided in Appendix C, Part 2. The results of these studies show the potential for additional impacts to resident fish under two of the assumptions tested. The first is the assumption of low PNW loads. The second is the assumption of increased power sales and power exchanges under the Proposed IAP.

The analysis of the low PNW loads assumption compared reservoir elevations under the Proposed Formula Allocation, existing level of firm contracts, and Maximum Intertie capacity alternative to those under the No Action case with both alternatives having approximately 3000 aMW of firm surplus throughout the 20-year study period. Under this assumption, increased capacity causes decreased reservoir elevations relative to the No Action case primarily at Hungry Horse, Libby, and Grand Coulee. See Table 4.2.8 for mean changes in the end-of-period reservoir elevations under this assumption. These changes are not considered to be significant to resident fish at Libby and Grand Coulee since decreases greater than 2 feet tend to occur in the winter months when the reservoirs are relatively inactive biologically. At Hungry Horse however, substantial decreases in mean end-of-month elevations (up to 4.5 feet) occur during the spring and fall when the reservoirs are biologically active.

The analysis of different long-term contract combinations which might occur under the Proposed IAP, found that additional amounts of seasonal power exchanges and long-term firm sales with correspondingly less capacity/energy exchanges might have additional impacts to resident fish. Three different levels of seasonal power exchanges with additional long-term firm sales were analyzed. Section 4.2.1.5, Appendix B, Parts 4 and 7, and Appendix C, Part 2 provide detailed descriptions and reservoir elevation data for these analyses. The alternative with the Maximum level of seasonal power exchanges (950 MW capacity in addition to Existing Contacts) was the only case showing the potential for additional resident fish impacts beyond those reported for the Assured Delivery and Federal Marketing alternatives. For this alternative, reservoir elevations tended to be substantially lower than the No Action alternative during the critical fish production period of September through November at Hungry Horse, Libby, and Dworshak. Maximum decreases in the mean end-of-period reservoir elevations during these months were 7.7 feet at Hungry Horse, 3.9 feet at Libby, and 3.8 feet at Dworshak. The two alternatives at lower levels of seasonal power exchanges (500 MW and 700 MW of capacity in addition to Existing Contract amounts) did not show the potential for additional resident fish impacts beyond those reported for the Assured Delivery and Federal Marketing alternatives.

Results

The results reported in the sections to follow are based on differences between reservoir elevations observed under the No Action versus selected test cases. For a summary of the test cases, please refer back to Table 4.2.3-1.

Effects of Formula Allocation Options

During study years 1993, 1998, and 2003, neither the Proposed Formula Allocation nor the Hydro-First option had a substantial effect on reservoir elevations. For the reservoirs studied, the maximum decrease in the mean end-of-month reservoir elevation was 0.7 feet or less during all periods of these 3 years. In 1988, however, the Proposed Formula Allocation generally increased reservoir levels in the fall by as much as approximately 1 foot at Libby, Dworshak, and Hungry Horse. Reservoir levels remained essentially unchanged at Grand Coulee and Albeni Falls. The Hydro-First option decreased reservoir elevations throughout much of 1988 for all five reservoirs, primarily in the fall and winter. The greatest reductions occurred in the fall and winter at Hungry Horse, with reservoir elevations reduced by 1.6 feet, 3.6 feet, and 3.4 feet, in September, October and November, respectively. During this same period, the maximum reduction at Libby was 2.1 feet and at Dworshak, 1.7 feet. Elevations were virtually unchanged at Albeni Falls and Grand Coulee. Changes in reservoir levels were slight during the spring and summer months at all reservoirs.

For both the Proposed Formula Allocation and the Hydro-First Options, the frequency of the occurrence of reservoir levels decreasing from the Pre-IAP option by more than 5 feet never exceeded 6.5 percent for all years, except under the Hydro-First option in 1988. Under the Hydro-First option, Hungry Horse showed the greatest frequency, reaching 32.0 percent in October of 1988. The frequency at Libby was 13.5 percent in October, and Dworshak reached 11.5 percent in December.

The Hydro-First option exceeds the criteria for potential impacts identified in the analytical methods section only in study year 1988 in October and November at Hungry Horse and in October at Libby. Because these occurrences are minor and infrequent, no significant impacts on resident game fish production or aquatic productivity are expected from the formula allocation options.

Effects of Long-Term Firm Contracts

Long-term firm power contracts show a much greater effect on reservoir elevations than do changes in formula allocation policy or Intertie capacity. Reservoir levels were generally lower in the fall and winter months for both the Federal Marketing and Assured Delivery cases. The Federal Marketing option caused slightly greater reservoir drafts than did Assured Delivery.

The reservoirs most affected by firm marketing were Hungry Horse, Dworshak, and Libby, with average reservoir levels dropping below those of the No Action case by as much as 5.1 feet at Hungry Horse, 2.9 feet at Dworshak, and 2.3 feet at Libby during the critical months of September through November. The only exception to this trend of decreased reservoir levels during critical months was at Libby in 1988, where reservoir levels increased by as much as 5.1 feet and 3.4 feet for the Assured Delivery and Federal Marketing cases, respectively. For the remaining periods of biological activity (April through August), the maximum average decreases in elevation were 2.3 feet at Hungry Horse, 1.0 feet at Dworshak, and 0.5 feet at Libby. Little change occurred at Albeni Falls and Grand Coulee.

The effects of the long-term contracts on reservoir elevations changed only slightly with different formula allocation policies. Different levels of capacity also had little effect on the changes due to long-term contracts.

The frequency of occurrence of reservoir elevations decreasing by more than 5 feet from the No Action case, never exceeded 10 percent at Libby, Grand Coulee, or Albeni Falls for either the Federal Marketing or Assured Delivery cases. Occurrences at Dworshak for both options ranged from 3.0 to 16.5 percent, September through November, and were generally less than 10 percent in the remaining biologically active period, April through August. There were several times when the frequency of occurrence was greater than 10 percent at Hungry Horse, primarily August through February (Table 4.2.3-3). Federal Marketing tended to have the greatest overall effect. A substantially greater frequency of 5-foot elevation decreases was observed in 1993 under the Federal Marketing case. These frequencies changed only slightly when combined with differing formula allocation options and Intertie capacities.

Table 4.2.3-3

HUNGRY HORSE
FREQUENCY (%) OF RESERVOIR ELEVATION INCREASES AND DECREASES
GREATER THAN 5 FEET FROM THE NO ACTION CASE

	FEDERAL MARKET*				ASSURED DELIVERY*			
	YEAR				Year			
	1988	1993	1998	2003	1988	1993	1998	2003
	+/-	+/-	+/-	+/-	+/-	+/-	+/-	+/-
September	2.5/14.5	4.0/37.0	0.5/16.5	0.5/15.5	5.0/12.5	5.0/23.5	0.5/25.5	0.0/13.0
October	13.0/20.0	4.0/46.5	1.0/26.5	0.5/25.5	14.0/16.5	7.0/23.0	1.0/31.0	1.0/20.0
November	13.0/18.0	3.5/47.0	1.0/26.5	0.5/25.5	14.0/15.0	7.0/23.0	1.0/31.0	1.5/20.5
December	13.5/15.0	5.5/40.5	2.0/32.0	0.5/28.5	21.0/14.5	14.5/15.5	1.0/28.5	5.0/19.0
January	26.0/13.0	8.0/27.5	2.0/16.5	0.5/17.5	45.5/10.5	14.5/11.0	2.0/18.0	5.5/14.5
February	19.0/11.0	10.0/17.0	3.0/ 8.0	1.0/11.0	31.0/ 9.0	15.5/ 7.5	1.5/12.0	3.5/10.5
March	13.0/10.0	11.0/12.0	4.5/ 4.0	1.0/ 9.0	18.0/ 9.0	15.0/ 7.0	4.5/ 9.5	5.5/ 7.5
April 1	12.5/ 9.0	10.5/11.0	4.5/ 4.0	1.0/ 8.5	15.5/ 8.0	14.5/ 6.5	4.5/ 8.0	4.5/ 7.5
April 2	13.0/ 9.5	8.5/10.0	5.5/ 2.5	2.5/ 9.5	15.0/ 8.0	12.0/ 6.0	4.5/ 5.0	5.0/ 7.0
May	9.0/ 5.5	6.5/ 5.5	3.5/ 0.5	1.0/ 6.5	12.0/ 6.0	9.5/ 4.5	5.0/ 2.5	2.5/ 5.5
June	6.5/ 5.0	6.0/ 4.0	2.5/ 1.0	0.0/ 4.5	11.5/ 5.0	8.0/ 3.0	3.5/ 2.0	3.5/ 2.5
July	3.0/ 9.0	6.5/ 4.5	2.5/ 4.0	0.5/ 4.5	4.0/ 6.0	8.0/ 3.5	3.5/ 3.5	3.0/ 2.5
August 1	2.5/12.0	5.0/ 4.5	2.5/ 5.0	0.5/ 4.5	3.0/ 10.0	5.0/ 5.0	3.5/ 4.5	3.5/ 3.0
August 2	2.5/17.5	3.0/ 7.0	0.5/ 6.0	0.5/ 8.5	3.0/ 20.0	3.5/10.0	1.0/ 5.0	1.5/ 6.0

* Long-term Marketing cases with the Pre-IAP formula allocation and Existing capacity. Frequencies are expressed as the percent of 200 simulations with the SAM. The (+) sign indicates increases and the (-) sign indicates decreases.

The criteria for potential impacts were exceeded at Hungry Horse, Libby, and Dworshak. For Libby and Dworshak, the exceedances were minor and occurred only in October at Libby, and in September and October at Dworshak. No significant impacts on resident fish production are expected at Libby, Albeni Falls, Grand Coulee, and Dworshak since the changes in reservoir elevations were minor and infrequent. The impacts on resident fish of decreased reservoir levels during September through November at Hungry Horse associated with Federal Marketing and Assured Delivery cannot be quantified, but could be significantly adverse. Adverse impacts result from dewatering the littoral zone in the fall and the subsequent loss of benthic insect production and littoral habitat for westslope cutthroat trout, Dolly Varden, and mountain whitefish. This is the period when the cutthroat trout achieve their greatest growth.

Mitigation. As a means of precluding adverse impacts to resident fish due to projected reductions in reservoir levels, BPA will undertake measures to increase resident fish use of Hungry Horse tributaries. The efforts will include funding of imprint planting of westslope cutthroat trout and mountain whitefish in four tributaries (Felix, Harris, Margaret and McInernie Creeks) over a 5-year period. BPA will also fund off-site fish habitat improvements on Brennemans and Siderius Sloughs on the Flathead River, involving cleaning of spawning gravels and imprint planting of cutthroat trout, kokanee, and mountain whitefish.

The Columbia Basin Fish and Wildlife Program already addresses Hungry Horse operational impacts and a process for mitigation. Research is currently being conducted and, based on the knowledge gained, recommendations to protect resident fish will be developed and considered for implementation. The Program specifies an existing mitigation process to be implemented by BPA when reservoir drawdowns due to power operations are excessive. Section 903(b)(1)(d) of the Program states "In years when the drawdown limit (85 feet at Hungry Horse) is exceeded for power purposes, Bonneville shall fund the mitigation of fish losses to the extent those losses are caused by power operations."

In addition, BPA will work with the Montana Department of Fish, Wildlife and Parks to monitor potential effects on resident fish of operational changes resulting from Intertie decisions. If the monitoring program indicates significant impacts are occurring as a result of the Intertie actions, information developed during the monitoring program and as a result of continuing research will be used by BPA, the Montana Department of Fish, Wildlife, and Parks, and the Northwest Power Planning Council to develop and implement effective mitigation measures.

Effects of Increasing Intertie Capacity

Changes in Intertie capacity had very little effect on reservoir elevations. The effect of increased capacity, regardless of formula allocation and long-term contracts options, was less than a 1-foot mean change in end-of-period elevations at all five storage reservoirs. Similarly, capacity level had little effect on the frequency of occurrence of reservoir elevation changes greater than 5 feet.

No significant impacts to resident fish as a result of Intertie capacity increases would be expected, given the projected changes in reservoir operations.

4.2.3.4 Columbia Basin Anadromous Fish

A large number of anadromous fish stocks is produced in the Columbia River Basin above Bonneville Dam. The stocks are generally grouped as Upper River spring chinook, Upper River summer chinook, fall chinook, coho salmon, sockeye salmon and steelhead trout. These groups of stocks are described in general in Appendix E, Part 1. A list of viable anadromous fish stocks originating in the Columbia Basin is given at the beginning of Appendix E, Part 7.

Anadromous fish are a resource important to the Pacific Northwest. The value of the sport and commercial fisheries dependent on fish production from the Columbia Basin was estimated to be $108 million for 1985 (NMFS, 1987). With increasing run sizes experienced in recent years this value should be increasing substantially. Anadromous fish also have high cultural and religious value to Columbia River Basin Tribes and others.

4.2.3.4.1 Downstream Migrant Survival

Issues

The development of the dams and hydroelectric projects on the Columbia and Snake Rivers reshaped the natural flows of the rivers. Runoff during the spring is retained in storage reservoirs, such as Grand Coulee, Hungry Horse, Libby, and Dworshak for use during periods when flows are naturally low. Regulating river flows in this fashion substantially increases the capability to produce firm energy and to provide flood control, irrigation, and recreational benefits. But it also reduces river flows during the spring and early summer when juvenile salmon and steelhead are migrating downstream to the ocean.

The run-of-river dams which have little or no storage capabilities (i.e., Wells through Bonneville on the Columbia River and Lower Granite through Ice Harbor on the Snake River) have changed the Columbia from a free-flowing river to a series of reservoirs, with slow movement of water. The reduced flows through the river system have increased the time required for juveniles to migrate from spawning and rearing habitats to the ocean. This increase in travel time increases the juveniles' exposure to predators and can affect the ability of the juvenile salmonids to make the transition from freshwater to saltwater. Reduced flows can also contribute to higher water temperatures, different water chemistry, and greater susceptibility of fish to disease. These flow-related impacts occur in addition to mortality that results as fish pass each dam. Fish not guided through powerhouse bypass systems or over spillways can sustain 5 to 30 percent mortality passing through generator turbines.

In 1980, Congress passed the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). The Northwest Power Act created the Northwest Power Planning Council (Council) and charged it with developing a Columbia River Basin Fish and Wildlife Program (Program). The Northwest Power Act directs certain Federal agencies to "protect, mitigate, and enhance" Columbia River fish and wildlife resources which were adversely affected by construction and operation of the Columbia River hydroelectric system. The Northwest Power Act seeks to provide "equitable treatment" for fish and wildlife resources, along with other project purposes, in the operation of the hydro system.

The Northwest Power Act's direction to protect, mitigate, and enhance fish and wildlife resources affected by the hydroelectric system is a dynamic process as implemented through the Council's Program. Measures to achieve fish and wildlife protection are developed publicly and include revisions to the Council's Program as needed. As new information becomes available or the status of fish and wildlife populations change, the Program is adjusted to meet Congress' mandate for fish and wildlife.

The Council established a water budget to increase river flows during the peak spring out-migration period. The Water Budget is a specified volume of water (4.64 million acre feet) which can be used to supplement flows from April 15 through June 15 to facilitate downstream juvenile migrations. Separate water budgets were established for the Mid-Columbia and Lower Snake rivers.

In addition to providing increased flows, the Council's Program sought to improve conditions as fish pass through hydro projects. Juvenile anadromous fish migrating downstream can travel past dams in several ways. They can pass through turbines, pass over the spillway if water is being spilled, or pass through bypass systems. At certain dams with bypass systems, juveniles can be collected for downstream transport via truck or barge to avoid further delays and mortality at subsequent hydro projects. The fish that enter the turbines can be killed or injured by changes in pressure, by contact with moving turbine blades, or by the shearing action of water in the turbine and discharge plume. In addition, juvenile salmonids may become stunned and disoriented after passing through the turbines, increasing their vulnerability to predators. Although some mortality results as fish are spilled, increasing the amount of spill at a dam reduces the number of fish which pass through the turbines, thereby reducing overall mortality. However, spill at transport projects (i.e., Lower Granite, Little Goose, and McNary) can be detrimental since less fish would be collected for transportation. In years of large runoff, high levels of spill can result in nitrogen supersaturation which can cause the often fatal gas bubble disease in juvenile fish.

There are three categories of spill: (1) planned fish spill; (2) overgeneration spill; and (3) forced spill. Planned fish spill is the amount of spill planned by the Corps of Engineers to achieve specific dam passage survival objectives at Federal projects. Planned spill also includes spill levels specified by Federal Energy Regulatory Commission (FERC) Agreements for the Mid-Columbia Public Utility District projects. Overgeneration spill is water spilled due to a lack of market or Intertie capacity. Forced spill is water that is spilled when powerhouse hydraulic capacity has been exceeded.

Concern has been expressed that the proposed Intertie actions could reduce the amount of spill, specifically the amount of overgeneration spill, and thereby increase the mortality of downstream migrants by causing more fish to pass through turbines. This decrease in juvenile survival would cause decreased numbers of adults for harvest and for some stocks, could decrease the number of adults returning to spawn.

As previously discussed, there is also concern that potentially lower spring flows resulting from the proposed Intertie actions could reduce survival of downstream migrants. These concerns are addressed in the IDU EIS by first analyzing the changes in flows and spill that might result from the proposed actions. Then potential changes in the survival of juvenile fish of each stock migrating through the hydrosystem are modeled, taking into account all effects of hydroelectric operations, including spill and flow, and all ongoing mitigation actions. The next part of this section summarizes the spill and flow changes that would be expected to result from the various IDU options. This is followed by a discussion of the effects these spill and flow changes would have on survival of downstream migrating juvenile salmonids.

Spill and Flow Changes: Analytical Methods

Simulated flows at Lower Granite and Priest Rapids from SAM for the years 1988, 1993, 1998, and 2003 were analyzed for changes during the juvenile spring migration months (April through June). These two projects are used for the analysis because they are indicative of the flows in the Lower Snake and Mid-Columbia Rivers and, collectively, they determine the flow in the Lower Columbia. Water budget flows, as specified in the Council's 1987 Program, are also measured at these two locations. The Water Budget volume is available to augment flows during the period of April 15 through June 15. SAM simulates the Water Budget flows at Priest Rapids during the April 16-30 and May periods, and at Lower Granite during the May period. Comparisons were made between Intertie alternatives and the No Action case using April 1-15, April 16-30, May, and June average flows.

Decreases in flow of greater than 5 kcfs at Lower Granite and 10 kcfs at Priest Rapids are used to indicate the potential for delayed travel time. These threshold values are based on an analysis of the mean April-through-June flows, using travel-time-flow relationships as cited by Karr (1982). This analysis indicates that travel time through the hydroelectric system would be approximately one day longer for fish entering the Lower Snake River and Mid-Columbia River projects when Lower Snake flows decrease by 5 kcfs, Mid-Columbia flows decrease by 10 kcfs, and Lower Columbia flows subsequently decrease by 15 kcfs.

For the IDU Final EIS analysis, the planned fish spill is based on the 1987 Corps of Engineers spill plan at the Federal projects and the current FERC Settlement Agreement for the Mid-Columbia projects. Planned fish spill is not affected by the IDU alternatives. Overgeneration spill (i.e., spill resulting when flows and resulting hydro generating capabilities are greater than available markets or Intertie size) is the type of spill which is affected by the IDU alternatives. Overgeneration spill is a product of the hydrosystem as a whole and may be allocated on an operational basis to any run-of-river project. Overgeneration spill is typically not provided at Lower Granite, Little Goose, or McNary, since these projects have bypass and fish transportation facilities. Consequently, additional spill at these projects would not provide benefits to fish. In SAM, the overgeneration spill is allocated using spill priority lists developed from a review of Fish Passage Center spill requests (See Appendix E, Part 3).

The total percent spill at each of the run-of-river projects (Wells through Bonneville on the Columbia River and Lower Granite through Ice Harbor on the Snake River) for the study years 1988, 1993, 1998, and 2003 was analyzed for changes during the juvenile migration periods of April through August 15. This spill is the total of planned spill, overgeneration spill, and forced spill.

The overgeneration spill for the hydrosystem as a whole was also analyzed for the months of April through August. Only the years 1993, 1998, and 2003 were included in this analysis since Intertie capacity has by far the greatest effect on overgeneration spill and 1988 had no changes in Intertie capacity.

The following changes in flow and spill statistics were analyzed for selected case comparisons, based on 200 simulations for each period and year of analysis:

(a) The mean (expected value) change in the period average flows at Priest Rapids and Lower Granite.

(b) Frequency of occurrences of flow increases and flow decreases at Priest Rapids of greater than 10 kcfs, when the flow rate is less than 140 kcfs. 1/

(c) Frequency of occurrences of flow increases and flow decreases at Lower Granite of greater than 5 kcfs, when the flowrate is less than 140 kcfs.

(d) The change in the frequency of meeting the Water Budget flows during the periods of April 16-30 and May at Priest Rapids (115 kcfs in both periods), and the period of May at Lower Granite (85 kcfs).

(e) The mean change in total spill for the periods April 1-15, April 16-30, May, June, July, and August 1-15 for the following run-of-river projects: Bonneville, The Dalles, John Day, McNary, Ice Harbor, Lower Monumental, Lower Granite, Little Goose, Priest Rapids, Wanapum, Rock Island, Rocky Reach, and Wells. 2/

(f) The mean monthly hydrosystem overgeneration spill for April, May, June, July and August averaged over the years 1993, 1998, and 2003.

The statistics on spill and flow changes as described above are given in Appendix E, Part 2.

Spill and Flow Changes: Results

The results reported in the following sections are based on differences between the same test cases summarized in Table 4.2.3-1 and the No Action case.

Effects of Formula Allocation Options

Flows: Priest Rapids. Effects on flows were similar for both the Proposed and Hydro-First formula allocation options for the five periods

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1/ 140 kcfs is the optimum flow level for Priest Rapids and Lower Granite identified in the Council's Fish and Wildlife Program (1987).

2/ Total spill changes were only analyzed for 40 of the 200 simulations due to limited amounts of data. See "Survival Changes: Analytical Methods" later in this section for a discussion of the use of 40 versus 200 SAM simulations.

tested (April 1-15, April 16-30, May, June, and July). The frequency of meeting Water Budget flows changed no more than 0.5 percent for both alternatives. The average flows never decreased more than 2.4 kcfs for the periods tested. For both options for all periods tested, the analysis of flows below 140 kcfs showed that the frequency was less than 10 percent for being greater than, or less than, the No Action case by more than 10 kcfs.

Flows: Lower Granite. For the periods tested, only minor changes (-0.1 to +0.2 kcfs) occurred in the mean average flows at Lower Granite Dam for both formula allocation options. The frequency of meeting Water Budget flows did not change for either of the alternatives. For both alternatives, the analysis of flows below 140 kcfs showed that the frequency was zero for being greater than or less than the No Action case by more than 5 kcfs.

Spill: Changes in spill were similar for both formula allocation options. For all test periods at all dams, the maximum decrease in the mean total spill was 1.3 percent and the maximum increase was 0.7 percent There were no substantial changes in hydrosystem overgeneration spill.

Effects of Long-Term Firm Contracts

Flows: Priest Rapids. For the five periods tested, average flows of the three Federal Marketing and three Assured Delivery options varied both above and below the No Action alternative. A comparison of the data on flow changes for contract years 1988 through 2003 showed that each alternative had only minor effects on flows. The differences in the flow changes between the Federal Marketing and Assured Delivery firm contract levels, regardless of formula allocation option, were very small.

Under all options, for all periods and years analyzed, no changes in mean flows were found to be greater than or less than the No Action alternative by more than 3.6 kcfs and 2.1 kcfs, respectively. The frequency of meeting Water Budget flows changed no more than 1.3 percent for the Federal Marketing options and 0.8 percent for the Assured Delivery options.

The analysis of flows below 140 kcfs showed that the frequency of being greater than or less than the No Action alternative by more than 10 kcfs was greatest during the early April test period for all years, and the June test period in 1988 and 1993. For these periods, the long-term firm contract alternatives show a higher frequency of flows greater than the No Action alternative. The greatest change was experienced during the April 1, 1988, period when the frequency of period average flow changes greater than the No Action alternative ranged from 14.4 to 20.9 percent. For the remaining test periods (April 2 through July), the frequency for being greater than or less than the No Action alternative by more than 10 kcfs was 0 to 14.3 and 1 to 6.5 percent, respectively.

Flows: Lower Granite. There were only minor changes from the No Action alternative in the mean average flows at Lower Granite Dam (from no change to an increase of 0.2 kcfs) as a result of either firm contract option. The frequency of meeting Water Budget flows did not change for any of the alternatives. In all cases, the analysis of flows below 140 kcfs showed that the frequency was less than 1.0 percent of being greater than or less than the No Action alternative by more than 5 kcfs. The type of formula allocation option in place had no effect on the firm contract impacts.

Spill: For all years and projects, differences in spill between the No Action and the Federal Marketing and Assured Delivery contract levels were minimal. Under the Federal Marketing options, the mean change in total spill ranged from a maximum decrease of 1.1 percent to a maximum increase of 0.8 percent. The mean change in spill under the Assured Delivery options ranged from a maximum decrease of 1.3 percent to a maximum increase of 2.9 percent for all test periods. The mean overgeneration spill for the April through August period in 1993, 1998, and 2003 was 606 average MW for the No Action case, decreasing to 585 MW under the Federal marketing alternative, and increasing to 644 MW under the Assured Delivery alternative (both with the Proposed Formula Allocation option).

Effects of Increasing Intertie Capacity 1/

Flows: Priest Rapids. Period average flows tended to be higher in the April 1-15 period and lower in the April 16-30 period for all years for alternatives involving increased capacity. For these two periods, the changes ranged from an increase of 2.4 kcfs to a decrease of 3.0 kcfs. The change in mean flows for all other periods ranged from an increase of 2.6 kcfs to a decrease of 0.9 kcfs. The frequency of meeting Water Budget flows changed no more than 1.3 percent for the DC Upgrade options, 1.0 percent for the Third AC option and 1.0 percent for the Maximum Capacity options.

The analysis of flows below 140 kcfs showed that the frequency of being greater than or less than the No Action alternative by more than 10 kcfs was greatest during the April 1-15 test period for all years, and the June period for 1993. For the April 1-15 period, the frequency of period average flows greater than the No Action alternative by more than 10 kcfs ranged from 3.8 to 18.2 percent. The frequency of period average flows less than the No Action alternative by more than 10 kcfs ranged from 1.8 to 9.6 percent. For all other periods, the frequency of 10 kcfs flow differences was less than 6 percent for all capacity alternatives. The only exception was May 1993, when there was an increase in the frequency (between 8.7 and 10.7 percent) of flow decreases greater than 10 kcfs for the increased capacity alternatives with Assured Delivery. The magnitude

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1/ Year 1988 was excluded from these analyses since none of the proposed capacity options could be in operation that soon.

of this exception is not considered significant. The types of formula allocation and different levels of long-term firm contracts had little effect on the impact of Intertie capacity on Mid-Columbia flow rates.

Flows: Lower Granite. At Lower Granite Dam, capacity increases produced only minor changes in mean average flow rates. The frequency of meeting Water Budget flows did not change for any of the alternatives. The analysis of flows below 140 kcfs showed that in all cases the frequency for flows being greater than or less than the No Action alternative by more than 5 kcfs was less than 1.0 percent. There was no substantial difference in the Intertie capacity effects on Snake River flows under different types of Formula Allocation and long-term firm contracts.

Spill: Table 4.2.3-4 summarizes the maximum decrease in period average total spill for the increased capacity alternatives at each run-of-river project for the six test periods. The type of Formula Allocation and the firm contract options in place had very little effect on the spill changes due to capacity increases.

In general, the effects of the DC Upgrade alternatives were similar for each year of analysis. Decreases in spill in July for all contract years at Ice Harbor and Lower Monumental dams were noticeably greater (8.1 to 13.5 percent and 8.0 to 13.6 percent, respectively) than those for the other test periods (0 to 5.8 percent). The maximum decrease in mean spill for all other facilities was 5.1 percent. There were substantial decreases in hydrosystem overgeneration spill under the DC Upgrade alternatives. The mean overgeneration spill for the April through August period in 1993, 1998, and 2003 was decreased from 606 MW under the No Action alternative, to 339 MW under the DC Upgrade with the Proposed Formula Allocation and Existing Contracts.

Under the Third AC alternative, changes from the No Action case in period average spill were similar for each year of analysis. At both Ice Harbor and Lower Monumental, decreases in spill were discernibly higher in July (11.4 to 15.4 percent and 11.3 to 15.8 percent, respectively) than during the other five test periods (0 to 6.5 percent). The maximum decrease in mean spill for all other facilities was 5.6 percent. The mean overgeneration spill for the April through August period in 1993, 1998, and 2003 decreased from 606 average MW in the No Action case to 260 average MW under the Third AC alternative.

The changes in period average spill under the Maximum Capacity alternatives were similar to one another for each year. The mean spill decreases were noticeably higher in July at Ice Harbor and Lower Monumental dams (13.9 to 19.1 percent and 13.9 to 19.7 percent, respectively) than during the other five test periods (0 to 9.9 percent). The maximum decrease in mean spill for all other facilities was 6.2 percent. The mean overgeneration spill for the April through August period in 1993, 1998, and 2003 decreased from 606 average MW in the No Action case to 134 average MW in the Maximum Capacity case with the Proposed Formula Allocation and Assured Delivery.

Table 4.2.3-4

MAXIMUM DECREASE IN MEAN PERIOD AVERAGE TOTAL SPILL DUE TO INCREASED INTERTIE CAPACITY
(Percent)

Dam	Year	DC Alternatives						AC Alternative						Maximum Alternatives					
		April 1	April 2	May	June	July	Aug 1	April 1	April 2	May	June	July	Aug 1	April 1	April 2	May	June	July	Aug 1
Bonneville	1993	1.0	1.0	0.6	1.5	1.7	0.4	1.1	1.0	1.2	1.6	2.5	0.2	1.4	1.7	3.1	3.9	3.8	0.5
	1998	1.6	0.5	1.2	4.5	4.2	0.0	1.7	0.5	2.0	5.9	4.8	0.0	1.7	0.5	2.6	7.5	5.0	0.0
	2003	1.4	1.1	1.2	2.0	4.4	0.0	1.8	1.2	1.5	2.0	5.1	0.0	2.1	1.5	1.7	3.1	5.5	0.0
The Dalles	1993	2.1	1.7	0.7	2.7	2.6	0.0	2.4	2.2	1.6	3.4	4.1	0.0	2.8	3.0	7.0	7.1	4.5	0.0
	1998	1.9	4.0	4.2	3.0	5.1	0.0	2.3	4.4	4.3	5.0	5.6	0.0	2.5	4.7	7.6	9.8	6.2	0.0
	2003	1.5	0.9	4.1	5.8	4.1	0.0	1.7	2.1	5.8	6.5	5.1	0.0	2.6	3.1	8.8	8.9	6.0	0.0
John Day	1993	1.5	1.7	1.7	2.7	2.6	0.0	1.8	2.0	4.3	3.4	3.7	0.0	2.1	2.3	6.7	7.4	4.2	0.0
	1998	1.8	1.6	2.6	4.0	4.9	0.0	2.2	2.1	3.0	5.3	5.2	0.0	2.2	2.2	6.0	9.9	5.8	0.0
	2003	0.9	2.2	4.0	3.7	4.4	0.0	1.1	2.3	4.9	4.7	4.9	0.0	1.9	3.2	7.5	7.7	5.8	0.0
McNary	1993	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.1	0.0	0.0	0.0
	1998	0.0	0.2	0.1	0.0	0.2	0.0	0.2	0.1	0.1	0.0	0.2	0.0	0.2	0.2	0.2	0.0	0.1	0.0
	2003	0.0	0.7	0.3	0.1	0.1	0.0	0.0	0.8	0.1	0.1	0.1	0.0	0.0	0.9	0.3	0.1	0.1	0.0
Ice Harbor	1993	2.5	2.6	1.6	2.3	8.1	0.0	3.9	2.9	1.8	2.6	11.4	0.0	4.0	3.3	3.6	6.0	13.9	0.0
	1998	2.3	0.7	3.1	3.0	13.5	0.0	3.3	1.2	3.4	3.4	14.9	0.0	3.3	1.2	4.4	6.6	16.4	0.0
	2003	0.8	0.2	2.6	3.1	12.3	0.0	1.5	0.6	2.6	3.7	15.4	0.0	3.5	1.3	3.3	5.0	19.1	0.0
Lower Monumental	1993	2.7	2.8	1.7	2.8	8.0	0.0	3.0	3.0	1.9	3.1	11.3	0.0	4.3	3.6	4.8	6.9	13.9	0.0
	1998	3.0	1.6	3.7	3.4	13.6	0.0	4.1	2.1	4.9	4.8	15.6	0.0	4.4	2.1	6.3	9.1	17.1	0.0
	2003	1.2	0.6	3.5	3.8	12.8	0.0	1.6	1.0	3.8	5.1	15.8	0.0	3.8	2.1	6.4	7.9	19.7	0.0
Priest Rapids	1993	0.9	0.7	0.7	1.7	0.4	0.0	1.2	0.5	0.7	2.4	0.3	0.0	1.2	0.7	2.1	3.7	0.6	0.0
	1998	1.8	1.5	1.7	2.2	2.3	0.0	1.8	1.7	2.2	2.7	2.4	0.0	1.8	1.7	3.1	5.8	2.6	0.0
	2003	0.8	0.7	2.5	2.6	2.6	0.0	1.1	0.9	2.7	3.2	2.8	0.0	1.1	1.0	3.1	3.7	3.1	0.0
Wanapum	1993	0.5	0.4	0.0	0.5	0.0	0.0	0.8	0.0	0.0	0.4	0.0	0.0	0.9	0.6	0.2	0.9	0.0	0.1
	1998	1.7	0.8	1.4	1.3	1.1	0.0	1.7	0.7	1.5	1.6	1.3	0.0	1.7	0.8	1.7	2.2	1.6	0.0
	2003	0.4	1.0	0.7	0.8	1.3	0.0	0.9	1.2	0.6	0.7	1.3	0.0	0.9	1.4	0.8	0.8	1.4	0.0
Rock Island	1993	0.9	0.3	0.8	1.7	1.5	0.0	1.0	0.5	0.2	2.3	1.7	0.1	0.1	0.5	1.9	3.6	2.0	0.0
	1998	1.1	1.5	2.8	2.0	2.9	0.0	1.1	1.6	2.8	2.8	3.7	0.0	1.1	1.6	4.3	5.2	3.9	0.0
	2003	0.8	0.6	2.2	2.0	3.6	0.0	1.2	0.8	2.6	2.7	4.2	0.0	1.2	0.9	3.5	4.1	5.0	0.0
Rocky Reach	1993	0.9	0.6	0.6	1.2	1.3	0.0	1.1	0.8	0.4	1.7	1.8	0.0	1.1	1.0	1.9	2.9	1.9	0.0
	1998	1.2	1.7	2.3	1.6	2.5	0.0	1.2	2.1	2.4	2.3	2.8	0.0	1.2	2.1	3.5	4.7	3.0	0.0
	2003	0.7	0.6	1.9	2.1	2.5	0.0	1.1	0.7	2.3	2.6	2.9	0.0	1.1	1.4	3.5	3.5	3.4	0.0
Wells	1993	0.7	0.5	0.5	1.4	1.4	0.0	1.0	0.8	0.5	1.8	2.0	0.0	1.0	0.9	2.3	3.2	3.3	0.0
	1998	1.2	1.1	2.1	1.7	2.5	0.0	1.2	1.5	2.3	2.4	2.9	0.0	1.2	1.5	3.6	5.0	3.1	0.0
	2003	0.3	0.3	2.0	2.2	3.2	0.0	0.7	0.3	2.3	2.8	3.5	0.0	0.8	1.0	3.8	3.9	4.1	0.0

(WP-PG-1817Z)

Survival Changes: Analytical Methods

The analysis of downstream anadromous fish passage survival, as it may be affected by changes in spill and flows, was performed using a modified version of the Corps of Engineers' FISHPASS model. 1/

The major modifications to the Corps' version of the FISHPASS model involved expansion of the model to enable it to include the five Mid-Columbia Public Utility District dams, accept flow and spill data from the SAM model, and determine stock-specific system survival values in place of more aggregated output. Appendix E, Part 3 contains more detailed information on how the modified FISHPASS model was used in this analysis.

The modified FISHPASS model simulates downstream fish passage survival for anadromous fish passing the Lower Snake, Mid-Columbia, and Lower Columbia hydroprojects during the April through August period of downstream migration. Simulated flows and spills from the SAM were used as input to the FISHPASS model to calculate juvenile fish survival from the point of entry to the hydrosystem, to below Bonneville Dam. Survival projections were developed for stocks and species entering at specific projects (e.g., system survival to below Bonneville for yearling chinook salmon entering the river system at Lower Monumental pool).

The FISHPASS model simulates the project specific system survival for each of four separate classes of anadromous salmonids: yearlings, subyearlings, steelhead, and sockeye. The term "yearlings" designates spring chinook and Snake River summer chinook. The term "subyearlings" designates fall chinook and Mid-Columbia summer chinook. Yearlings are older than subyearlings and tend to be larger when they start their migration. Yearlings, steelhead, and sockeye tend to migrate in the spring (April, May, June) and subyearlings in the summer (June, July, August). The survival analysis was performed using SAM simulation data for period average flows and spill for the periods April 1-15, April 16-30, May, June, July, August 1-15, and August 16-31. The SAM data were analyzed with FISHPASS for the years 1988, 1993, 1998, and 2003 of the 20-year (1987 through 2006) SAM simulations (See Appendix B, Part 1, for a description of SAM).

For the IDU Final EIS, FISHPASS analyses use (1) the SAM simulated values of spills and the flows at each project; (2) the time, location, and number of hatchery and natural stocks of fish entering each pool; and (3) the project-specific characteristics for dam passage survival, pool survival, and travel time to simulate the downstream passage and project-specific survival for the April-through-August period of migration. The input parameters used in these analyses are the best available scientific data and believed to be the most likely values (see Appendix E, Part 3 for more information).

1/ A detailed description of the FISHPASS model is given in the Corps' model documentation titled "FISHPASS Model Concept and Applications," March 1986.

The FISHPASS model was run separately to calculate survival through the hydro system, to below Bonneville Dam, of those specific fish stocks and species entering the hydro system above each project. Individual runs were made for the stocks and species entering above Wells and Lower Granite dams, and into the pools of Rocky Reach, Rock Island, Lower Monumental, McNary, John Day, The Dalles, and Bonneville dams, and for the total system as a whole. The survival rates for the stocks of each pool are grouped in the categories of yearling, subyearling, steelhead, and sockeye. The survival values are applicable to both hatchery and natural stocks of fish within these categories since their time periods of migration and thus their river passage environment are assumed the same.

System stock survival calculations for each of the individual pools where stocks enter the river system, for each of the four categories of fish stocks, were made for 40 of the 200 SAM simulations for each of the 4 contract years (1988, 1993, 1998, and 2003) for each of the IDU alternatives studied. 1/ A paired comparison of the survival values for each stock between the No Action case and each IDU alternative was performed to obtain 40 relative changes in survival for each of the 4 years of analysis. Relative changes in survival, referred to throughout this section, were determined by taking the difference in survival between the alternative case and the No Action case and dividing the difference by the No Action case survival.

The following information on the survival to below Bonneville Dam of each category of fish stocks, for each pool of origin, was determined and is provided in Appendix E, Part 5, for each year of analysis and for each IDU alternative studied:

(1) The mean, median, maximum increase, and maximum decrease of the 40 relative changes in survival;
(2) the percent of the 40 relative survival increases and decreases exceeding one percent and five percent;
(3) The average over the study years for each of the statistics in (1) and (2) above;
(4) the mean, minimum, and maximum survival values;

1/ While certain information obtained from SAM (e.g., economics) required 200 simulations, the fish survival analyses, using the FISHPASS model, required only 40 random simulations of flow and spill data to provide adequate information on the impacts of IDU alternatives. The 40 simulations were also a reasonable and manageable number in light of the time and computer resources required for analyses. A random sample of 40 simulations provides a 90 percent confidence level that at least 91 percent of the population lies between the highest and lowest values of the sample of survival changes for that year of analysis (Somerville, 1985). Sensitivity analyses comparing FISHPASS survival changes for 40 versus 200 simulations show 40 simulations is an adequate sample for analyzing changes in survival between two alternatives (see Appendix E, Part 4).

(5) the relative change in the mean survival values;
(6) the change in the mean No Action case survival over time (1993, 1998, 2003) relative to the 1988 mean No Action case survival (i.e., changes in survival due to bypass improvements);
(7) the change in the mean IDU alternative case survival over time (1993, 1998, 2003) relative to the 1988 mean No Action case survival (i.e., changes in survival due to a combination of the bypass improvements and the IDU alternative); and
(8) the average over the years 1993, 1998, and 2003 for each of (5), (6), and (7) above.

To ensure that all fish stocks potentially affected by an operational change at the Federal and Mid-Columbia PUD hydroelectric projects were considered in the analysis, the following steps were undertaken:

(1) All anadromous fish stocks in the Columbia Basin which might be affected were identified (see Appendix E, Part 7 for the list of fish stocks, by pool, considered in the analysis).

(2) An evaluation was made to identify potentially critical stocks based upon the biological viability and harvest management of each stock. Critical stocks are those which are substantially below escapement goals, are not increasing on a clear trend (biological viability is potentially jeopardized), and for which harvest and production management actions reflect the stock's critical condition.

(3) Flagging criteria, described below, were applied to all stocks not identified as critical in step 2. Any of the stocks not identified as critical by step 2 and not flagged by the criteria, were assumed to be free from significant effect.

(4) The critical stocks identified in step 2, and any additional stocks flagged by application of the criteria in step 3, were subject to additional analyses for significance. The significance analysis took into consideration current stock status, harvest management implications, recent and expected improvements in system survival due to implementation of fish passage measures, and other efforts to increase stocks to achieve the purposes of the Northwest Power Act.

The 40 relative changes in fish survival between the No Action case and each test case for each of the 4 contract years were analyzed. The flagging criteria mentioned above were designed to identify fish stocks that showed levels of impact high enough to warrant further examination. The flagging criteria were selected by a professional fisheries biometrician (L. Mobrand, 1986) under BPA contract, and were based on his review of survival data and analysis of stock recruitment relationships. The "flagging" criteria were: (a) mean or median relative decrease in survival of greater than 1 percent (calculated over 40 simulations); (b) relative decrease in survival greater than 5 percent in more than 5 percent of the 40 simulations; and (c) relative decrease in survival greater than 1 percent in more than 30 percent of the 40 simulations.

The mean and median survival impacts represent the expected effect in any future year and also the effect over the long term. Changes in survival of greater than 1 percent and 5 percent were examined to give an understanding of the distribution of survival changes. By themselves, these criteria do not indicate significant impact to any of the Columbia Basin's fish stocks. Instead, they were used to indicate a need for more detailed analyses on those specific stocks to determine significance.

For stocks identified as potentially critical, and noncritical stocks exceeding the flagging criteria, analyses were undertaken of the viability of each stock as indicated by the most recent stock assessment data and mitigation actions being implemented for the stock. The analysis of biological significance considered the trend and anticipated duration of the simulated impact to the stock. The stocks were examined for their biological viability and whether they were sufficiently productive to allow harvest. The severity of simulated adverse impact was compared, when possible, to the magnitude of positive effects of past, present, and planned mitigation measures as described in the Columbia River Basin Fish and Wildlife Program. The importance of the simulated impact and affected stock relative to the management regime set by State, Federal, and Tribal fishery management authorities was also considered.

It is assumed a significant impact would occur if fish passage survival through the hydro system were reduced such that:

(a) Rehabilitation of a stock that is not currently harvestable or viable would be adversely affected to any degree;

(b) recent and projected improvements in the run and escapement of a presently viable, but unharvestable stock would be significantly delayed;

(c) the harvest rate or pattern of a presently harvestable and viable stock would be significantly reduced or altered; or

(d) rehabilitation of a presently harvestable and viable stock would be substantially delayed or a significant portion of the harvestable surplus would be eliminated.

Additional information on the effects of increased capacity on changes in survival can be found in Appendix E, Part 5.

Sensitivity Analyses. The FISHPASS model results are dependent on several input variables for downstream fish passage conditions at hydroelectric projects. These variables have a certain amount of uncertainty associated with the biological variability and experimental precision of the empirical data from which they were derived. The simulated changes in fish survival are also dependent on economic assumptions used in the SAM, 1/ which affect the operation of the

1/ A description of the SAM sensitivity analyses appears in Appendix B, Part 6.

hydroelectric system. Additionally, assumptions about future construction of fish bypass systems, and improvements at existing systems, affect both the changes in fish survival and the context in which those changes are being viewed.

Several sensitivity analyses were performed to test the variability of the comparative results from the FISHPASS model associated with the uncertainty of key input values. These analyses looked at how the values of the input variable affected the change in survival for the Proposed Formula Allocation, Existing Contracts, Maximum Capacity test alternative relative to the No Action test alternative. This test alternative was chosen since it is projected to have the greatest impact on fish. The FISHPASS model simulated the changes in survival for this comparison assuming different input values for each sensitivity test. The effect of uncertainty associated with the specific variable being tested can be evaluated by comparing the changes in survival under the most expected conditions to the changes in survival under the sensitivity test conditions. In addition, analyses were undertaken of the difference between 1988 survival and survival in later years under the No Action test cases in order to evaluate how input values might alter the context within which study results are being interpreted.

The following survival information for each sensitivity variable tested is provided in Appendix E, Part 6, for each fish stock and year of analysis:

1. The mean survival for the No Action case.

2. The mean survival for the sensitivity test case.

3. The relative change in mean survival between the test alternative and the No Action case.

4. The change in the No Action case survival over time relative to the 1988 No Action case survival.

5. The change in the alternative case survival over time relative to the 1988 No Action case survival.

6. The average of the years 1993, 1998, and 2003 for each of the above statistics (1988 is not included in this average since the Intertie expansions would take place after this year).

The sensitivity analyses were grouped into three categories: (1) FISHPASS Model Parameters; (2) Fish Bypass Assumptions; and (3) SAM Input Assumptions.

For the FISHPASS Model Parameters, the sensitivity analyses tested the key input values having the most effect on FISHPASS results. The following sensitivity tests were performed for which the results are given in Table 4.2.3-5 for the average of 1993, 1998, and 2003 relative changes in mean survival for each stock (Appendix E, Part 6 provides data for each year):

1. Reservoir Mortality: Assumed reservoir mortality was decreased and increased by 50 percent for all hydro projects.

2. Spill Efficiency: The assumed efficiency of spill for passing fish around turbines and collection/bypass systems was decreased and increased by 50 percent at all hydro projects.

3. Turbine Mortality: Assumed turbine mortality was decreased and increased by 25 percent at all projects.

4. Subyearling Reservoir Mortality: A constant subyearling reservoir mortality was assumed for all projects (i.e., 10 percent at Rock Island, Priest Rapids, Little Goose, Lower Monumental, Ice Harbor, and The Dalles; 15 percent at Rocky Reach, Wanapum, McNary, and Bonneville; and 20 percent at John Day). This test addressed the uncertainty as to whether subyearlings have a flow-dependent reservoir mortality rate as is currently modeled.

5. Transportation Survival: The survival of all transported fish was decreased by 50 percent (i.e., Lower Granite and Little Goose was reduced from 95 percent to 48 percent survival and McNary from 99 percent to 50 percent survival). This test addresses the uncertainty related to potential differences in post-Bonneville survival of transported and nontransported fish, by assuming that nontransported fish have a much greater post-Bonneville survival.

6. Fish Guidance Efficiency: Assumed fish guidance efficiencies, both current and future projected, were decreased and increased by 25 percent at all hydro projects.

These sensitivity analyses show that the assumptions for FISHPASS input parameters have only minor effects on the difference in survival between the No Action alternative and the test case alternative. The largest change in impacts occurred for Lower Monumental subyearlings with the fish guidance efficiency changes. The relative decrease in survival for this stock changed from 3.3 percent under the expected conditions to 4.5 percent and 2.2 percent under low and high fish guidance efficiencies, respectively. All other FISHPASS parameter variables changed the average relative survival impacts less than 1 percent for all stocks.

Analyses of how the assumptions for FISHPASS model parameters effect the projected improvements in fish passage survival, shows that future increases in survival are most affected by the assumptions of low fish guidance efficiencies achieved at the projects and low levels of transportation survival. These factors are taken into account when evaluating the significance of the results described in the following section of the fish analysis. Other FISHPASS parameter assumptions have only minor effects on the projected survival increases.

Table 4.2.3-5

EFFECTS OF FISHPASS ASSUMPTIONS ON IMPACTS 1/

Pool	Stock	Original Assumptions	Reservoir Mortality Low	Reservoir Mortality High	Spill Efficiency Low	Spill Efficiency High	Turbine Mortality Low	Turbine Mortality High	Constant Subyearling Reservoir Mortality	Transportation Survival	Fish Guidance Efficiency Low	Fish Guidance Efficiency High
Wells	Yearling	-1.3	-1.4	-1.2	-0.6	-1.6	-1.0	-1.6	-1.3	-1.9	-2.2	-0.7
	Subyearling	-2.4	-2.2	-2.7	-1.2	-3.0	-1.8	-3.0	-1.8	-2.9	-3.4	-1.7
	Steelhead	-1.0	-1.0	-1.0	-0.5	-1.2	-0.8	-1.2	-1.0	-1.3	-1.7	-0.5
	Sockeye	-1.8	-1.9	-1.8	-0.9	-2.3	-1.4	-2.3	-1.8	-2.3	-2.5	-1.3
Rocky Reach	Yearling	-0.4	-0.5	-0.2	-0.0	-0.5	-0.2	-0.5	-0.4	-0.9	-0.9	-0.0
	Subyearling	-1.7	-1.8	-1.5	-0.7	-2.2	-1.2	-2.1	-1.5	-2.1	-2.3	-1.1
	Steelhead	-0.6	-0.6	-0.6	-0.3	-0.7	-0.4	-0.7	-0.6	-0.8	-1.1	-0.3
	Sockeye	-	-	-	-	-	-	-	-	-	-	-
Rock Island	Yearling	-0.3	-0.5	-0.2	-0.0	-0.4	-0.2	-0.5	-0.3	-0.9	-0.9	-0.0
	Subyearling	-1.0	-1.0	-0.9	-0.4	-1.3	-0.7	-1.3	-0.9	-1.4	-1.5	-0.6
	Steelhead	-0.2	-0.3	-0.2	-0.1	-0.3	-0.1	-0.3	-0.2	-0.5	-0.6	-0.1
	Sockeye	-0.9	-0.9	-0.8	-0.4	-1.2	-0.6	-1.1	-0.9	-1.2	-1.4	-0.6
Lower Granite	Yearling	-0.0	-0.1	-0.0	-0.0	-0.1	-0.0	-0.0	-0.0	-0.1	-0.2	-0.0
	Subyearling	-0.3	-0.5	-0.2	-0.1	-0.4	-0.3	-0.4	-0.4	-0.5	-0.6	-0.1
	Steelhead	-0.0	-0.0	-0.0	-0.0	-0.0	-0.0	-0.0	-0.0	-0.0	-0.1	-0.0
	Sockeye	-0.3	-0.4	-0.2	-0.1	-0.4	-0.2	-0.3	-0.3	-0.5	-0.4	-0.1
Lower Monumental	Yearling	-0.8	-0.8	-0.8	-0.3	-1.0	-0.6	-1.1	-0.8	-1.2	-1.7	-0.2
	Subyearling	-3.3	-3.0	-3.4	-1.5	-4.0	-2.3	-4.2	-2.4	-3.9	-4.5	-2.2
	Steelhead	-0.4	-0.4	-0.4	-0.2	-0.5	-0.3	-0.5	-0.4	-0.7	-1.2	0.0
	Sockeye	-	-	-	-	-	-	-	-	-	-	-
McNary	Yearling	-0.2	-0.3	-0.1	0.0	-0.3	-0.1	-0.3	-0.2	-0.7	-0.6	0.0
	Subyearling	-0.8	-0.9	-0.8	-0.4	-1.0	-0.6	-1.0	-0.7	-1.2	-1.3	-0.5
	Steelhead	-0.1	-0.2	-0.1	-0.0	-0.1	-0.0	-0.1	-0.1	-0.3	-0.4	0.0
	Sockeye	-	-	-	-	-	-	-	-	-	-	-
John Day	Yearling	-0.6	-0.6	-0.7	-0.3	-0.8	-0.5	-0.8	-0.6	-0.6	-1.1	-0.3
	Subyearling	-2.2	-2.1	-2.3	-1.1	-2.4	-1.5	-2.9	-2.0	-2.2	-2.9	-1.6
	Steelhead	-0.8	-0.8	-0.9	-0.4	-0.9	-0.6	-1.1	-0.8	-0.8	-1.7	-0.2
	Sockeye	-	-	-	-	-	-	-	-	-	-	-
The Dalles	Yearling	-0.5	-0.4	-0.6	-0.3	-0.6	-0.4	-0.6	-0.5	-0.5	-0.8	-0.3
	Subyearling	-0.6	-0.5	-0.7	-0.3	-0.7	-0.4	-0.8	-0.5	-0.6	-1.0	-0.3
	Steelhead	-0.5	-0.5	-0.6	-0.3	-0.6	-0.4	-0.7	-0.5	-0.5	-0.9	-0.3
	Sockeye	-	-	-	-	-	-	-	-	-	-	-

Table 4.2.3-5 (Continued)

Pool	Stock	Original Assumptions	Reservoir Mortality		Spill Efficiency		Turbine Mortality		Constant Subyearling Reservoir Mortality	Transportation Survival	Fish Guidance Efficiency	
			Low	High	Low	High	Low	High			Low	High
Bonneville	Yearling	-0.2	-0.2	-0.2	-0.1	-0.2	-0.1	-0.2	-0.2	-0.2	-0.3	-0.1
	Subyearling	-0.2	-0.2	-0.3	-0.1	-0.3	-0.2	-0.3	-0.2	-0.2	-0.3	-0.2
	Steelhead	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.1	-0.1	-0.2	-0.1
	Sockeye	-	-	-	-	-	-	-	-	-	-	-
Columbia System	Yearling	-0.2	-0.3	-0.2	-0.1	-0.3	-0.2	-0.3	-0.2	-0.3	-0.4	-0.1
	Subyearling	-0.7	-0.8	-0.7	-0.3	-0.9	-0.5	-0.9	-0.6	-0.8	-1.0	-0.5
	Steelhead	-0.2	-0.2	-0.1	-0.1	-0.2	-0.1	-0.2	-0.2	-0.2	-0.4	-0.1
	Sockeye	-	-	-	-	-	-	-	-	-	-	-

1/ The impacts in this table represent the difference in relative survival of downstream migrants when moving from the No Action case to the Maximum Capacity, Proposed Formula Allocation, Existing Contracts test case. "-" indicates not applicable or not available.

While the FISHPASS input parameters can have substantial effects on the survival simulated for any given alternative, the effect is greatly reduced in comparative analyses looking at changes in survival between two alternatives. The type of comparative analysis used in the IDU EIS is not dependent on highly accurate simulations of fish survival, since errors associated with the uncertainty of the input data are to a large degree cancelled out by making the same assumptions for these input parameters in the two alternatives being compared. Therefore, much of the uncertainty of the FISHPASS model parameters is not critical to the study results for changes in survival associated with the IDU alternatives.

The sensitivity studies for Fish Bypass Assumptions tested the following pessimistic assumptions:

1. An assumption of a 3-year delay in the addition of new fish bypass systems and the improvements of existing systems for all hydro projects.

2. An assumption of no new fish bypass systems at The Dalles and Ice Harbor.

3. An assumption of no new fish bypass systems at The Dalles, Ice Harbor, and Lower Monumental.

4. An assumption of no additional new fish bypass systems and no improvements of existing systems for all hydro projects.

Studies (1) and (4) above affect the future fish bypass conditions for Wells, Rocky Reach, Rock Island, Wanapum, Priest Rapids, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, The Dalles, and the Bonneville second powerhouse. The bypass systems at John Day and Bonneville first powerhouse are not affected since there are currently no improvements planned at these projects.

The results of these sensitivity analyses are given in Appendix E, Part 6. The results show bypass assumptions have little effect on the difference in the fish impacts between the No Action case and the sensitivity test case. However, the change in the No Action case survival over time due to bypass improvement is greatly affected by these assumptions. Thus, the context within which the impacts of the IDU alternatives are being assessed is highly dependent on future levels of fish bypass improvements. Table 4.2.3-6 shows how bypass assumptions would affect both the average difference (for years 1993, 1998, and 2003) between survival under the No Action case and the test case and the difference between 1988 and 2003 survival levels in the No Action case.

The sensitivity studies for the SAM Input Assumptions are described in Appendix B, Part 7. These studies tested the following variables, which initial screening showed might have the potential for increased fish impacts:

1. California high gas price

2. California high loads

3. Pacific Northwest low loads

4. New nonfirm rate cap

5. Seasonal exchange level

These studies show that there is no substantial change in the level of fish impacts under the different SAM assumptions, and the conclusions about the significance of the fish impacts of the alternative Intertie decisions studied are not affected by these assumptions. The results of these sensitivity studies are given in Appendix E, Part 6.

Survival Changes: Results

The following sections describe relative differences between the No Action case and the test scenarios previously summarized in Table 4.2.3-1 with regard to survival of downstream juvenile migrants. Full results of these analyses are presented in Appendix E, Part 5. Because of the importance of bypass improvements in defining the context in which the significance of the projected effects is interpreted (see Appendix E, Part 6) the effects are evaluated both with and without assumed future fish passage improvements. The effects of current stock management programs and the biological status of critical or flagged stocks are also taken into account in evaluating the potential significance of projected impacts (see Appendix E, Part 7).

Effects of Formula Allocation Options

Both the Proposed and Hydro-First formula allocation options have negligible effects on downstream migrant survival of juvenile fish. Smolt passage survival through the hydroelectric system improves slightly (mean relative changes in survival increased up to 0.8 percent for the Proposed formula allocation and up to 0.9 percent for the Hydro-First option) for some fish stocks in certain study years. Most anadromous fish stocks also have years in which their downstream survivals are impacted negatively by a few tenths of a percent (up to 0.5 percent for either formula allocation option). The single year maximum increase and decrease for any simulation for any contract year for either allocation option was 17 percent and 10 percent, respectively.

Overall, these impacts are minor relative to each stock's current population and productivity status, current smolt passage survival, and expected increase in passage survival due to planned improvements in fish passage facilities. No significant effects to anadromous fish passage would be expected to result from implementation of either of the formula allocation options. This would continue to be BPA's conclusion even if planned fish passage improvements are not implemented.

Table 4.2.3-6

EFFECT OF BYPASS ASSUMPTIONS ON IMPACTS TO ANADROMOUS FISH AND GAINS IN FUTURE SURVIVAL 1/

		Bypass Assumptions									
		As Planned		3-Year Delay		None at The Dalles and Ice Harbor		None at The Dalles, Ice Harbor and Lower Monumental		No Additional Passage Improvements	
Pool	Stock	Impacts	Gains	Impacts	Gains	Impacts	Gains	Impacts	Gains	Impacts	Gains
Wells	Yearling	-1.3	35.5	-1.4	30.8	-1.3	34.3	-1.4	34.2	-1.9	0.3
	Subyearling	-2.4	61.7	-2.4	57.7	-2.5	60.8	-2.5	60.7	-3.9	10.9
	Steelhead	-1.0	38.4	-1.0	33.8	-1.0	37.7	-0.9	37.6	-1.7	-1.0
	Sockeye	-1.8	33.7	-1.9	30.3	-1.8	32.3	-1.8	32.2	-2.4	-2.2
Rocky Reach	Yearling	-0.4	37.1	-0.4	32.4	-0.5	36.1	-0.6	36.2	-0.8	0.9
	Subyearling	-1.7	30.7	-1.8	27.4	-1.8	29.6	-1.8	29.6	-2.7	1.0
	Steelhead	-0.6	26.6	-0.6	22.4	-0.6	25.9	-0.6	25.8	-1.3	-1.3
	Sockeye	-	-	-	-	-	-	-	-	-	-
Rock Island	Yearling	-0.3	22.7	-0.4	22.3	-0.4	21.8	-0.5	21.9	-0.7	1.0
	Subyearling	-1.0	34.3	-1.0	33.9	-1.1	33.5	-1.1	33.4	-1.4	6.5
	Steelhead	-0.2	22.4	-0.2	22.1	-0.3	21.8	-0.2	21.8	-0.5	-0.1
	Sockeye	-0.9	22.3	-0.9	21.7	-0.9	21.2	-0.9	21.1	-1.3	-2.5
Lower Granite	Yearling	-0.0	22.4	-0.1	22.2	-0.1	22.1	-0.1	22.0	-0.2	0.0
	Subyearling	-0.3	2.3	-0.3	2.2	-0.4	2.1	-0.4	2.0	-0.4	1.3
	Steelhead	-0.0	5.6	-0.0	5.6	0.0	5.5	0.0	5.5	-0.1	-0.2
	Sockeye	-0.3	1.3	-0.3	1.2	-0.3	0.9	-0.4	0.9	-0.4	-0.7
Lower Monumental	Yearling	-0.8	12.7	-1.1	9.2	-1.1	6.9	-1.9	2.1	-1.7	-2.8
	Subyearling	-3.3	20.9	-3.6	19.7	-3.7	17.5	-4.4	17.2	-4.8	7.2
	Steelhead	-0.4	11.7	-0.7	7.9	-0.7	6.0	-1.5	0.2	-1.4	-4.0
	Sockeye	-	-	-	-	-	-	-	-	-	-
McNary	Yearling	-0.2	7.7	-0.3	7.4	-0.3	7.1	-0.3	7.0	-0.4	1.5
	Subyearling	-0.8	17.8	-0.9	17.5	-0.9	17.1	-0.9	17.1	-1.1	4.3
	Steelhead	-0.1	5.1	-0.1	4.9	-0.1	4.6	-0.1	4.6	-0.2	0.2
	Sockeye	-	-	-	-	-	-	-	-	-	-
John Day	Yearling	-0.6	2.6	-0.8	0.9	-0.9	-0.8	-0.8	-0.9	-0.9	-0.5
	Subyearling	-2.2	1.0	-2.5	0.0	-2.6	-1.2	-2.6	-1.3	-2.5	-0.1
	Steelhead	-0.8	2.6	-1.1	1.0	-1.3	-0.6	-1.3	-0.7	-1.3	0.0
	Sockeye	-	-	-	-	-	-	-	-	-	-
The Dalles	Yearling	-0.5	6.0	-0.7	4.2	-0.8	2.2	-0.8	2.1	-0.8	-1.9
	Subyearling	-0.6	6.2	-0.7	4.8	-0.8	3.4	-0.8	3.4	-0.7	4.2
	Steelhead	-0.5	-3.5	-0.8	1.8	-0.9	-0.1	-0.9	-0.1	-0.9	0.3
	Sockeye	-	-	-	-	-	-	-	-	-	-

Table 4.2.3-6 (Continued)

		Bypass Assumptions									
		As Planned		3-Year Delay		None at The Dalles and Ice Harbor		None at The Dalles, Ice Harbor and Lower Monumental		No Additional Passage Improvements	
Pool	Stock	Impacts	Gains	Impacts	Gains	Impacts	Gains	Impacts	Gains	Impacts	Gains
Bonneville	Yearling	-0.2	0.1	-0.2	0.1	-0.2	0.1	-0.2	0.1	-0.2	0.1
	Subyearling	-0.2	0.3	-0.2	0.3	-0.2	0.3	-0.2	0.3	-0.2	0.9
	Steelhead	-0.1	-0.7	-0.1	-0.7	-0.1	-0.7	-0.1	-0.7	-0.2	-0.1
	Sockeye	-	-	-	-	-	-	-	-	-	-
Columbia System	Yearling	-0.2	10.0	-0.2	9.5	-0.3	9.6	-0.3	9.5	-0.4	0.3
	Subyearling	-0.7	9.2	-0.8	8.8	-0.8	8.6	-0.8	8.6	-0.9	2.4
	Steelhead	-0.2	6.1	-0.2	5.6	-0.2	5.5	-0.2	5.4	-0.3	-0.3
	Sockeye	-	-	-	-	-	-	-	-	-	-

1/ The impacts shown in this table are the percent changes (averaged over 1993, 1998, and 2003) in relative survival when moving from the No Action case to a test case consisting of Maximum Capacity, Proposed Formula Allocation, and Existing Firm Contracts. The gains in future survival represent the difference between projected survival for 1988 versus 2003 in the No Action case. "-" indicates not applicable or not available.

Effects of Long-term Firm Contracts

The mean relative changes in survival for all stocks, in all years, under the Federal Marketing options ranged from a maximum increase of 1.8 percent to a maximum decrease of 0.4 percent. For the Assured Delivery options, mean relative changes in survival ranged from a maximum increase of 3.4 percent to a maximum decrease of 0.8 percent.

Single year maximum increases in stock survival for cases including the Federal Marketing option were 16, 24, 6, and 9 percent for, respectively, yearlings, subyearlings, steelhead and sockeye. Comparable figures for the Assured Delivery option cases were 16, 15, 6, and 10 percent, respectively. Similarly, maximum decreases for Federal Market were 15, 9, 5, and 6 percent, respectively, and for Assured Delivery 24, 9, 8, and 6 percent, respectively.

Although the effects of the Federal Marketing and Assured Delivery contract options would be minor, they would be slightly greater than for the formula allocation options. Overall, these effects are minor relative to each stock's current population and productivity status, current smolt passage survival, and expected increase in passage survival due to planned improvements in fish passage facilities. Given planned bypass improvements, no significant effects to anadromous fish passage would be expected to result from implementation of either of these contract options. However, sensitivity analyses do indicate that failure to construct the planned Mid-Columbia bypass systems could alter this conclusion for Methow River spring chinook.

Effects of Increasing Intertie Capacity 1/

Tables 4.2.3-7, 4.2.3-8, and 4.2.3-9 summarize the range of average and maximum single year relative survival changes for 1993, 1998, and 2003 for the DC Upgrade, Third AC, and Maximum Capacity alternatives.

The analysis of survival changes under the DC Upgrade alternative for all stocks shows projected average relative changes in survival for yearlings, subyearlings, and steelhead ranged, respectively, from increases of 0.7, 0.1, and 0.2 percent to decrease of 1.4, 1.4 and 0.9 percent. There were no increases in sockeye stocks. Effects on sockeye ranged from zero to a decrease of 1.1 percent. Maximum single year increases for the respective stock types were 15, 11, 6, and 10 percent whereas maximum decreases were 16, 9, 7, and 7 percent, respectively.

Under the Third AC alternative, the average relative survival changes for yearlings, subyearlings, and steelhead would range from increase of 0.6, 0.4, and 0.1 percent to decreases of 1.4, 1.6, and 0.9 percent. Effects on sockeye survival ranged from no effect to a decrease of 1.2 percent. Maximum single year changes ranged from increases of 16, 11, 6, and 10 percent to decreases of 12, 11, 9, and 7 percent.

1/ Contract year 1988 was not included in this section since Intertie capacity upgrades do not occur until after this year.

Under the Maximum Capacity alternatives, average relative survival changes for yearlings, subyearlings, steelhead, and sockeye ranged, respectively, from increase of 0.4, a decrease of 0.1, no effect, and no effect to decreases of 2.0, 2.9, 1.3, and 2.0 percent. Maximum single year changes ranged from increases of 16, 13, 6, and 10 percent to maximum decreases of 16, 13, 9, and 11 percent.

Table 4.2.3-7

RANGE OF THE AVERAGE AND THE MAXIMUM SINGLE YEAR RELATIVE CHANGES IN SURVIVAL % FOR 1993, 1998, 2003 FOR THE DC UPGRADE ALTERNATIVES *

	Yearling		Subyearling		Steelhead		Sockeye	
Pool	Range of Average Changes	Maximum Increase/ Decrease	Range of Average Changes	Maximum Increase/ Decrease	Range of Average Changes	Maximum Increase/ Decrease	Range of Average Changes	Maximum Increase/ Decrease
Wells	-0.4/-1.1	5/7	-0.1/-1.4	10/8	-0.4/-0.7	5/5	-0.7/-1.1	7/7
Rocky Reach	0.7/-0.9	16/15	0.1/-0.8	11/9	-0.3/-0.5	3/5	0/0	0/0
Rock Island	0.5/-1.0	15/12	0.1/-0.5	7/4	0.1/-0.5	6/6	-0.3/-0.7	10/7
Lower Granite	0/-0.1	0/1	-0.1/-0.2	1/1	0/ 0	0/0	-0.1/-0.2	0/1
Lower Monumental	0/-0.9	6/5	-0.7/-1.2	4/9	0.1/-0.6	3/5	0/0	0/0
McNary	0/-1.0	9/10	-0.2/-0.4	3/2	0.2/-0.4	4/4	0/0	0/0
John Day	0.1/-1.4	8/11	-0.1/-1.0	10/8	-0.1/-0.6	5/4	0/0	0/0
The Dalles	0.2/-1.3	9/16	-0.1/-0.4	4/3	0/-0.9	4/7	0/0	0/0
Bonneville	0/-0.4	2/4	0/-0.6	3/6	0/-0.5	2/4	0/0	0/0
Total System	0/-0.5	3/5	-0.2/-0.5	2/3	0/-0.2	1/2	-0.2/-0.4	2/2

* Changes are relative to the No Action Alternative based on averages and maximums for the 40 simulations of each year of analysis.

Increases in Intertie capacity would have more adverse effect upon anadromous fish survival than would either the formula allocation or firm contracts options. However, even these effects are small and would not be expected to be significant, provided planned fish passage improvements are made. Clearly, the adverse effects of the Third AC are slightly larger than those for the DC Upgrade, with Maximum Capacity producing the largest effect.

For John Day fall chinook, bypass installation at the Dalles Dam is expected to increase survival only 1.9 percent. Transportation of fish from John Day Dam could also be used to enhance this stock as an alternative to installation of additional bypass at The Dalles. Survival increases that could result from initiating fish transportation from John Day Dam were not analyzed. The status of this chinook population is not known, but is thought to be very low. Since survival of this stock could decrease by about 1 percent due to the Third AC, and by as much as 2 percent under Maximum capacity (see Appendix E, Part 5), what little improvement would otherwise be expected in the survival of this stock

Table 4.2.3-8

RANGE OF THE AVERAGE AND THE MAXIMUM SINGLE YEAR RELATIVE CHANGES IN SURVIVAL %
FOR 1993, 1998, 2003 FOR THE THIRD AC ALTERNATIVE*

	Yearling		Subyearling		Steelhead		Sockeye	
Pool	Range of Average Changes	Maximum Increase/ Decrease	Range of Average Changes	Maximum Increase/ Decrease	Range of Average Changes	Maximum Increase/ Decrease	Range of Average Changes	Maximum Increase/ Decrease
Wells	-0.8/-1.4	4/6	-0.5/-1.5	7/10	-0.6/-0.9	5/7	-1.1/-1.2	7/7
Rocky Reach	0.6/-1.2	16/12	-0.4/-0.7	11/7	-0.4/-0.6	3/5	0/0	0/0
Rock Island	0.5/-1.3	14/10	-0.2/-0.5	6/7	0/-0.4	6/8	-0.5/-0.8	10/6
Lower Granite	0/-0.1	1/1	-0.2/-0.2	0/1	0/ 0	0/0	-0.2/-0.2	0/1
Lower Monumental	-0.2/-1.4	4/7	-1.3/-1.6	4/11	0/-0.8	4/9	0/0	0/0
McNary	0/-1.0	9/10	0.4/-0.6	2/3	0.1/-0.5	3/8	0/0	0/0
John Day	0/-1.1	7/11	-0.9/-1.1	8/6	-0.3/-0.7	4/3	0/0	0/0
The Dalles	0.2/-1.0	8/9	-0.3/-0.5	1/3	-0.1/-0.8	4/5	0/0	0/0
Bonneville	-0.1/-0.4	2/3	-0.1/-0.5	2/4	0/-0.4	2/3	0/0	0/0
Total System	0/-0.5	3/3	-0.3/-0.6	2/3	0/-0.3	1/2	-0.4/-0.4	2/2

* Changes are relative to the No Action Alternative based on averages and maximums for the 40 simulations of each year of analysis.

Table 4.2.3-9

RANGE OF THE AVERAGE AND THE MAXIMUM SINGLE YEAR RELATIVE CHANGES IN SURVIVAL %
FOR 1993, 1998, 2003 FOR THE MAXIMUM CAPACITY ALTERNATIVES*

	Yearling		Subyearling		Steelhead		Sockeye	
Pool	Range of Average Changes	Maximum Increase/ Decrease	Range of Average Changes	Maximum Increase/ Decrease	Range of Average Changes	Maximum Increase/ Decrease	Range of Average Changes	Maximum Increase/ Decrease
Wells	-1.2/-2.0	5/12	-0.7/-2.2	10/10	-0.8/ 1.2	4/8	-1.6/-2.0	7/11
Rocky Reach	0.1/-1.4	16/16	-0.7/-1.9	13/8	-0.5/-0.9	3/6	0/0	0/0
Rock Island	0.4/-1.4	15/14	-0.2/-1.0	7/7	0/ 0.7	6/8	-0.7/-1.3	10/7
Lower Granite	0/-0.1	1/1	-0.2/-0.4	1/2	0/ 0	0/0	-0.2/-0.3	0/2
Lower Monumental	-0.1/-1.7	6/8	-1.9/-2.9	4/13	0/-1.0	5/9	0/0	0/0
McNary	0.4/-1.4	9/11	-0.5/-1.0	3/5	0.3/-0.7	5/8	0/0	0/0
John Day	0/-1.7	7/13	-1.2/-2.3	10/10	-0.3/-1.3	5/5	0/0	0/0
The Dalles	0.2/-1.6	8/16	-0.4/-1.0	3/3	-0.2/-1.3	3/8	0/0	0/0
Bonneville	-0.1/-0.5	1/4	-0.1/-0.7	2/7	0/-0.6	1/4	0/0	0/0
Total System	0/0.7	3/6	-0.5/-0.9	2/7	-0.1/-0.4	1/3	-0.5/-0.7	2/4

* Changes are relative to the No Action Alternative based on averages and maximums for the 40 simulations of each year of analysis.

could be substantially or totally eliminated by choice of these capacity options. Insufficient data are available to judge whether the effects of these options would significantly affect this stock's current productivity. However, effects of this magnitude would not be significant relative to the harvest and production policies applied to this stock.

If planned passage improvements are not implemented, even the relatively small adverse effects of increased capacity could become significant for a number of stocks.

All potentially critical stocks of spring and summer chinook and steelhead spawning in the Snake River Basin above Lower Granite Dam could be significantly impacted by Maximum Capacity if planned bypass upgrades at Lower Granite and Little Goose dams are not completed.

If bypass is not installed at Lower Monumental Dam or upgrades are not made to bypass at McNary, Tucannon River spring chinook and Lyons Ferry fall chinook could be significantly impacted by any of the expanded capacity options. The McNary upgrades are also necessary to prevent the expanded capacity options from significantly impacting Yakima spring chinook. Either the Third AC or Maximum Capacity options could jeopardize both The Tucannon River and Lyons Ferry Hatchery summer steelhead stocks in the absence of the McNary upgrades. In addition, Maximum Capacity would significantly impact these two steelhead stocks without the Lower Monumental bypass.

All stocks of Mid-Columbia anadromous fish originating above Rock Island Dam could be significantly affected by any of the increased capacity options if planned bypass systems are not installed at Mid-Columbia Dams.

Failure to complete the McNary upgrade, could delay improvements to steelhead stocks originating in the McNary pool. If the bypass system currently planned for the Dalles Dam is not installed, or other alternative passage actions such as transportation from John Day Dam are not implemented, both John Day spring chinook and Umatilla summer steelhead could be significantly impacted by any of the expanded capacity options. In addition, without these passage improvements, Maximum Capacity could cause significant impacts to the Deschutes and Warm Spring spring chinook. Effects of Maximum Capacity on Deschutes fall chinook would not be significant due to the effects of the overriding harvest management policies applied to this stock.

The effects of bypass assumptions on the significance of the impact of Intertie decisions to Columbia and Snake River anadromous fish stocks is summarized in Table 4.2.3-10.

4.2.3.4.2 Hanford Reach Spawning and Emergence Flows

Issues

The 54-mile free-flowing section of the Columbia River from Priest Rapids Dam through the Hanford Reach is valuable to natural production of fall chinook salmon and steelhead. Significant declines in production occurred through the 1970s. The Hanford Reach is sensitive to higher flows in the fall which may permit adult fish to gain access to areas of the river bed that may not be covered by flows during the subsequent spring period when fry are due to emerge. To address this problem, a 1984-85 interim Vernita Bar FERC Settlement Agreement between fishery agencies, Tribes, and the Grant County Public Utility District specified flows to protect the natural production of fall chinook salmon from spawning through emergence. Negotiations between BPA, fishery entities and the Mid-Columbia PUDs are underway to establish a long-term FERC Settlement Agreement. This agreement is currently being ratified. Under the long-term Agreement, the magnitude and duration of maximum daily flows would be limited during the spawning season (October through November) in order to maximize spawning below the 70 kcfs level on Vernita Bar below Priest Rapids Dam. An instantaneous minimum flow of up to 70 kcfs is to be maintained at Priest Rapids Dam in April for protection of the emerging fry.

There is concern that Intertie decisions could cause a change in the flow pattern in the Hanford Reach, thereby affecting the ability to manage river operations to protect incubating and emerging fall chinook salmon.

Analytical Methods

The analysis of impacts on adult spawning and successful emergence of fry in the Hanford Reach was based on an inspection of flow data from the SAM. For the SAM studies, an average minimum flow rate of 60 kcfs was modeled during the April 1-15 period and the Water Budget minimum flow of 115 kcfs was assumed to be in effect during the April 16-30 period. The goal of the analysis was to determine the extent to which Intertie decisions might alter flows in the Hanford Reach in a way that could create difficulty in balancing spawning and emergence flows.

The flow analysis of Hanford Reach spawning and fry emergence simulated October, November, and April flows at Priest Rapids Dam, located upstream from this section of the Columbia. Spring flows (April 1-15 period average) were compared to flows during the previous fall (October and November) to indicate when there would be a potential impact on emerging juvenile fall chinook.

The test for potential impacts from Intertie decisions is based on the assumption that an October through November daily average flow of 95 kcfs would require an instantaneous flow limit of no less than 70 kcfs in April to avoid significant impacts on emerging salmonids. In addition, regardless of the fall flowrate level, an April instantaneous flowrate of less than 60 kcfs was assumed to have potential impacts.

In order to include spawning flows above the 95 kcfs fall level in the test, the 70 kcfs instantaneous limit was divided by the 95 kcfs fall flow to derive a test criterion for the April instantaneous flowrate of 74 percent of the average October through November flowrate. An

Table 4.2.3-10

FISH STOCKS DEPENDENT ON FISH PASSAGE
IMPROVEMENTS FOR AVOIDANCE OF SIGNIFICANT EFFECTS

Passage Improvements Needed at:	Dam: The Dalles 1/	John Day 2/	McNary	Ice Harbor 2/	Lower Monumental	Little Goose	Lower Granite	Mid-Columbia Projects
To prevent significant impacts caused by:								
Formula Allocation								
Long-Term Firm Contracts								
DC Terminal	John Day SpC Umatilla SS		Tucannon R. SpC Lyons Ferry FC Yakima SpC.		Tucannon R. SpC Lyons Ferry FC			all Mid-Col stocks above R. Is. Dam
3rd AC Intertie	John Day SpC Umatilla SS		Tucannon R. SpC, SS Lyons Ferry FC, SS Yakima SpC		Tucannon R. SpC Lyons Ferry FC			all Mid-Col stocks above R. Is. Dam
Maximum Intertie	John Day SpC Umatilla SS Deschutes SpC Warm Springs SpC		Tucannon R. SpC, SS Lyons Ferry FC, SS Yakima SpC all SS origin McN. Pool		Tucannon R. SpC, SS Lyons Ferry FC, SS	14 stocks 3/ above Lower Granite Dam	14 stocks 3/ above Lower Granite Dam	all Mid-Col stocks above R. Is. Dam

SpC = spring chinook; SuC = summer chinook; FC = fall chinook; SS = summer steelhead

1/ Bypass at The Dalles or other alternative passage actions having similar survival improvements, such as fish transportation from John Day Dam.
2/ Bypass improvements at John Day and Ice Harbor Dams are not needed to prevent significant effects under any BPA proposal.
3/ All 14 critical stocks of spring and summer chinook and steelhead spawning in the Snake River Basin above Lower Granite Dam.

additional 15 kcfs, to account for operational flow fluctuations, was added to the instantaneous flow limits to obtain the monthly average simulated flow limits. Therefore, a positive test is recorded for any simulated water year passing the following Priest Rapids flow criteria: (a) the April 1-15 period average flowrate is less than 15 kcfs plus 74 percent of the October through November average flowrate; and (b) the April 1-15 period average flowrate is less than 75 kcfs (15 kcfs plus 60 kcfs).

A positive test result does not equate directly to adverse impact on salmon spawning or emergence, but it does indicate that in the absence of a FERC Agreement, avoiding impacts would require limiting fall flows or increasing spring flows. The analysis considered the total number of positive test results for all 20 contract years simulated in SAM.

Results

The percentage of positive tests was similar for all cases studied. There was no significant change between the No Action alternative and the formula allocation, firm contracts and expanded capacity options. Without imposing constraints on the hydro system to achieve either reduced fall flows or augmented spring flows, positive test results are triggered in 31.0 percent of the simulations for the No Action case, and in 29.6 to 31.2 percent of the simulations for the test case alternatives (see Table 4.2.3-1). Therefore, no significant impacts on Hanford Reach spawning and emergence flows are expected for any of the Intertie decisions studied.

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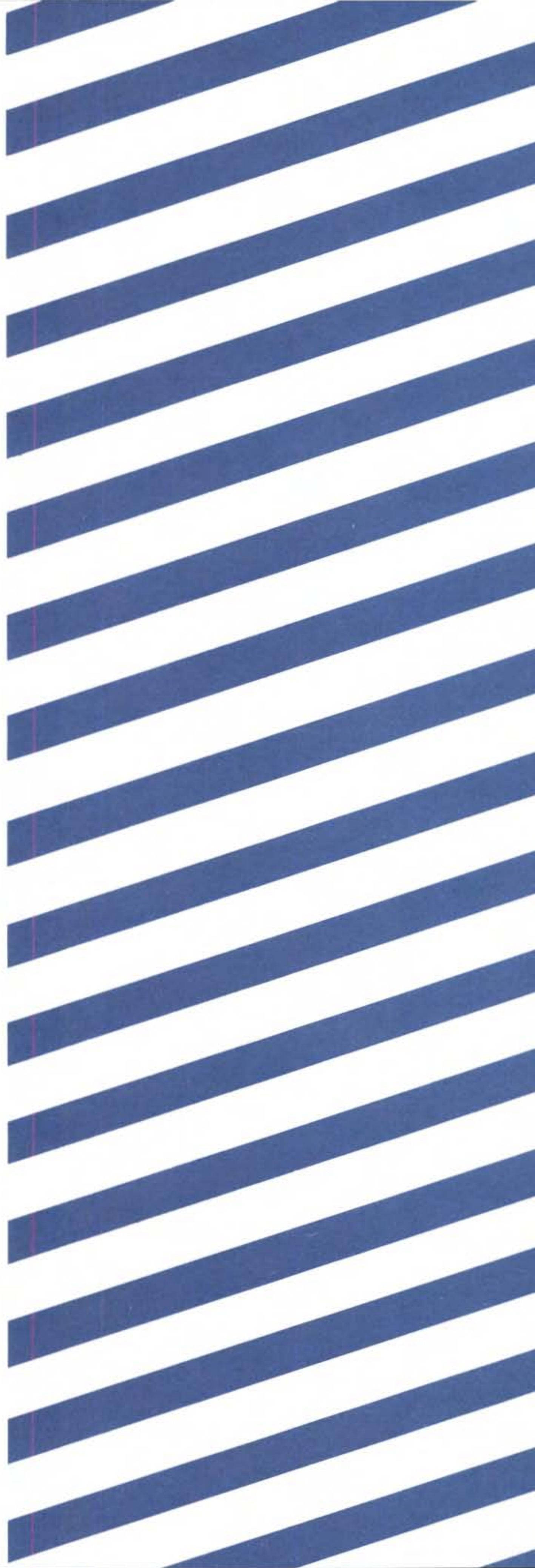

4.2.4 Water Quality and Fish in British Columbia

In British Columbia, BPA's decisions on Intertie access policy or capacity might affect the amount or shaping of power produced at hydroelectric facilities in the Columbia and Peace River Basins. This in turn might lead to different flow rates, reservoir levels, and amounts of spill at hydroelectric projects.

To investigate possible effects in Canada, BPA first used its Systems Analysis Model (SAM) to predict levels of generation, flow rates, and reservoir levels at the following major B.C. hydroelectric facilities (see Figures 3.2 and 3.4 for locations):

A. Peace River

1. Bennett Dam (G.M. Shrum Generation Plant and Williston Lake)
2. Peace Canyon Dam (located on the Peace River downstream of the Bennett Dam)

B. Columbia River Basin

1. Mica Dam (McNaughton Lake)
2. Keenleyside Dam (Arrow Lakes)
3. Duncan Dam (Duncan Lake)
4. Corra Linn Dam (Kootenay River at the outlet of Kootenay Lake)
5. Libby Dam (on the Kootenay River in the U.S.; however, Lake Koocanusa, Libby's reservoir, backs into Canada).

BPA generated the flow and elevation data for both river systems by modeling power production under each scenario, using 200 games of SAM representing a ranges of water conditions, plant outage levels, and variations in load around the mean. A statistical distribution of possible monthly flows and elevations at each of the generating facilities for each of the scenarios was developed. The changes in flows and elevations for each scenario were then used to estimate the potential environmental effects of Intertie decisions.

British Columbia Environmental Concerns

Potential issues were identified through an initial review of the available literature. Issues fell in several major categories: water quality, fisheries, wildlife, and other uses of the river system, including recreation. In this section, issues related to fish and water quality are discussed.

The changes in river operations that lie behind the impacts discussed here are based on BPA's SAM modeling of the BC Hydro system. They would only occur to the extent that the BC Hydro system is operated and continues to be operated as modeled in SAM. BC Hydro may choose to operate its system differently, in order to pursue its own marketing objectives and strategies. Without detailed knowledge of BC Hydro's operational procedures (which was not available), it is impossible to predict with any certainty those impacts on fisheries or water quality due to changes in river operations.

Water Quality

Changes in the operation of large reservoirs that affect downstream flows may affect water quality positively or negatively. Three aspects of water quality are most likely to be affected, with consequent effects on aquatic habitats, recreation, and water consumption. The aspects considered are:

(1) dissolved gas concentrations;
(2) water temperature; and
(3) waste dilution.

Dissolved Gas Concentrations. Dissolved gas concentrations exceeding 140 percent of saturation have been recorded below the Keenleyside Dam (Clark 1977). Concentrations this high have been demonstrated to affect many fish populations adversely (Ebel and Raymond 1976). The high dissolved gas concentrations at Keenleyside Dam are attributed to the entrainment of air by water released from the spillway. Reducing the magnitude and duration of releases at the spillway may benefit downstream fish populations (R. L. & L. Environmental Services Ltd. 1982). Intertie scenarios that increase the use of storage in the Arrow Lakes Reservoir and thus decrease maximum flow releases would probably decrease dissolved gas concentrations downstream of Keenleyside Dam. The Intertie cases that appear to lead to such changes involve either greater Intertie transmission line capacities or Assured Delivery Contracts.

Dissolved gas concentrations have not been noted as a concern at the other Canadian facilities included in this assessment. With the exception of Duncan Dam, all other facilities include power generation capability; at those hydroelectric facilities, most water is not normally released through the spillway. Thus, the likelihood of plunging flows and dissolved gas problems are minimal at these facilities.

Water Temperature. Significant changes in water temperatures are not anticipated from implementing any of the scenarios considered in this assessment. The large volumes and surface areas of the major reservoirs to a large extent control downstream thermal patterns.

Pollutant Concentrations. Reduction in flow releases at Keenleyside could increase concentrations of pollutants in the Columbia River downstream of the pulp mill discharge at Castlegar and the smelter at Trail (MOE 1979). Median low flows for all scenarios are significantly greater than the normal minimum flows currently experienced; therefore, waste dilution should be similar to those presently experienced. Minimum low flow releases at Keenleyside Dam are approximately the same as the 5,000 cfs value claimed by MOE (1979) to be the current minimum. It can be concluded that the concentration of pollutants in the Columbia River would not be significantly affected by changes in policy or Intertie capacity.

Channel Stability

The channel structure of the Columbia River and the downstream portions of the Kootenay River in Canada are largely controlled by existing constraints. The free lowing section of the Columbia River from Keenleyside Dam to the international border lies between high banks (Holland 1976) and is unable to change its course significantly.

The Peace River is still adjusting to its new regulated flow regime (Church and Rood 1982). This adjustment is due to the creation and operation of the Williston Reservoir. It is unlikely, in light of the ongoing adjustments, that the minor changes in operations resulting from Intertie policy or capacity changes would be noticeable.

Some concern has been expressed that regulation of the Columbia River downstream of the Revelstoke Dam has changed the river channel, impairing the water transport of log bundles to the Arrow Lakes Reservoir. Some increase in sediment deposition downstream of Revelstoke Dam has been recorded, and BCHPA (1980) has taken steps to remove the accumulation. The possible effect of Intertie policy or capacity changes on this concern cannot be assessed with the available information.

Water Supply

The City of Castlegar obtains some of its water supply from the Arrow Lakes Reservoir. Since this intake is designed to operate at the minimum reservoir operating level, and the minimum elevations modeled in all scenarios are never lower than the minimum operating level, there should be no problem with the water supply.

Impact on Peace River Ice

Changes in the pattern of flows from Peace River dams may affect the formation and breakup of ice on the Peace River. In the past, ice jams on the Peace River have occasionally led to local flooding during winter, and to local damage to shore property due to the lifting and grounding of ice slabs that are up to 15 feet thick. The primary concern of investigators of the Peace River ice problems has been to identify "existing and potential hazards to life and property that are the results of ice conditions on the lower Peace River" (BCHPA 1975). BCHPA has been attempting to "determine the practical limits of operation" of Peace River power generation facilities "that will not amplify the effects of ice jamming on river stages" downstream.

Examination of the cumulative distribution curves for each scenario shows that power flows from the Peace Canyon facility will, on average, continue dropping throughout the ice break-up period even if there are some increases in flow relative to the base case. Flow increases due to unregulated runoff downstream of the power facilities will continue to be the dominant mechanism in the break-up of the ice sheet in all reaches. The increases in flows during March or April relative to the base case will cause erosion of the ice sheet at the ice front in the upper reach of the river. However, these increases are relatively small when compared to the flow changes initiated by the BCHPA during the 1982 field tests, the effects would be substantially less, no adverse impacts would be expected.

British Columbia Fish

In British Columbia, impacts of Intertie decisions on anadromous fish are not a major issue. It has been almost half a century since the construction of Grand Coulee dam cut off the Canadian reaches of the Columbia River from the migrations of anadromous fish. The Peace River, which eventually empties into the Arctic Sea, is also not a habitat for anadromous fish. On the other hand, both river basins have important resident fish stocks, which potentially could be affected by changes in reservoir levels or downstream flows.

Implications of Intertie Policy or Capacity Changes on Fisheries Resources. Increased fluctuations in water level within reservoirs and changes in flow regulation below reservoirs can have implications for fish and fish habitat. The following section summarizes potential impacts on the aquatic environment resulting from changes in Intertie policy or capacity.

Peace River System

Williston Lake: Potential fisheries concerns resulting from a change in river operations include:

- reductions in spawning habitat through isolation from tributary spawning grounds or exposure of shoreline;
- exposure of littoral zone (highly productive shallow areas of the reservoir) resulting in reduction of plankton and aquatic invertebrates;
- reduction of rearing habitat;
- gas supersaturation due to increased spillage; and
- siltation of spawning habitat.

An increase in Intertie capacity has the greatest impacts on aquatic resources. These changes may reduce summer rearing and spawning habitat for kokanee, lake whitefish, mountain whitefish, peamouth and redshiners. The potential impact of these kinds of alterations in the seasonal schedule of elevations is expected to be small because fish rearing and littoral-zone spawning habitat is already limited by the seasonal changes in reservoir elevation. Relatively small changes in these factors will have relatively small impacts on the fish populations (see Table 4.2.16).

Formula allocation options have the greatest potential for impact. They tend to cause decreases in spring/summer median reservoir elevations, increases in spring median flows and decreases in fall median flows in all test years. This would reduce spring-spawning habitat in reservoirs, increase spring-spawning habitat downstream of the dams, decrease fall-spawning habitat and decrease water cover over incubating eggs laid during the fall. These impacts are not likely to pose a major concern to resident fish populations for two reasons: (1) the decreases in elevation of Williston Reservoir are minor compared to the seasonal change in elevation of 30 ft that presently exists; and (2) the changes in flow from the W.C. Bennett Dam result in a

narrower range of flows over a season and, therefore, a more stable habitat.
Peace Canyon Reservoir and Peace River: Predicted changes are so slight that impacts of any magnitude on fisheries are not anticipated.

Columbia River System

Potential effects on fisheries, resulting from changes in the operations in the Canadian reaches of the Columbia River, arise from fluctuations in reservoir water levels and changes in downstream flows (see Table 4.2.17). The areas of concern include Koocanusa, Duncan, Kootenay, Mica, Revelstoke, and Arrow Reservoirs, and the Kootenay and Duncan Rivers. The variable that result in the most impact for fish is Intertie capacity. The Maximum capacity option tends to have the largest effects of the four Intertie capacity options.

In the Koocanusa Reservoir (Libby Dam) extreme fluctuations in water level presently occur between summer and winter. This has resulted in low productivity within the reservoir, therefore additional potential impacts due to the proposed Intertie policy or capacity changes are expected to be insignificant.

Changes in flow from Libby Dam in the Kootenay River due to the various cases are relatively small and are not likely to have significant impact on the resident fish populations of Kootenay River.

Intertie capacity has the greatest effect on the water surface elevations of McNaughton Lake and on flows from the Mica Dam. Maximum capacity appears to have the largest effect of the four Intertie capacity options. Changed flows from Mica Dam are the most common effect, rather than changed elevations of McNaughton Lake. The impact of changing flows is lessened because Mica discharges directly into Revelstoke Reservoir potential impacts are therefore judged to be insignificant.

Changes in water levels in the Duncan Reservoir are not expected to affect spawning habitat for spring and fall spawners because the water levels already change by 70 ft. in a season. changes in flow may have impact on the rearing and spawning habitat of the Gerrard rainbow trout and kokaneed stocks, but the impact is considered to be small in relation to the impacts of the present seasonal changes in flow.

Arrow Lakes reservoir is located in mountainous terrain and has considerable drawndown. Post impoundment flooding reduced tributary spawning habitat by approximately 30 percent and eliminated the productive littoral area of the lake (Ministry of Environment, 1984). Since impoundment, stocks of kokanee, rainbow trout, and Dolly Varden char have declined substantially. As for the Duncan Dam, all of the cases that include the maximum capacity option aggravate this situation, making the mitigation measures proposed for the Columbia Treaty Projects even more necessary for Arrow Lakes in order to maintain existing stocks.

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Table 4.2.16

CHANGES TO FLOW AND WATER SURFACE ELEVATIONS OF DAMS AND STORAGE RESERVOIRS OF THE PEACE RIVER

		Williston Reservoir William Bennett Dam	Peace River Canyon
A. Effects Intertie Capacity Changes 1/			
DC Upgrade	1)	No significant differences in mediam elevations. Minimum elevations 1-3 ft. lower in 1988.	
	2)	No significant change in flows.	No significant changes in flows.
Third AC/COTP	1)	No significant differences in maximum elevations. Minimum median elevations reached sooner than base case and reach maximum levels 1 month later. Minimum levels 1-3 ft. lower in 1988, 2-7 ft. lower in 1998.	
	2)	10-13% increase in May and 9-28% decrease in Oct.-Nov. median flows.	10-15% increase in May and 0-27% decrease in Oct.-Dec. median flows.
Maximum	1)	Median elevation 1-2 ft. lower in Apr.-Jun. The rate at which annual minimum is reached is faster and the annual peak slower (4-6 ft. lower in Oct.). Minimum elevation is consistantly lower in all years by 2-9 ft.. Maximum difference in 1998.	
	2)	9-34% decrease in Oct.-Dec. median flows and 26-31% incease in May median flows.	9-34% decrease in Oct.-Dec. median flows and 26-31% incease in May median flows.
B. Impacts of Formula Allocation Options 2/			
Proposed Policy	1)	No significant differences in median or maximum elevations. Minimum elevations 1-3 ft. lower in 1988, 2-3 ft lower in 1998 and Jan.-March 2003.	
	2)	No significant differences in median flows.	No significant differences in flows.

Table 4.2.16 (Continued)

		Williston Reservoir William Bennett Dam	Peace River Canyon
Hydro-First	1)	No significant difference in median and maximum elevations. Minimum reservoir elevations are 2-3 ft. lower in winter months.	
	2)	No significant differences in median flows.	No significant differences in flows.
C. Effects of Long-Term Firm Contracts Options 3/			
Federal Marketing	1)	No significant changes in median or maximum reservoir elevations. Small amplitude (1-2 ft.) differences in minimum elevation with no obvious trend with time. 2-5 ft. lower elevations Jan.-Apr. 2003.	
	2)	No significant changes in median flows.	No significant changes in median flows.
Assured Delivery	1)	No significant changes in median or maximum reservoir elevations. Small amplitude (1-2 ft.) differences in minimum elevation with no obvious trend with time. Elevations 1-6 ft. lower throughout 2003.	
	2)	12-19% increase in median May flows and 4-18% decreased in median Nov. flows in all years.	13-19% increase in May flows and 0-18% decrease in Nov.-Dec. median flows in all years.

1/ The impacts described reflect the change from a base case, consisting of Proposed Formula Allocation Option, Existing Capacity, and Assured Delivery of alternative Intertie capacities.

2/ The impacts described refelct the change from the Pre-IAP Formula Allocation Option at Existing capacity and Existing Contracts of alternative Formula Allocations Options.

3/ The impacts described reflect the change from a base case, consisting of the Proposed Formula Allocation Option, Maximum Capacity and Existing Contracts, for altenative long-tem firm contract conditions.

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Table 4.2.17

IMPACTS ON FLOWS AND WATER SURFACE ELEVATIONS OF DAMS AND STORAGE RESERVOIRS IN THE COLUMBIA RIVER SYSTEM IN CANADA

A. Effects of Intertie Capacity Changes 1/

Option	Libby	Mica	Arrow	Duncan	Cora Linn
DC Upgrade	No change.	No significant differences in median, minimum, or maximum elevations and flows.	No significant differences in median, minimum, or maximum elevations and flows.	1) No significant changes in median, minimum, or maximum elevations. 2) Median flows decreased in May 1993.	No change.
Third AC/COTP	No change.	No significant differences in median, minimum, or maximum elevations and flows.	No significant differences in median, minimum, or maximum elevations and flows.	1) No significant changes in median, minimum, or maximum elevations. 2) Median flows decreased in May 1993.	No change.
Maximum	No change.	No significant differences in median, minimum, or maximum elevations and flows.	No significant differences in median, minimum, or maximum elevations and flows.	1) No significant changes in median, minimum, or maximum elevations. 2) Median flows decreased by 10% in May 1993 and 2003.	No change.

B. Impacts of Formula Allocation Options 2/

Option.	Libby	Mica	Arrow	Duncan	Cora Linn
Proposed Policy	No significant differences in median, minimum, or maximum elevations and flows.	No significant differences in median, minimum, or maximum elevations. No change in median flows.	No significant changes in median, minimum, and maximum elevations and flows.	No significant differences in median, minimum, and maximum elevations and flows.	No Change
Hydro First	1) No change in elevations. 2) 11% median flow increase in Oct. 1988; 10% median flow decrease in Nov. 88.	No Change.	1) Median elevations lower in Nov. and Dec. 1988 by 0.3 to 0.7 ft. while minimum and maximum elevations decrease 4.9 and 11.3 ft. and 0.9 to 2.7 ft., respectively. 2) No significant differences in median, minimum and maximum flow.	1) Decrease in minimum, median, and maximum elevations in Nov. to Jan. 1988 by 9.3 to 16.3 ft., 1.2 to 3.6 ft., and 0.1 to 0.5 ft, respectively. 2) Median and minimum flows increased Oct 1988 then decreased Nov-Feb 1988.	1) No change in elevations. 2) 20% increase in median flow in Oct 1988.

Table 4.2.17 (Continued)

C. Effects of Long-Term Firm Contract Options 3/

Option	Libby	Mica	Arrow	Duncan	Cora Linn
Federal Marketing	1) No change in elevations. 2) Decreased median flows Oct, Nov 1988, 1993; increased median flows May, June 1988.	No Change.	1) Median elevation decreases more slowly in Oct-Feb 1988, remaining 4 ft. above base case median. Decrease of 3.8 ft. in April 88 maximum elevations and increase of 3.8 ft. in Dec 1993 minimum elevations. No other significant differences. 2) Median flows decreased in Nov, Dec 1988 and increased Feb to early April 1988. Minimum flow increased by 87% in Jan 1988.	1) Minimum elevations decrease faster in Oct-Feb 1988. Also lower minimum elevations Aug-Sept 1988 (4.4-6 ft) and Sept 1993 (5.8 ft). 2) Median flows increased by 10% Oct. 1988. Minimum flows decreased by 35% and 42% in Nov. 1988 and Dec. 2003, respectively.	1) No change in elevations. 2) 10% decrease and increase in Median flows in Nov 1988 and Sept 1993, respectively. 2) Median flows increased by 10% Oct. 1988. Minimum flows decreased by 35% and 42% in Nov. 1988 and Dec. 2003, respectively.
Assured Delivery	1) Median elevations increased Nov 1988. Maximum elevations increased Jan-Apr 1988. 2) 10% median flow decrease in Oct 1988; 8-10% median flow increase in Sept, Oct 1993, 1998, 2003	1) Increases of 3 to 5 ft in 1988 Jan-Apr and June (5 ft). Median elevations 3 to 5 ft decrease in 1998 Nov and Dec minimum elevations. 2) Median flows decreased by 16% in Jan 1988, increased by 16% in July 1988.	1) Median elevation decreases more slowly in Oct-Feb 1988, remaining 2)4 ft above the base case median. Decrease of 3.8 ft in Apr 1988 maximum elevations and increase of 3.8 ft in Dec 1993 minimum elevations. No other significant differences. 2) Median flows decreased in Nov-Dec 1988 and increased Feb early Apr 1988. Minimum flow increased by 87% in Jan 1988.	1) Minimum elevations decrease faster in Oct-Feb 1988. Also lower minimum elevations Aug-Sept 1988 (4.4-6 ft) and Sept 1993 (5.8 ft) also decreased elevations in Sept and Nov 1998. 2) Median flows decreased in Nov 1988 and 1993 and Mar 1993; increased in Oct and June 1988 and Dec 2003; increased in Jan 1993. Maximum flow decreased in Nov 1988.	1) No change in elevations. 2) 11% decrease in median flow in Nov 1988.

1/ The impacts described reflect the change from a base case, consisting of Proposed Formula Allocation Option, Existing Capacity, and Assured Delivery of alternative Intertie capacities.

2/ The impacts described reflect the change from the Pre-IAP Formula Allocation Option at Existing Intertie capacity and Existing Contracts of alternative Formula Allocation Options.

3/ The impacts described reflect the change from a base case, consisting of the Proposed Formula Allocation Option, Maximum capacity and Existing Contracts, for alternative long-term firm contract conditions.

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4.2.5 VEGETATION AND WILDLIFE

This section addresses the relationship between changes in hydroelectric operations resulting from Intertie decisions and potential effects on vegetation and wildlife.

Reservoir water fluctuation can affect wildlife, both directly and indirectly, through the timing, duration, and amount of release. Proposed Intertie-related changes to system operations may result in increases in fluctuations relative to existing system operations. However, all reservoir operations will always remain within the operational constraints set by the operating agencies and the physical characteristics of the dams.

The greatest effect on wildlife of reservoir water level fluctuations, in the Columbia River and Peace River systems, is through effects on wildlife habitat. This can occur in three ways. First, any effects on prey or browse species of plants or animals will have a corresponding effect on wildlife species. For example, water level fluctuations can affect shoreline vegetation, which may in turn affect deer and elk dependent on riparian browse, smaller mammals and birds dependent on aquatic insects or other riparian invertebrates, waterfowl dependent on aquatic vegetation or invertebrates for food, and mammals and birds dependent on fish for food. This effect is especially important if vegetation is damaged at a critical time of the year, such as when deer and elk need it for winter food or waterfowl need it for shelter or nesting.

Second, erosion of islands would decrease habitat used for bird nesting and deer fawning, and also decrease the amount of shoreline used by reptiles for laying eggs. This is most significant on small islands where such areas might be in short supply.

Third, during low water periods, land bridges may be formed to river islands allowing predators easy access to habitat that would otherwise be isolated. This is of concern a few months out of the year when nesting and fawning is taking place, or when migratory birds use the islands as resting places. However, effects can be long-term if substantial predation occurs during the breeding seasons.

Changes in hydro operations could affect vegetation along shorelines, on islands, and in the drawdown zone, but these changes are expected to be insignificant and within reservoir operations constraints. Therefore, the impacts of Intertie decisions on hydroelectric operations are not expected to result in significant effects on wildlife or vegetation.

Hydroelectric operations may also have direct adverse effects on wildlife. For example, beaver and muskrat can drown when rapidly rising water inundates their dens; or bird nesting and deer fawning islands may be flooded when young are present; or dormant reptiles (summer or winter) may be affected near the low-water levels. Bank sloughing caused by erosion could destroy nests of such species as swallow and kingfisher;

rapidly dropping water levels could strand and dessicate amphibian egg masses. However, the fluctuation changes due to Intertie decisions are not likely to differ significantly from current fluctuations in either their direct or indirect effects on wildlife.

Hydro peaking operations may have very little effect on some wildlife species. The majority of wildlife species in British Columbia are terrestrial, and reservoirs provide habitat for only a narrow range of species. This habitat is affected by the extensive seasonal fluctuations of water levels in the drawdown zone. This zone is devoid of plant cover due to flooding and scouring by waves, ice, and floating debris. Vegetation used by wildlife does not become established in the drawdown zones of the major British Columbia storage reservoirs. Similarly, drying out of the drawdown zones, together with wave action (and ice action during some seasons), severely limits the production of benthic invertebrates (Geen, 1974). As a result, wildlife foods are almost nonexistent in the drawdown zone. Also, the tendency for B.C. reservoirs to be large, deep, cold, windy, and steep-sided creates zones that are not attractive for use by waterfowl.

Changes in hydro operations could affect vegetation along shorelines on islands and in the drawdown zone, but these changes are expected to be insignificant, and within reservoir operations constraints. Therefore, the impacts of Intertie decisions on hydroelectric operations is not expected to result in significant effects on wildlife or vegetation.

In accordance with the Endangered Species Act (16 U.S.C. 1531 et. seq.), BPA proposals and alternatives examined in this document must avoid jeopardizing the existence of any endangered or threatened species. On October 2, 1986, Bonneville Power Administration (BPA) requested from the U.S. Fish and Wildlife Service (USFWS), a list of threatened and endangered species that may be present within the proposed Intertie Development and Use project area. The USFWS responded on November 19, 1986, to BPA's request and included a list of threatened and endangered species.

Based on this list of threatened and endangered species, BPA prepared a biological assessment which determined that the proposed actions are not likely to adversely affect any of the species listed as threatened and/or endangered by the USFWS in the project area. This assessment has been submitted to the Fish and Wildlife Service. Their concurrence with its conclusions will be necessary before the Administrator issues a decision on BPA firm contracts. Further discussion of identified species is included in the attached biological assessment and USFWS list of threatened and endangered species (see Appendix J).

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4.3 THERMAL OPERATIONS

Overview and Summary

The first part of Chapter 4, Environmental Impacts, examined how Intertie decisions could affect the environment through changes in export sales and regional generation levels. The next part of Chapter 4 deals with the effects of Intertie decisions as they relate to the operation of hydroelectric facilities since changes in hydroelectric system operation can affect the environment.

This part of the chapter concerns Intertie decisions as they relate to thermal plant operations in the Northwest, California, and the Inland Southwest. The construction and operation of thermal power generating facilities can affect the environment through changes in consumption of non-renewable resources, emission of air pollutants from operating thermal plants, changes in water use or damage to fish resources connected with plant construction or operation and alterations in wildlife habitat and vegetation. The thermal resources examined are coal, oil, and natural gas and nuclear plants.

Section 4.3.1 examines how changes in the development and operation of the thermal power system that might result from Intertie decisions could affect the consumption of nonrenewable resources. It also addresses the potential land disturbances that are associated with the extraction of nonrenewable resources.

Section 4.3.2 analyzes the potential effects of Intertie decisions on air quality due to changes in plant operations and construction.
Section 4.3.3 discusses how changes in the operation and construction of power plants as a result of Intertie decisions may affect water use and supply and fish resources. Section 4.3.4 covers thermal plant impacts on vegetation and wildlife.

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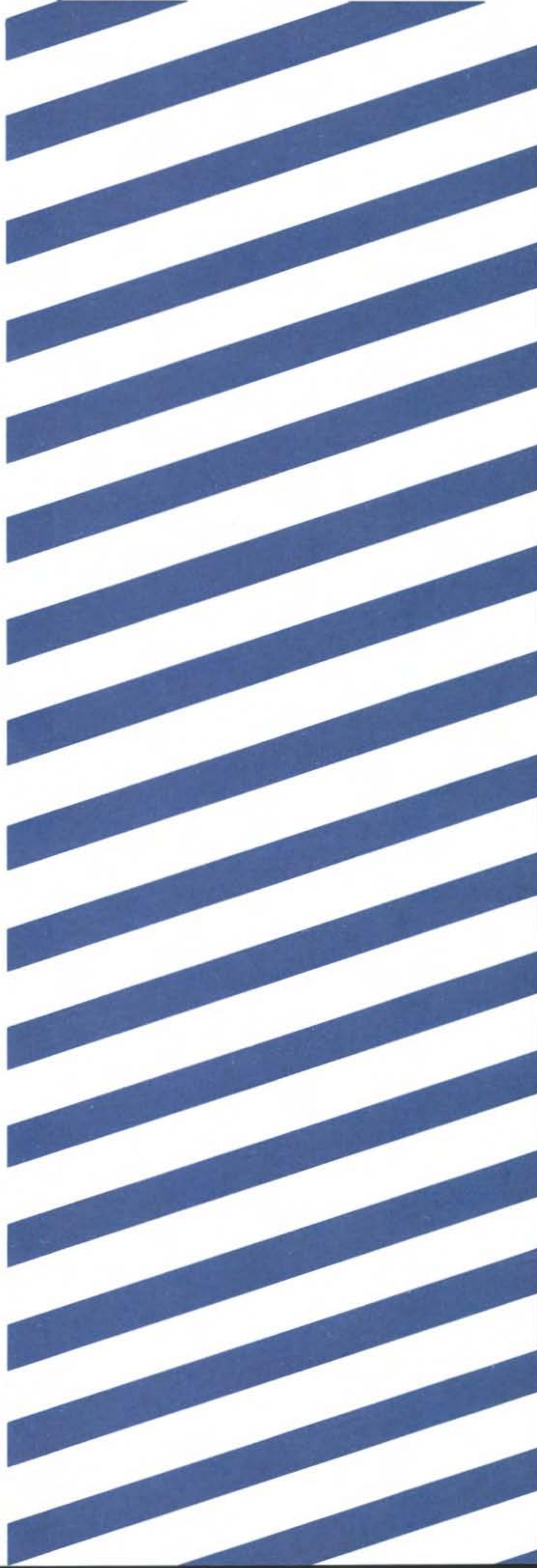

4.3.1 LAND USE AND NONRENEWABLE RESOURCE CONSUMPTION

OVERVIEW AND SUMMARY

Intertie decisions may affect both the operation of existing power plants and the construction of new ones. This section addresses how changes in the development and operation of the power system may affect the consumption of nonrenewable resources such as coal, gas, and oil, as well as the land disturbance associated with the extraction of these nonrenewable resources. Sections 4.3.1.1 through 4.3.1.3 discuss BPA's findings concerning these effects for the Pacific Northwest, California, and the Inland Southwest, respectively. Section 4.3.1.4 discusses the sensitivity of these results to the assumptions used in the analysis for nonfirm rates, California gas prices, California Loads, and Pacific Northwest Loads.

In the PNW and the ISW, Intertie capacity has the largest effect on the consumption of coal. As the capacity increases, coal generation, consumption, and the associated land disturbance increase in the PNW and decrease in the ISW. Alternative formula allocation options have almost no impact on the relative amounts of coal consumed. Both Federal Marketing and Assured Delivery firm sales conditions generally reduce coal use at PNW coal plants, except for 1988 with the existing Intertie. In the ISW, less consistent changes in coal consumption occur as firm sales conditions change. In California, increased Intertie capacity results in decreased consumption of gas and oil. However, the use of these two fuels is not significantly affected by either changes in formula allocation options or firms sales conditions.

Since British Columbia relies strictly on hydroelectric generation for both domestic and export sales, this region is not expected to alter its consumption of nonrenewable resources in response to Intertie decisions. Land use in British Columbia is not expected to be altered significantly although this could change if the proposed Site C dam is built.

The analysis of effects of Intertie decisions on land use and nonrenewable resource consumption in the PNW, California, and the ISW was confined to those plants whose operations were changed by at least 10 aMW relative to the case that assumes the Existing Intertie capacity, the Pre-IAP Formula Allocation option, and Existing Contracts in any of the test cases used for comparison purposes.

Results presented in this section are derived from the results discussed in Section 4.1 pertaining to the impacts of Intertie decisions on generation and export sales. Therefore, if a particular case did not cause coal or combustion turbine (CT) generation to change in the PNW, California, or the ISW, then that case is not discussed in depth in this section.

The EIS studies show that, among the variables considered, Intertie capacity would have the largest effect on the net consumption of oil and gas in 1993 (see Table 4.3.1) as increased sales from the PNW displace the use of oil and gas fired generation. (All Tables in this Section are at the end of the section, beginning page 4.3.1-8, because of their length.) Net decreases in coal consumption also are projected to occur in 1993 at the Maximum Capacity

Intertie size as increases in PNW coal generation are offset by larger decreases in ISW coal generation.

Variations in the formula allocation method and firm contract conditions have small impacts on the use of gas and oil for electricity generation. After 1988, Federal Marketing and Assured Delivery firm sales would generally lead to decreases in coal consumption in the PNW, and thus decreases coal consumption and related land use for surface coal mining. Decreases for Assured Delivery are of greater magnitude.

Finally, in reading Table 4.3.1 and those that follow, it should be noted that a single average MW change in generation requires many tons of coal, whereas it requires many fewer barrels of oil or billion cubic feet of gas. Therefore, large changes in tons of coal consumed are equivalent to small changes in amounts of oil and gas consumed relative to changes in generation. Appendix F contains general data on coal operations in the Pacific Northwest and on oil and gas-fired generation.

4.3.1.1 Effects on Land Use and Nonrenewable Resource Consumption in the Pacific Northwest

Operational effects of different Intertie decisions in the PNW would be limited primarily to hydroelectric and coal plants. Operation of nuclear facilities probably would not be altered, although construction schedules might be affected (See Section 4.1 on generation). Nuclear plants are used as baseload resources (i.e., schedulers attempt to operate them at a constant level of output) since they have low operational costs and since they cannot be brought on-line or off-line quickly. PNW oil and gas generation would probably be unaffected by Intertie decisions, since oil and gas units in the PNW are used only as backup units in case of emergencies or unexpected load increases. The frequency of such extraordinary events would not change with alternative Intertie decisions.

The BPA System Analysis Model (SAM) was used to project generation levels at individual coal plants in the PNW for each Intertie policy/capacity case. Based on information concerning fuel consumption per unit of electricity produced, estimates were developed of the amounts of coal projected to be consumed under each study case. In addition, coal consumption figures for each coal plant were used to develop estimates of the number of acres of land that would be disturbed during the mining operations required to provide this fuel (See Appendix F).

Effects of Increasing Intertie Capacity

Table 4.3.1 presents the projected impact of increases in Intertie capacity for each firm contract case on coal consumption in the PNW. Increased Intertie capacity would lead to increases in coal consumption and related land disturbance in the PNW regardless of the contract scenario assumed. The Maximum Capacity Intertie has the largest impact as more electricity from coal generation is exported on the Intertie to California. For the DC Upgrade, these impacts tend to be about 5 percent of the coal consumed under the Existing Intertie size, or about 400,000 to 800,000 tons of coal annually.

For Maximum Capacity, impacts are about twice as much and range up to 1.8 million tons of coal annually, or about 11 percent of total coal consumption projected for the Existing Intertie size.

Effects of Formula Allocation Options

Tables 4.3.2 and 4.3.3 show the effects of alternative methods of allocating access to the Intertie for economy energy sales, at Existing and Maximum Intertie capacity for each firm contract level. The Proposed Formula Allocation and Hydro-First options, relative to the Pre-IAP option, have only small effects on coal generation and related land disturbance in the PNW at both Intertie sizes examined in this particular analysis.

Effects of Long-Term Firm Contracts

As indicated in Section 4.1, differing levels of firm contracts at either Existing or Maximum Intertie capacities have negligible impacts, generally less than 5 percent, on coal generation. Hence, impacts on coal consumption and associated land disturbance also will be negligible.

Table 4.3.4 shows the effects of different levels of long-term firm contracts on coal consumption in the PNW, assuming the Proposed Formula Allocation. These effects differ somewhat in magnitude, depending on Intertie capacity and study year; however, the size of the differences does not usually change as the level of firm sales condition changes.

Results are similar if the Intertie capacity reaches the DC Upgrade or the Maximum capacity. In these cases, both firm sales conditions result in decreases in coal consumption and associated land disturbance in the PNW after 1988, presumably due to the existence of sales that convert to exchanges once load resource balance is reached, thereby allowing energy from California to displace PNW coal plants. These decreases do not exceed 54 aMW or 287,000 tons of coal annually, which is about 2 percent of the Existing Contracts case.

4.3.1.2 Effects on Land Use and Nonrenewable Resource Consumption in California

California uses substantial quantities of natural gas and oil (in recent years, primarily natural gas) for electricity production. It is uncertain, however, what proportions of oil and natural gas will be used in the future by California utilities. The study results reported here assume that consumption is 90 percent natural gas and 10 percent oil. These resources typically are used to meet only peak load due to their high cost of operation.

Effects of Availability of PNW Surplus Power

Neither hydroelectric nor nuclear plant operations in California are measurably sensitive to variations in the availability of power imports. Oil and gas is the most likely type of generation to be displaced by out-of-state purchases, followed by coal. Other resources (cogeneration, geothermal, and pumped storage) show minor sensitivity to opportunities for displacement.

As reported in the IDU Draft EIS, high availability of PNW surplus would result in reductions in California of gas and oil generation of about 12 percent. Low availability would increase gas and oil generation by about 20 percent.

Effects of Increasing Intertie Capacity

Table 4.3.5 shows the effect of increased Intertie capacity on consumption of gas and oil in California, assuming the Proposed Formula Allocation under each firm contract scenario. For the Existing Contracts case, the DC Terminal Expansion generally would reduce California's consumption of these resources by between 3 and 6.5 percent, relative to the Existing Intertie capacity. The two expansions together would decrease consumption by about 5 percent in 1993, 10 percent in 1998, and 7 percent in 2003. These effects are less than those associated with variations in the availability of PNW power surpluses. The expanded capacity of the Intertie would allow substantially more peak energy from the PNW to be sold to California, resulting in displacement of their oil and gas-fired generating plants.

When the Federal Marketing and Assured Delivery scenarios are considered, impacts of increased capacity are similar to those of the Existing Contracts case.

Effects of Formula Allocation Options

Tables 4.3.6 and 4.3.7 present the effect of alternative formula allocation options for the Existing and Maximum Intertie capacity cases, respectively. Differences in effect of the Proposed Formula Allocation and the Hydro-First options on gas and oil consumption, relative to the Pre-IAP option, are negligible through the study years in all three firm sales conditions at either Existing or Maximum Intertie capacity. The Hydro-First option produces very small increases in gas and oil consumption in all four study years, assuming Existing Intertie size and the Existing Contracts case.

Effects of Long-Term Firm Contracts

Table 4.3.8 shows the effects of alternative firm sales conditions on California oil and gas consumption for each of the three Intertie sizes. Table 4.3.8 shows that Federal Marketing firm sales conditions, assuming the Proposed Formula Allocation option, would generally increase the consumption of gas and oil in California by less than 1 percent, relative to the Existing Contracts case. The Assured Delivery firm sales condition would result in a decrease in oil and gas consumption in 1998 and 2003, after the contracts revert to exchanges. None of these impacts, however, exceeds 2 percent of the Existing Contracts case. Impacts are generally less than 4 billion cubic feet of gas and 7,000 barrels of oil annually.

4.3.1.3 Effects on Land Use and Nonrenewable Resource Consumption in the Inland Southwest

In the Inland Southwest, high availability of low cost surplus power to California from the PNW displaces California's purchases from the ISW and therefore reduces consumption of coal in the ISW by about 5 to 10 percent, due to the price difference. When less surplus power is available, coal consumption may increase in the ISW by as much as 13 percent.

Table 4.3.9 provides information on land disturbance and reclamation efforts associated with significantly affected ISW coal plants.

Effects of Increasing Intertie Capacity

For the Existing Contracts case and assuming the Proposed Formula Allocation, each of the Intertie capacity increases leads to reductions in coal use in the ISW as PNW exports to California increase (see Table 4.3.10), with the minor exception of the DC Upgrade in 1998 when a very small increase occurs relative to the existing capacity. The reductions in coal use for increased capacities of the Intertie range from 48,000 to 243,000 tons annually for the DC Upgrade and 195,000 to 636,000 tons annually for the Maximum Upgrade.

The reduction in ISW land disturbance is about 23 acres in 1993 (about 3 percent of the impact of the Existing Intertie size) for the Maximum Upgrade, and declines thereafter.

Adoption of either the Federal Marketing or Assured Delivery conditions, in place of the Existing Contracts condition, does not alter the impact of capacity increases on ISW coal consumption significantly. In both cases, compared to the Existing Capacity, increased capacity results in decreased coal consumption in the ISW, except for the DC Upgrade in 1998. These decreases range in magnitude from 18,000 tons to 742,000 tons of coal annually, or 0.06 percent to 3.3 percent of the amount for the Existing Intertie capacity.

Therefore, regardless of the level of firm contracts between the PNW and California, increasing the capacity of the Intertie generally results in a small but consistent decrease in coal use in the ISW. This decrease, however, is usually within the range of changes in ISW coal use resulting from the variability from year-to-year of PNW energy for purchase by California.

Effects of Formula Allocation Options

In general, alternative formula energy allocation options at the Existing or Maximum Intertie capacity have little effect on the operation of coal-fired generating stations in the ISW, and hence little effect on ISW coal consumption (see Tables 4.3.11 and 4.3.12). Therefore, few effects on coal consumption in the ISW are expected.

At the Existing Intertie capacity the ISW would not experience any decrease in coal generation or consumption under the Proposed Formula Allocation or Hydro-First options. Increases in consumption would be negligible at higher capacities.

Effects of Long-Term Firm Contracts

Alternative firm sales conditions have little effect (see Table 4.3.13) on coal consumption at existing ISW generating stations through the rest of this century, regardless of Intertie size. At any Intertie size and in any year, the impact of increased firm sales does not exceed 2 percent of the Existing Contracts case. Impacts on annual coal consumption vary from a decrease of 293,000 tons (Existing Intertie, Assured Delivery, 1988) to an increase of 97,000 tons (Maximum Upgrade, Federal Marketing, 1993).

4.3.1.4 Sensitivity and Other Analyses

The sensitivity of the conclusions of this section concerning the impacts of Intertie size, formula allocation and long-term firm marketing decisions to underlying assumptions about the nonfirm rate, the price of gas in California, loads in California, and loads in the PNW also was investigated. All of these sensitivities assume only the Existing Contracts condition. The comparisons dealing with increases in Intertie capacity assume the Proposed Formula Allocation option; comparisons of different formula allocation options assume the Existing Capacity of the Intertie.

New Nonfirm Rate Cap. Using a higher nonfirm rate has little impact on the difference in coal generation in the PNW caused by expanding the Intertie to Maximum Capacity. A higher nonfirm price also has little further effect on the impact of the Proposed Formula Allocation relative to the Pre-IAP Allocation on coal generation in the PNW. This result probably occurs because the price of nonfirm energy has little impact on coal generation, at least within the bounds of the prices being considered, as the price generally obtained for nonfirm generation tends not to justify the operation of a coal plant.

Higher California Gas Prices. Higher gas prices in California have a more profound impact when comparing coal generation with the Maximum Intertie size to that of the Existing Capacity. This result occurs because the higher price of gas in California tends to make coal generation from the PNW more desirable. Furthermore, with expanded Intertie capacity, more of this desirable coal generation is able to reach California markets. However, when comparing the Proposed Formula Allocation option with the Pre-IAP option, high California gas prices have no additional effect on coal generation and consumption in the PNW, assuming the Existing Intertie capacity.

Higher California Loads. Similar results occur if higher California loads are used as are seen for higher gas prices. Higher California loads magnify the impact of the Maximum Intertie size by about 25 to 50 percent. Higher California loads have little effect on the impact of the Proposed Formula Allocation option relative to the Pre-IAP option.

Lower Pacific Northwest Loads. The impact of changing assumptions pertaining to PNW loads is similar to high California gas prices or loads. The impact of increased Intertie capacity is magnified by a lower PNW load, but the impact of the Proposed Formula Allocation option relative to the Pre-IAP option is insensitive to the change in PNW loads.

Assured Delivery Alternatives 1, 2, and 3. Alterntives 1, 2, and 3 contain different amounts of power sales that convert to exchanges, long-term power sales, and seasonal power exchanges relative to the Assured Delivery case. Assuming the Proposed Formula Allocation option and either the Existing or DC Upgrade Intertie capacity, Alternative 1 results in a near-term increase and a larger long-term decrease in coal use relative to the Existing Contracts case. Alternative 2 at the Maximum capacity results in a small, near-term increase and a larger long-term decrease in coal generation and consumption in the PNW. Coal consumption for Alternative 3 with the DC Upgrade or Maximum capacity exhibits a similar variation. The increased levels of power sales in these three alternatives results in completion of WNP-1 and WNP-3 one to two years sooner than for the Assured Delivery alternative.

(VS6-PG-1818Z)

Table 4.3.1

EFFECTS OF INTERTIE CAPACITY ON COAL GENERATION, CONSUMPTION, AND RELATED LAND DISTURBANCE IN THE PACIFIC NORTHWEST 1/

	Intertie Capacity	Coal Generation (aMW)	Coal Consumption (1,000 tons)	Land Use (acres)
Existing Contracts				
1988	Existing	2,105	11,628	487
1993	Existing	2,881	15,989	703
	DC Upgrade	+76	+434	+20
	Maximum	+96	+534	+21
1998	Existing	2,900	16,101	704
	DC Upgrade	+89	+508	+21
	Maximum	+263	+1,480	+67
2003	Existing	3,006	16,673	724
	DC Upgrade	+143	+813	+38
	Maximum	+235	+1,879	+87
Federal Marketing				
1988	Existing	2,154	11,902	504
1993	Existing	2,848	15,813	691
	DC Upgrade	+71	+384	+19
	Maximum	+89	+484	+18
1998	Existing	2,863	15,906	689
	DC Upgrade	+104	+567	+26
	Maximum	+288	+1,607	+76
2003	Existing	3,007	16,683	726
	DC Upgrade	+150	+843	+40
	Maximum	+333	+1,862	+87
Assured Delivery				
1988	Existing	2,204	12,182	522
1993	Existing	2,835	15,744	679
	DC Upgrade	+113	+605	+33
	3rd AC/COTP	+117	+627	+33
	Maximum	+88	+491	+19
1998	Existing	2,828	15,710	678
	DC Upgrade	+135	+747	+37
	3rd AC/COTP	+181	+1,003	+48
	Maximum	+289	+1,606	+77
2003	Existing	2,964	16,443	714
	DC Upgrade	+151	+851	+40
	3rd AC/COTP	+237	+1,338	+64
	Maximum	+338	+1,893	+87

1/ Assumes Proposed Formula Allocation option. Data shown represent coal generation, consumption, and land disturbances for plants showing changes in generation of 10 aMWs or more between the No Action case and any other study configuration. Generation at these plants represents 99 percent of the total coal generation for the PNW. Valmy, Colstrip, Boardman, Centralia, and Bridger show changes of 10 aMWs or more. Valmy represents the total plant.

Source: Generation data from SAM (RESCOAL.ALL, 29 October 1987)
Coefficients from Hinman, 1987.

Table 4.3.2

EFFECTS OF FORMULA ALLOCATION OPTIONS ON COAL GENERATION, CONSUMPTION, AND RELATED LAND DISTURBANCE IN THE PACIFIC NORTHWEST
Assuming Exiting Capacity 1/

	Formula Allocation Option	Coal Generation (aMW)	Coal Consumption (1,000 tons)	Land Use (acres)
Existing Contracts				
1988	Pre-IAP	2,119	11,708	490
	Proposed	-15	-80	-3
	Hydro-First	+30	+152	+10
1993	Pre-IAP	2,841	15,771	+688
	Proposed	+40	+217	+14
	Hydro-First	+8	+39	+4
1998	Pre-IAP	2,879	15,987	697
	Proposed	+20	+114	+7
	Hydro-First	-23	-129	-7
2003	Pre-IAP	3,006	16,685	724
	Proposed	0	-12	0
	Hydro-First	-30	-167	-9
Federal Marketing				
1988	Pre-IAP	2,160	11,936	506
	Proposed	-6	-34	-1
	Hydro-First	+23	+121	+8
1993	Pre-IAP	2,807	15,584	676
	Proposed	+41	+229	+15
	Hydro-First	0	-5	+2
1998	Pre-IAP	2,846	15,812	683
	Proposed	+17	+94	6
	Hydro-First	-13	-74	-3
2003	Pre-IAP	3,005	16,679	725
	Proposed	+2	+4	+1
	Hydro-First	-17	-94	-4
Assured Delivery				
1988	Pre-IAP	2,218	12,260	524
	Proposed	-14	-78	-3
	Hydro-First	-2	-15	+2
1993	Pre-IAP	2,797	15,526	666
	Proposed	+38	+218	+13
	Hydro-First	-4	-28	+0
1998	Pre-IAP	2,806	15,587	671
	Proposed	+22	+123	+8
	Hydro-First	-4	-23	+0
2003	Pre-IAP	2,962	16,439	713
	Proposed	+2	+3	+0
	Hydro-First	-24	-131	-7

1/ Data shown represent coal generation, consumption, and land disturbances for plants showing changes in generation of 10 aMWs or more between the No Action case and any other study configuration. Generation at these plants represents 99 percent of the total coal generation for the PNW. Valmy, Colstrip, Boardman, Centralia, and Bridger show changes of 10 aMWs or more. Valmy represents the total plant.

Source: Generation data from SAM (RESCOAL.ALL, 29 October 1987)
Coefficients from Hinman, 1987.

Table 4.3.3

EFFECTS OF FORMULA ALLOCATION OPTIONS ON COAL GENERATION, CONSUMPTION, AND RELATED LAND DISTURBANCE IN THE PACIFIC NORTHWEST
Assuming Maximum Capacity 1/

	Formula Allocation Option	Coal Generation (aMW)	Coal Consumption (1,000 tons)	Land Use (Acres)
Federal Marketing				
1993	Pre-IAP	2,917	16,179	701
	Proposed	+20	+118	+7
	Hydro-First	-16	-92	-6
1998	Pre-IAP	3,130	17,402	759
	Proposed	+21	+111	+7
	Hydro-First	-2	-14	+0
2003	Pre-IAP	3,321	18,447	806
	Proposed	+18	+100	+6
	Hydro-First	+1	+2	+2
Assured Delivery				
1993	Pre-IAP	2,891	16,051	686
	Proposed	+32	+184	+12
	Hydro-First	-10	-57	-4
1998	Pre-IAP	3,096	17,206	749
	Proposed	+21	+109	+7
	Hydro-First	-10	-12	+0
2003	Pre-IAP	3,283	18,233	794
	Proposed	+19	+103	+7
	Hydro-First	+2	+5	+2

1/ Data shown represent coal generation, consumption, and land disturbances for plants showing changes in generation of 10 aMWs or more between the No Action case and any other study configuration. Generation at these plants represents 99 percent of the total coal generation for the PNW. Valmy, Colstrip, Boardman, Centralia, and Bridger show changes of 10 aMWs or more. Valmy represents the total plant.

Source: Generation data from SAM (RESCOAL.ALL, 29 October 1987)
Coefficients from Hinman, 1987.

Table 4.3.4

EFFECTS OF LONG-TERM FIRM CONTRACTS ON COAL GENERATION, CONSUMPTION, AND RELATED LAND DISTURBANCE IN THE PACIFIC NORTHWEST 1/ 2/

	Contract Case	Coal Generation (aMW)	Coal Consumption (1,000 tons)	Land Use (Acres)
Existing Intertie				
1988	Existing Contracts	2,105	11,628	487
	Federal Marketing	+49	+274	+17
	Assured Delivery	+99	+554	+34
1993	Existing Contracts	2,881	15,989	703
	Federal Marketing	-33	-175	-12
	Assured Delivery	-46	-245	-23
1998	Existing Contracts	2,900	16,101	704
	Federal Marketing	-37	-194	-15
	Assured Delivery	-72	-391	-26
2003	Existing Contracts	3,006	16,673	724
	Federal Marketing	+1	+10	+2
	Assured Delivery	-42	-230	-10
DC Upgrade				
1993	Existing Contracts	2,957	16,423	723
	Federal Marketing	-38	-225	-13
	Assured Delivery	-10	-74	-11
1998	Existing Contracts	2,989	16,608	725
	Federal Marketing	-22	-136	-9
	Assured Delivery	-26	-151	-9
2003	Existing Contracts	3,149	17,486	762
	Federal Marketing	+7	+40	+4
	Assured Delivery	-34	-193	-9
Maximum Upgrade				
1993	Existing Contracts	2,977	16,522	723
	Federal Marketing	-40	-225	-15
	Assured Delivery	-54	-287	-25
1998	Existing Contracts	3,162	17,581	771
	Federal Marketing	-12	-68	-5
	Assured Delivery	-46	-265	-15
2003	Existing Contracts	3,341	18,552	811
	Federal Marketing	-1	-6	+2
	Assured Delivery	-39	-216	-10

1/ Assumes the Proposed Formula Allocation option.

2/ Data shown represent coal generation, consumption, and land disturbances for plants showing changes in generation of 10 aMWs or more between the No Action case and any other study configuration. Generation at these plants represents 99 percent of the total coal generation for the PNW. Valmy, Colstrip, Boardman, Centralia, and Bridger show changes of 10 aMWs or more. Valmy represents the total plant.

Source: Generation data from SAM (RESCOAL.ALL, 29 October 1987) Coefficients from Hinman, 1987.

Table 4.3.5

EFFECTS OF INTERTIE CAPACITY ON OIL AND GAS GENERATION
AND CONSUMPTION IN CALIFORNIA 1/ 2/

	Intertie Capacity	Oil & Natural Gas Generation (aMW)	Oil Consumption (1,000 Bbls) 3/	Gas Consumption (Bcf) 4/
Existing Contracts				
1988	Existing	3,621	495	306
1993	Existing	3,660	499	309
	DC Upgrade	-103	-15	-9
	Maximum	-190	-27	-16
1998	Existing	4,872	666	411
	DC Upgrade	-303	-43	-26
	Maximum	-472	-66	-40
2003	Existing	7,717	1,050	650
	DC Upgrade	-291	-41	-25
	Maximum	-554	-76	-47
Federal Marketing				
1988	Existing Intertie	3,634	496	307
1993	Existing	3,684	502	311
	DC Upgrade	-118	-18	-10
	Maximum	-185	-27	-16
1998	Existing	4,924	672	416
	DC Upgrade	-271	-38	-23
	Maximum	-497	-69	-42
2003	Existing	7,752	1,054	653
	DC Upgrade	-283	-40	-24
	Maximum	-544	-75	-46
Assured Delivery				
1988	Existing Intertie	3,643	497	307
1993	Existing	3,666	500	309
	DC Upgrade	-111	-16	-10
	Third AC/COTP	-121	-16	-10
	Maximum	-187	-27	-16
1998	Existing	4,809	657	406
	DC Upgrade	-284	-40	-24
	Third AC/COTP	-335	-46	-28
	Maximum	-481	-67	-41
2003	Existing	7,669	1,043	646
	DC Upgrade	-302	-43	-26
	Third AC/COTP	-440	-59	-37
	Maximum	-610	-84	-52

1/ Assumes Proposed Formula Allocation option.
2/ Data shown represent oil and gas generation and consumption for plants showing changes in generation of 10 MWs or more between the No Action case and any other study configuration. Genertion at these plants represents 100 percent of the total oil and gas generation for California. This category includes Central Coast, San Francisco, Los Angeles, SE Desert, and San Diego.
3/ Bbls = Barrels.
4/ BCf = Billion Cubic Feet.

Source: Generation data from Marketing LP (RPSE.R9800.DCW.IDUEIS.NOV87. SASOUT, 3 November 1987)
Coefficients from Hinman, 1987.

Table 4.3.6

EFFECTS OF FORMULA ALLOCATION OPTIONS ON OIL AND GAS GENERATION AND CONSUMPTION IN CALIFORNIA
Assuming Existing Capacity

Formula Allocation Option		Oil & Natural Gas Generation (aMW)	Oil Consumption (1,000 Bbls) 1/	Gas Consumption (Bcf) 2/
Existing Contracts				
1988	Pre-IAP	3,645	498	308
	Proposed	-24	-3	-2
	Hydro-First	+54	+7	+4
1993	Pre-IAP	3,665	500	309
	Proposed	-5	-1	0
	Hydro-First	+5	+1	0
1998	Pre-IAP	4,866	665	411
	Proposed	+6	+1	1
	Hydro-First	+11	+1	1
2003	Pre-IAP	7,708	1,049	650
	Proposed	+9	+1	1
	Hydro-First	+33	+4	3
Federal Marketing				
1988	Pre-IAP	3,649	498	308
	Proposed	-15	-2	-1
	Hydro-First	+49	6	+4
1993	Pre-IAP	3,688	503	311
	Proposed	-4	-1	0
	Hydro-First	-5	-1	0
1998	Pre-IAP	4,908	670	414
	Proposed	+13	+2	+1
	Hydro-First	+18	+2	+1
2003	Pre-IAP	7,746	1,054	653
	Proposed	+6	+1	+1
	Hydro-First	+9	+1	+1
Assured Delivery				
1988	Pre-IAP	3,649	498	308
	Proposed	-6	-1	0
	Hydro-First	+30	+4	+2
1993	Pre-IAP	3,668	500	309
	Proposed	-2	0	0
	Hydro-First	+3	0	0
1998	Pre-IAP	4,799	656	405
	Proposed	+10	+1	+1
	Hydro-First	+10	+1	+1
2003	Pre-IAP	7,657	1,042	645
	Proposed	+12	+2	+1
	Hydro-First	+7	+1	+1

1/ Data shown represent oil and gas generation and consumption for plants showing changes in generation of 10 aMWs or more between the No Action case and any other study configuration. Genertion at these plants represents 100 percent of the total oil and gas generation for California. This category includes Central Coast, San Francisco, Los Angeles, SE Desert, and San Diego.

2/ Bbls = Barrels.

3/ Bcf = Billion cubic feet.

Source: Generation data from Marketing LP (RPSE.R9800.DCW.IDUEIS.NOV87. SASOUT, 3 November 1987)

Table 4.3.7

EFFECTS OF FORMULA ALLOCATION OPTIONS ON OIL AND GAS
GENERATION AND CONSUMPTION IN CALIFORNIA
Assuming Maximum Capacity

	Formula Allocation Option	Oil & Natural Gas Generation (aMW)	Oil Consumption (1,000 Bbls) 1/	Gas Consumption (Bcf) 2/
Federal Marketing				
1993	Pre-IAP	3,493	475	294
	Proposed	+6	+1	0
	Hydro-First	+8	+1	+1
1998	Pre-IAP	4,417	602	373
	Proposed	+7	+1	+1
	Hydro-First	+11	+2	+1
2003	Pre-IAP	7,194	978	606
	Proposed	+14	+2	+1
	Hydro-First	+28	+4	+2
Assured Delivery				
1993	Pre-IAP	3,474	472	293
	Proposed	+5	+1	0
	Hydro-First	+7	+1	+1
1998	Pre-IAP	4,323	589	365
	Proposed	+5	+1	0
	Hydro-First	+14	+2	+1
2003	Pre-IAP	7,053	958	594
	Proposed	+6	+1	0
	Hydro-First	-106	-14	-9

1/ Data shown represent oil and gas generation and consumption for plants showing changes in generation of 10 aMWs or more between the No Action case and any other study configuration. Genertion at these plants represents 100 percent of the total oil and gas generation for California. This category includes Central Coast, San Francisco, Los Angeles, SE Desert, and San Diego.

2/ Bbls = Barrels.

3/ Bcf = Billion cubic feet.

Source: Generation data from Marketing LP (RPSE.R9800.DCW.IOUEIS.NOV87. SASOUT, 3 November 1987)

Table 4.3.8

EFFECTS OF LONG-TERM FIRM CONTRACTS ON OIL AND GAS GENERATION AND CONSUMPTION IN CALIFORNIA 1/

	Contract Case	Oil & Gas Generation (aMW)	Oil Consumption (1,000 Bbls) 2/	Gas Consumption (Bcf) 3/
Existing Intertie				
1988	Existing Contracts	3,621	495	306
	Federal Marketing	+13	+1	+1
	Assured Delivery	+21	+3	+2
1993	Existing Contracts	3,660	499	309
	Federal Marketing	+24	+3	+2
	Assured Delivery	+6	+1	+1
1998	Existing Contracts	4,872	666	411
	Federal Marketing	+49	+7	+4
	Assured Delivery	-63	-8	-5
2003	Existing Contracts	7,717	1,050	650
	Federal Marketing	+35	+5	+3
	Assured Delivery	-48	-7	-4
DC Upgrade				
1993	Existing Contracts	3,557	484	300
	Federal Marketing	+9	+1	+1
	Assured Delivery	-2	-1	0
1998	Existing Contracts	4,569	623	385
	Federal Marketing	+81	+11	+7
	Assured Delivery	-44	-6	-4
2003	Existing Contracts	7,426	1,009	625
	Federal Marketing	+43	+6	+4
	Assured Delivery	-59	-8	-5
Maximum Upgrade				
1993	Existing Contracts	3,470	472	292
	Federal Marketing	+29	+4	+2
	Assured Delivery	+9	+1	+1
1998	Existing Contracts	4,400	600	371
	Federal Marketing	+24	+3	+2
	Assured Delivery	-72	-10	-6
2003	Existing Contracts	7,163	973	603
	Federal Marketing	+45	+6	+4
	Assured Delivery	-104	-14	-9

1/ Assumes the Proposed Formula Allocation option.
2/ Data shown represent oil and gas generation and consumption for plants showing changes in generation of 10 aMWs or more between the No Action case and any other study configuration. Genertion at these plants represents 100 percent of the total oil and gas generation for California. This category includes Central Coast, San Francisco, Los Angeles, SE Desert, and San Diego.
3/ Bbls = Barrels.
4/ Bcf = Billion cubic feet.

Source: Generation data from Marketing LP (RPSE.R9800.DCW.IDUEIS.NOV87.SASOUT, 3 November 1987)

Table 4.3.9

COAL SURFACE MINING LAND RECLAMATION ACTIVITIES
RELATED TO ISW POWER PLANTS INDICATING GENERATION CHANGE

Power Plant	Fuel Source (Co., State)	Mine	Tons Mined By Oct 86 1/	Total Land Disturbed 2/ (acres)	Total Land Reclaimed 3/ (acres)
Apache	McKinley, NM	McKinley	40,311,906	3,681	2,842
Coronado	McKinley, NM	McKinley	40,311,906	3,681	2,842
	San Juan, NM	San Juan	41,223,562	2,062	387

1/ Tonnage mined by Oct. 86 is an approximate figure based on available references. None of the figures provided include tonnage mined prior to 1972. Figures for McKinley and San Juan extend through March 1983.

2/ Does not include land used for facilities, road, or power line corridor.

3/ Includes land in all reclamation phases.

Sources: Personal communication with Office of Surface Mining staff, U.S. Dept of the Interior, Denver, Colorado, December 1985-January 1986.

Personal communication with Mining and Minerals Division staff, New Mexico Dept. of Energy and Minerals, January 1986.

Table 4.3.10

EFFECTS OF INTERTIE CAPACITY ON COAL GENERATION, CONSUMPTION, AND RELATED LAND DISTURBANCE IN THE INLAND SOUTHWEST 1/

	Intertie Capacity	Coal Generation (aMW)	Coal Consumption (1,000 tons)	Land Use (acres)
Existing Contracts				
1988	Existing	4,043	19,110	628
1993	Existing	4,755	22,519	758
	DC Upgrade	-50	-243	-10
	Maximum	-133	-636	-23
1998	Existing	5,649	26,618	910
	DC Upgrade	0	+5	+3
	Maximum	-59	-264	-3
2003	Existing	6,246	29,242	1,007
	DC Upgrade	-11	-48	-3
	Maximum	-44	-195	-7
Federal Marketing				
1988	Existing	3,999	18,900	619
1993	Existing	4,767	22,571	758
	DC Upgrade	-51	-245	-9
	Maximum	-123	-590	-22
1998	Existing	5,646	26,604	910
	DC Upgrade	+5	+29	+4
	Maximum	-41	-183	-1
2003	Existing	6,242	29,225	1,005
	DC Upgrade	-8	-35	-2
	Maximum	-45	-198	-6
Assured Delivery				
1988	Existing	3,981	18,813	616
1993	Existing	4,779	22,627	759
	DC Upgrade	-78	-367	-10
	3rd AC/COTP	-124	-586	-20
	Maximum	-156	-742	-25
1998	Existing	5,631	26,534	908
	DC Upgrade	-5	-18	+2
	3rd AC/COTP	-36	-158	-1
	Maximum	-57	-254	-2
2003	Existing	6,234	29,189	1,005
	DC Upgrade	-15	-63	-3
	3rd AC/COTP	-28	-119	-4
	Maximum	-40	-175	-6

1/ Assumes Proposed Formula Allocation option.
2/ Data shown represent coal generation, consumption, and land disturbance changes in generation of 10 aMWs or more between the No Action case and any other study configuration. Generation at these plants represents 40-42% of the total coal generation for the ISW. Plants affected are Cholla, Coronado, Arizona Generic Coal, Springerville, San Juan, Mohave, and Hunter Coal.
3/ Bbls = Barrels.
4/ Bcf = Billion cubic feet.

Source: Generation data from the Marketing LP (RPSE.R9800 DCW.IDUEIS.NOV87.SASOUT, 3 November 1987)

Coefficients from Hinman, 1987.

Table 4.3.11

EFFECTS OF FORMULA ALLOCATION OPTIONS ON COAL GENERATION, CONSUMPTION AND RELATED LAND DISTURBANCE IN THE INLAND SOUTHWEST 1/ 2/
Assuming Existing Capacity

	Formula Allocation Option	Coal Generation (aMW)	Coal Consumption (1,000 tons)	Land Use (acres)
Base Case				
1988	Pre-IAP	4,044	19,115	628
	Proposed	-1	-4	+0
	Hydro-First	+14	+65	+2
1993	Pre-IAP	4,752	22,507	758
	Proposed	+3	+12	+0
	Hydro-First	+6	+30	+1
1998	Pre-IAP	5,643	26,590	909
	Proposed	+6	+28	+1
	Hydro-First	+4	+19	+1
2003	Pre-IAP	6,242	29,225	1,006
	Proposed	+4	+17	+0
	Hydro-First	+6	+25	+1
Federal Marketing				
1988	Pre-IAP	4,007	18,939	621
	Proposed	-8	-39	-2
	Hydro-First	+7	+35	+2
1993	Pre-IAP	4,770	22,585	758
	Proposed	-3	-14	+0
	Hydro-First	+4	+17	+0
1998	Pre-IAP	5,637	26,562	909
	Proposed	+9	+42	+2
	Hydro-First	+12	+57	+2
2003	Pre-IAP	6,242	29,225	1,005
	Proposed	+0	+0	+0
	Hydro-First	-3	-14	+0
Assured Delivery				
1988	Pre-IAP	3,988	18,847	617
	Proposed	-7	-34	-1
	Hydro-First	-1	-5	+0
1993	Pre-IAP	4,776	22,614	759
	Proposed	+3	+13	+0
	Hydro-First	+2	+9	+0
1998	Pre-IAP	5,633	26,542	908
	Proposed	-2	-8	+0
	Hydro-First	+1	+5	+0
2003	Pre-IAP	6,234	29,189	1,005
	Proposed	+0	+0	+0
	Hydro-First	+2	+9	+0

1/ Assumes Existing capacity.
2/ Data shown represent coal generation, consumption, and land disturbance changes in generation of 10 aMWs or more between the No Action case and any other study configuration. Generation at these plants represents 40-42% of the total coal generation for the ISW. Plants affected are Cholla, Coronado, Arizona Generic Coal, Springerville, San Juan, Mohave, and Hunter Coal.
3/ Bbls = Barrels.
4/ Bcf = Billion cubic feet.

Source: Generation data from the Marketing LP (RPSE.R9800 DCW.IDUEIS.NOV87.SASOUT, 3 November 1987)

Coefficients from Hinman, 1987.

Table 4.3.12

EFFECTS OF FORMULA ALLOCATION OPTIONS ON COAL GENERATION, CONSUMPTION, AND RELATED LAND DISTURBANCE IN THE INLAND SOUTHWEST
Assuming Maximum Capacity 1/

	Contract Case	Coal Generation (aMW)	Coal Consumption (1,000 tons)	Land Use (acres)
Federal Marketing				
1993	Pre-IAP	4,651	22,012	737
	Proposed	-7	-32	-1
	Hydro-First	+1	+4	+0
1998	Pre-IAP	5,606	26,427	910
	Proposed	-1	-6	+0
	Hydro-First	-3	-14	+0
2003	Pre-IAP	6,197	29,027	999
	Proposed	+0	+0	+0
	Hydro-First	+2	+8	+0
Assured Delivery				
1993	Pre-IAP	4,627	21,904	735
	Proposed	-4	-19	-1
	Hydro-First	+0	+0	+0
1998	Pre-IAP	5,573	26,275	905
	Proposed	+1	+5	+0
	Hydro-First	+1	+4	+0
2003	Pre-IAP	6,193	29,009	998
	Proposed	+1	+4	+0
	Hydro-First	-3	-13	+0

1/ Data shown represent coal generation, consumption, and land disturbance changes in generation of 10 aMWs or more between the No Action case and any other study configuration. Generation at these plants represents 40-42% of the total coal generation for the ISW. Plants affected are Cholla, Coronado, Arizona Generic Coal, Springerville, San Juan, Mohave, and Hunter Coal.

Source: Generation data from the Marketing LP (RPSE.R9800 DCW.IDUEIS.NOV87.SASOUT, 3 November 1987)

Coefficients from Hinman, 1987.

Table 4.3.13

EFFECTS OF LONG-TERM FIRM CONTRACTS ON COAL GENERATION, CONSUMPTION, AND RELATED LAND DISTURBANCE IN THE INLAND SOUTHWEST 1/ 2/

	Intertie Capacity	Coal Generation (aMW)	Coal Consumption (1,000 tons)	Land Use (acres)
Existing Intertie				
1988	Existing Contracts	4,043	19,110	628
	Federal Marketing	-44	-210	-8
	Assured Delivery	-62	-293	-12
1993	Existing Contracts	4,755	22,519	758
	Federal Marketing	+12	+51	+0
	Assured Delivery	+24	+108	+1
1998	Existing Contracts	5,649	26,618	910
	Federal Marketing	-3	-14	+0
	Assured Delivery	-18	-84	-3
2003	Existing Contracts	6,246	29,242	1,007
	Federal Marketing	-4	-17	-1
	Assured Delivery	-12	-53	-2
DC Upgrade				
1993	Existing Contracts	4,705	22,277	748
	Federal Marketing	+11	+49	+1
	Assured Delivery	-4	-16	+1
1998	Existing Contracts	5,649	26,623	913
	Federal Marketing	+2	+10	+0
	Assured Delivery	-23	-107	-3
2003	Existing Contracts	6,235	29,194	1,D04
	Federal Marketing	-1	-4	+0
	Assured Delivery	-16	-68	-2
Maximum Upgrade				
1993	Existing Contracts	4,622	21,884	735
	Federal Marketing	+23	+97	+1
	Assured Delivery	+1	+2	-1
1998	Existing Contracts	5,590	26,354	908
	Federal Marketing	+15	+67	+1
	Assured Delivery	-16	-74	-2
2003	Existing Contracts	6,202	29,047	1,000
	Federal Marketing	-5	-21	-1
	Assured Delivery	-8	-34	-1

1/ Assumes the Proposed Formula Allocation option.
2/ Data shown represent coal generation, consumption, and land disturbance changes in generation of 10 aMWs or more between the No Action case and any other study configuration. Generation at these plants represents 40-42% of the total coal generation for the ISW. Plants affected are Cholla, Coronado, Arizona Generic Coal, Springerville, San Juan, Mohave, and Hunter Coal.
3/ Bbls = Barrels.
4/ Bcf = Billion cubic feet.

Source: Generation data from the Marketing LP (RPSE.R9800.DCW.IDUEIS.NOV87.SASOUT, 3 November 1987).
Coefficients from Hinman, 1987.

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4.3.2 AIR QUALITY

OVERVIEW AND SUMMARY

Air quality is affected when electric power is produced from such fuels as coal, oil, and gas. When the fuel is extracted, transported, processed, and then burned to operate electric generators, the surrounding air is affected. Power plant construction can also affect air quality on a local scale. The following sections analyze the potential effects of Intertie decisions on air quality due to changes in plant operations and construction.

Intertie sales can allow PNW surplus power to displace more expensive power generated by coal and oil and gas units in California and the Inland Southwest. Increasing the level of Intertie sales decreases the overall impacts of air pollution in the Western U.S. for two reasons:

1. The hydro resources used to generate much of the export power in the PNW and Canada are less damaging to air quality than the oil and gas generation that is displaced in California, and oil and gas and coal plants that may be displaced in the ISW.

2. While PNW coal-fired generating plants produce more air pollutants per unit of energy produced than oil- and gas-fired plants generally used in California, and generally contribute more to ambient levels of air pollution, they are also generally located in sparsely populated areas. California oil and gas resources are frequently in densely populated, urban areas. Therefore, a change in air pollution in the PNW affects far fewer people than an equivalent change in California.

All ambient air quality changes due to changes in formula allocation options, Intertie capacity, and long-term firm contracts are projected to be small, less than Class II Prevention of Significant Deterioration (PSD) increments for Total Suspended Particulate (TSP) and SO_2 (see Section 4.3.2.3).

Increasing Intertie capacity would lead to only small increases in air pollution from coal plants in the PNW, and would allow generation from California plants to be reduced, thus improving ambient air quality by small amounts in heavily populated areas near plants in California. ISW air quality would also be improved slightly because of lower demand for power from plants there.

The DC Upgrade would primarily displace power generation from oil and gas plants located in densely populated areas in the Los Angeles air basin. Large numbers of people should benefit from reduced air pollution.

The Third AC would primarily reduce air pollution in the northern and central areas of California, compared to conditions under Existing Intertie capacity. Although some PNW energy which would be transmitted over the Third AC would indirectly serve southern California, overall there would be less oil and gas generation displaced at plants located in densely populated areas. With both projects built (Maximum Capacity), the benefits of increased Intertie sales would be spread more evenly within California.

The Hydro-First Formula Allocation option seems in general to have some minor benefits to PNW air quality relative to the Proposed Formula Allocation and the Pre-IAP case for 1993 through 2003. For California and the ISW, the choice of formula allocation policy seems to have very little effect on projected air quality.

The firm contracts condition has little effect on PNW air quality. For years after 1988, California and ISW air quality is projected to be better under Assured Delivery than under Federal Marketing or Existing Contracts. This assumes a firm energy sale to California under Assured Delivery, in addition to exchanges, which maintains a net flow of energy from the PNW to California.

4.3.2.1 Plant Operations

Coal. Coal plant operations affect air quality primarily through emissions of pollutants produced when coal is burned. There are also impacts as a result of coal mining. Appendix F provides data on the pollutants associated with coal-fired generation and on the effects of coal mining on air quality.

Coal is often transported to the generating plant by unit train. The train locomotive emits pollutants characteristic of a diesel engine, such as particulates, nitrogen oxides, and carbon monoxide, and the coal cars emit coal dust during the journey. For the PNW, the only plants receiving coal by unit train for which substantial operational effects are shown by the analysis are Boardman and Valmy. In the Southwest, the coal-fired stations in eastern Arizona receive coal by train from mines 100 to 200 miles away in New Mexico.

Dust emissions per kwh of electricity generated by the transported coal during the process of moving the coal from mines to power plants can exceed particulate emissions per kwh from the generating plant itself. However, the sparse population along most of the track, the low effective height of the dust source, and the dust particle size distribution all reduce the polluting potential of these emissions. Coal train pollutants other than dust are emitted in amounts that are small compared to generating plant emissions. Appendix F contains a comparison of coal train and power station emissions.

Dust raised in storing and retrieving coal, lime, or limestone is well controlled by standard practices. No significant emissions are associated with these processes.

Coal-fired power plants primarily emit oxides of sulfur and nitrogen (SO_x and NO_x) and fine particulate matter. Solid wastes (bottom ash, fly ash, and scrubber sludge) also are generated. Sulfur dioxide (SO_2)

can aggravate respiratory ailments such as bronchitis, asthma, and emphysema. It can also mix with other airborne pollutants to soil or corrode rubber, plastics, paints, building stone, metals, and other materials. The Environmental Protection Agency (EPA) and state environmental agencies regulate SO_x emissions from coal-fired power plants. Because of the low sulfur content of Western coal, few problems with removal of sulfur dioxide from stack gases have been experienced, compared with coal-fired power plants in the Midwest and East.

Nitrogen oxides (NO_x), produced during high-temperature combustion, mix with other pollutants to create photochemical smog, which reduces visibility, aggravates respiratory problems, and--under prolonged exposure--leads to general eye, throat, and sinus irritation. 1/

Particulates are solid particles or droplets of liquid (e.g., dust, soot, smoke, and nitrate or sulfate salts) that can cause respiratory ailments and contribute to reduced visibility. Particulates from coal-fired power plants contain trace elements and small amounts of radioactivity.

Several technological advances have contributed to greater control of these airborne pollutants. Advanced coal-washing techniques help remove sulfur from coal before burning. Flue gas desulfurization systems (scrubbers) and electrostatic precipitators can remove sulfur oxides and particulates from stack gases. Changes in the combustion process have successfully limited nitrogen oxide emissions at newer plants. Tall stacks disperse and dilute gases and particulates so that concentrations are lessened before pollutants reach ground level. Although such stacks are effective in lowering the ground-level concentrations of pollutants, they do not reduce the amount of gases and particulates released into the atmosphere by coal-fired plants. In the 1970s, the EPA instituted emission standards for new or substantially modified coal-fired electric power plants. In addition, EPA has required effective monitoring systems to maintain these standards.

Plant operational changes and resulting impacts on air quality must be evaluated on a plant-by-plant basis. Predicting the level of residual concentrations at various distances from the plant site requires detailed knowledge of the meteorology of the area affected because distribution of concentrations of pollutants is governed largely by atmospheric stability and wind patterns. Topography is also an important factor. Most coal plants in the Western U.S. are located in areas with relatively low population density; at these sites, public health impacts will be small or negligible simply because few people live there. Appendix A contains data on coal plant locations and nearby populations in the Pacific Northwest and Inland Southwest.

Acid Deposition. Acid deposition, another air pollution-related problem, is gaining increased attention. Coal-fired generation accounts for about

1/ Nitrogen oxides are not discussed at length here for two reasons. First, existing concentrations of NO_x do not exceed the air quality standards in any of the areas of concern. Secondly, NO_x, as a precursor to the formation of ozone, is accounted for under ozone discussions.

40 percent and 11 percent, respectively, of the total sulfur and nitrogen oxide emissions in the United States (Dvorak et al., 1978). When sulfur and nitrogen oxides are released into the atmosphere, they can combine with moisture or other constituents, oxidizing to form sulfuric, nitrous, or nitric acid or various sulfates and nitrates. Transported over long distances, the acids fall dry or wet (i.e., in rain or snow) to earth. This acid deposition can seriously damage aquatic and terrestrial ecosystems and can reduce agricultural yields.

The extent to which emissions of sulfur and nitrogen oxides contribute to acid deposition depends upon: (1) the amount of oxides emitted; (2) the nature of the chemical transformations that occur after emission; (3) meteorological transportation and dilution; and (4) meteorological factors causing deposition or removal. The significance of the effects of acid deposition depends on the characteristics of the sites upon which acidic materials are deposited, such as the depth and acidity of the soil and species of plants and animals present.

The effects of a particular power plant consequently depend strongly upon its location, the regional climate, and the time of year. The presence of other significant sources of air pollutants is also important to the overall effect. Snow and rain storms lead to more rapid deposition than dry conditions. Deposition is therefore faster in the rainy PNW than in the dry Southwest. Oxidation is slower in clean rural air than in dirty urban air; acid may thus be deposited farther from rural sources than from urban sources. Pollutants released from low stacks can undergo greater dry deposition than those from high stacks. Sources with tall stacks will contribute more to widespread acid deposition than those with low stacks.

The complex transport, transformation, and removal processes involved in acid deposition have been modeled at Argonne National Laboratory using a regional transport approach (Shannon, personal communication, 1986). The results of a tabulation of the amounts of wet and dry sulfur deposited on California and the Pacific Northwest, determined by using this modeling effort, are shown in Table 4.3.14.

Table 4.3.14 compares: (1) the differences in SO_x and NO_x emissions due to increasing Intertie capacity from Existing to Maximum and moving from the Existing to the Assured Delivery contract condition while maintaining the Pre-IAP Formula Allocation option to (2) total annual emissions of SO_x and NO_x for selected states in the study area. The total emissions data were developed by state air quality agencies during recent emissions inventories.

The upper half of Table 4.3.14 compares the base level of emissions for the states involved, determined from recent inventories, to the changes in emissions of sulfur and nitrogen oxides calculated to take place as a result of the shift in Intertie operation. The emission changes are quite small (less than 4 percent in all cases) compared to the base emissions. The bottom half of the table shows amounts of sulfur deposited on the states identified in the left hand column. The second column shows the deposition corresponding to the base level emissions of sulfur from current man-made sources (as opposed to natural sources such as volcanos). For example, the base level of sulfur deposition in California is 159,000 tons in 1985. This deposition arises from the base level emissions mostly in California, but also includes contributions from other states. The matrix of numbers on the right side of the table shows the contributions to deposition on states identified on the left side as a result of changes in emissions from states identified in the column headings. These changes in emissions arise from the proposed changes in Intertie operation described above. For example, under the proposed scenario, sulfur deposition on California from California sources is reduced by 200 tons, but deposition on California from Oregon sources is increased by 1 ton and from Washington sources by 18 tons. The net change in deposition on California is a reduction of about 180 tons. The table shows that the effects of the case assuming Maximum Capacity, the Pre-IAP, and the Assured Delivery contract condition on sulfur deposition in California and the Pacific Northwest are small compared to base levels.

Solid Waste. Removal of the particulates and sulfur oxides from the flue gases of coal-fired power plants produces large amounts of fly ash and scrubber sludge. These, together with bottom ash, constitute the principal solid wastes to be disposed of at the plant sites. The disposition of these materials at the coal-fired stations in the PNW and ISW which are substantially affected by Intertie decisions is shown in Table 4.3.15.

Many of the plants do not have scrubbers and therefore do not have to dispose of scrubber sludge. Most of those that do have scrubbers store the sludge permanently in clay-lined ponds near the plants. The bottom and fly ash also may be stored in ponds, but more often are used as landfill or in some cases as a constituent of cement.

Plants that depend on pond disposal must have adequate land available to accommodate the ponds developed over the life of the plant. The area required over the life of the plant for a 500 MW plant with associated ash and scrubber sludge storage is several hundred acres (U.S. Department of Energy, Energy Technology Characterizations Handbook, 1983).

Oil And Natural Gas. The most polluting stage in the natural gas supply system is early production when the gas wells are being drilled and prepared for production. During this stage, considerable amounts of sulfur oxides are released. During the subsequent extraction, separation (of the gas from oil and/or water), gathering, and initial processing, some gases may be released through flaring, venting, leaking, and production operations (US DOE, 1983). These gases can include methane and hydrogen sulfide (H_2S), as well as nitrogen oxides (NO_x), sulfur dioxide (SO_2), and combustion products from the gas fuel used in compressor engines and steamboilers. Overall, however, such releases are small compared to the releases in the power plants. Less than 10 percent of the gas used in California comes from wells within California. The rest originates outside the state. Appendix F contains data on approximate air pollutant emissions during initial well development, extraction, and processing compared to those from a gas-fired power plant.

Table 4.3.14

EFFECTS OF MAXIMUM CAPACITY AND ASSURED DELIVERY ON SULFUR OXIDE AND NITROGEN OXIDE EMISSIONS AND SULFUR DEPOSITIONS

Emitting	Total State Emissions (1000 tons)			Change in Annual Plant Emissions 1/ (1000 tons)		Change in Annual Emissions (percent)	
State	Year	SOx	NOx	SOx	NOx	SOx	NOx
California	1983	1095	208	-1.32	-2.33	-0.12	-1.12
Oregon	1985	43	189	0.08	0.02	0.19	0.02
Washington	1985	245	292	6.54	1.05	2.67	0.36
Montana	1985	87	-	0.73	-	0.84	-
Wyoming	1983	129	44	1.71	1.53	1.33	3.48

SULFUR DEPOSITION

State Receiving Deposition	Base Annual Sulfur Deposition	Annual Change in Sulfur Deposition Accompanying Change in Thermal Plant Operation* (1000 tons)						
			State Emitting Sulfur					
		Year	CA	OR	WA	MT	WY	Total
California	159	1983	-0.203	0.001	0.018			-0.184
Oregon	14	1985	-0.004	0.010	0.125			0.131
Washington	30	1985	-0.001	0.006	0.741			0.746
Idaho	15	1980	-0.005	0.002	0.088	0.010	0.005	0.100
Montana	14	1985	-0.004	0.002	0.151	0.113	0.030	0.292

1/ Compares the Existing Capacity, Pre-IAP, Existing Contracts case with the Maximum Capacity, Pre-IAP, Assured Delivery case for study year 2003.

Sources: State emissions from state air quality agencies; deposition values based on calculations by Shannon, Argonne National Laboratory (personal communication).

Table 4.3.15

SOLID WASTE DISPOSAL FROM COAL-FIRED POWER PLANTS

Plant	Scrubber Wastes (Calcium Sulfite-Sulfate Sludge)	Bottom/Fly Ash
PACIFIC NORTHWEST		
Boardman	No Scrubbers In Use	Minor Onsite Disposal; Contractor Removal
Centralia	No Scrubbers In Use	Onsite Landfill
Colstrip	Permanent Disposal Ponds Near Plant	Used for Fill Material Near Plant Site
Jim Bridger	Permanent Disposal Ponds Near Plant	Onsite Landfill; Contractor Removal
Valmy	Permanent Disposal Ponds Near Plant	Onsite Landfill; Contractor Removal
INLAND SOUTHWEST		
Cholla	Permanent Disposal Ponds Near Plant	Onsite Ponds
Mohave	No Scrubbers In Use	Onsite Landfill; Contractor Removal
Coronado	Lined Onsite Pond	Onsite Landfill
San Juan	No Scrubbers In Use	Onsite Landfill
Springerville	Dry Scrubber Offsite Landfill	Offsite Landfill
Hunter	Permanent Disposal Ponds Near Plant	Onsite Landfill

Sources: Personal Communication with Plant Engineers and/or Environmental Managers, April 1987, and EEI Statistical Data Base.

Note: Contractor removal includes use for fill material or cement.

Extraction of oil involves processes similar to those for natural gas, including a separation process. Associated air pollution consists of hydrocarbons and combustion products released when spilled crude oil evaporates or is burned. In some locations (such as offshore), oil produced during testing also is burned. The amounts of air residuals released in this way are small on an overall basis, although there may be considerable local effects.

Transportation of gas or oil produces air residuals through the operation of the compressor pumps for pipelines and of engines used in transport vehicles. The amounts of air emissions in all cases are small (University of Oklahoma, 1975) compared to those from electric generating plants.

Oil refineries are, in general, major sources of air residuals. Fuel burning process heaters and refinery boilers, for example, produce large amounts of sulfur oxides, nitrogen oxides, and hydrocarbons, and moderate amounts of particulates and carbon monoxide. Appendix F provides data on the air pollutant releases for an average refinery with controlled emissions, compared to those from an oil-fired power plant.

Although refinery releases are not insignificant, oil refinery operation in California does not necessarily change in proportion to California utility use of oil; moreover, it is difficult to tie changes in generation at western gas- and oil-fired plants to particular refineries. While BPA's Intertie decisions may possibly affect the level of pollution from refineries, the difficulty of linking those decisions to specific levels of pollution at specific refineries precludes quantitative analysis of potential impacts on refinery emissions in this EIS.

Combustion products from oil-fired generation--primarily sulfur oxides, nitrogen oxides, carbon monoxide, particulates, and hydrocarbons--represent the most significant air residues. These pollutants are controlled with stack gas scrubbers, baghouses (devices which use fabric to filter particulate pollutants from the air), electrostatic precipitators, combustion control techniques, and are dispersed through tall stacks.

Gas-fired power plants emit almost no sulfur oxides; they also have very small particulate emissions. A natural gas-fired plant typically produces less than 5 percent by weight of the sulfur and particulate emissions of a coal-fired power plant, and substantially less than an oil-fired plant. The major emissions of gas-fired generation are nitrogen oxides, which occur in lower quantities than they do in oil or coal burning. Gas-fired power plants in California often use combustion control techniques and special boiler designs to limit the production of nitrogen oxides.

Air quality impacts on human health and materials depend on the numbers and types of nearby receptors. Because most of the California oil and gas plants are located in urban areas with large populations, the magnitude of their air pollution impact on materials and human health may be greater than that of coal plants in rural or remote areas. Appendix A provides population figures for the substantially affected air basins in California.

Conservation. Changes in Intertie policy or capacity may affect the rate of development of conservation resources. The major environmental effect associated with energy conservation to date is on indoor air quality, which stems from weatherization, an important element of conservation programs for several years. Appendix F contains additional information on weatherization and indoor air pollution.

Changes in conservation efforts related to different Intertie decisions may not affect indoor air pollution levels since much of the possible residential weatherization in the PNW has already been done. Where potential problems are known to be significant, conservation development plans in the PNW generally include measures, such as air-to-air heat exchangers, to mitigate indoor air pollution problems. Steps to avoid or minimize effects on indoor air quality are also incorporated into commercial building programs. Because conservation programs include measures to mitigate potential indoor air pollution problems, no attempt has been made to quantify the effects of indoor air quality changes in this EIS.

Nuclear Power. Changes in Intertie capacity or policy could affect the schedule of the development of nuclear power resources in the PNW. The stages in the nuclear fuel cycle that may affect air quality are uranium mining, milling, uranium hexafluoride production, enrichment, fuel fabrication, power production, and waste disposal. Additional data on air quality effects of nuclear power can be found in Appendix F. Since air pollutant emission rates from nuclear plants are small and because changes in nuclear plant operations would not be expected as a result of the proposed actions, this EIS does not consider the impacts of air pollutant emissions from nuclear reactors further.

4.3.2.2 Analytical Methods

Quantitative analyses of Intertie effects on air quality focused on air pollutant quantities and ambient levels, specifically for sulfur dioxide (SO_2), TSP (total suspended particulate), and ozone (O_3). The analytical methods used for the air quality analysis are described in Appendix G.

Scenarios combining capacity, formula allocation, and firm contract conditions were quantitatively analyzed to determine the air quality effects at substantially affected fossil-fuel-fired generating plants located in California, Oregon, Washington, Montana, Wyoming, Nevada, Utah, Arizona, and New Mexico, during the period 1988-2003. A plant was defined as being substantially affected if its projected annual generation changed by 10 average MW or more under any scenario from the no action alternative (i.e., Pre-IAP, Existing Intertie, and Existing Contracts). There will be no impacts on air quality in Canada because the BC Hydro system is based on hydroelectric power.

Changes in ambient levels of SO_2, TSP, and ozone were determined by modeling and comparing existing average regional air quality and pollutant concentrations to the generation levels associated with alternative Intertie scenarios. Several air dispersion models were used.

Calculations of the effects of Intertie policy or capacity changes on air quality were prepared for the area within 75 kilometers of each substantially affected PNW and ISW coal plant, based on the calculations of generation levels described in Section 4.1. In California, many oil and gas plants are located near each other in the same air basin. The calculations for such plants assumed that the emissions from the plants become well mixed in the air basins in which they are located, specifically the San Francisco, Los Angeles, and San Diego basins. Other California plants, (e.g., the Moss Landing and Morro Bay plants) were handled like the PNW and ISW plants, because they are relatively isolated and would have little cumulative impact with other substantially affected plants. For each case (i.e., combination of Intertie size, formula allocation, and contracts level), changes in average annual SO_2, sulfate (SO_4), and TSP ambient concentrations associated with substantially affected power plants resulting from changes in their annual generation were calculated. For the three urban California air basins of San Francisco, Los Angeles, and San Diego where ozone is a concern, changes in average annual ambient ozone concentrations were also calculated. Changes in maximum hourly ambient concentrations of SO_2 and TSP, based on the change in average annual generation, were also calculated. The maximum hourly concentration calculations were made assuming the same numerical difference in generation over an hour as the difference in annual average generation levels. In actuality, the changes in average annual generation for a plant may come about through a combination of displacement, or shutdown, of the plant at times that it might otherwise be operated, as well as reduced generating levels when it is being operated.

It is not known at this time what mix of oil and gas will be used by the oil and gas plants; however, in the analysis, it was assumed that the mix is 90 percent gas and 10 percent oil. The emissions of air pollutants in each case were related to the amounts of fuel burned using emission factors found in reports prepared by the utilities for the California Energy Commission.

4.3.2.3 Results of Quantitative Analysis

Effects of Variation in Availability of PNW Power for Export

As noted in Section 4.1, normal variation in the availability of PNW surplus power for export, due to water and other uncertain conditions, has a major effect on levels of generation in California and the ISW. Generation levels at coal, oil, or gas-fired generating plants directly affect regional air quality. Larger amounts of PNW surplus available for export generally lead to a temporary lessening of air pollution contributions from California and ISW generating plants. Reduced availability of PNW surplus energy for the export market lessens the ability to displace California and ISW generating plants, increasing air pollution contributions from those power plants.

To the extent that the ability to transfer PNW surplus energy to California and the ISW is constrained by limitations of Intertie capacity or policy, potential air quality benefits to these areas will not materialize. The maximum levels of air pollution contributions from California and ISW generation would occur when no PNW energy is available for delivery over the Intertie. This maximum level is set by the characteristics of the California and ISW resources and is independent of Intertie size or formula allocation.

Effects of Increasing Intertie Capacity

The effect of Intertie capacity increases on air quality was determined for each Intertie upgrade assuming the Proposed Formula Allocation at various firm contract levels. Because of the valume of the results of the air quality analysis, they have been included as part of Appendix G rather than reproduced here. Appendix G, Tables G.6, G.7, and G.8 display the results showing effects of increasing Intertie Capacity on air quality from which the following conclusions were drawn.

Pacific Northwest. Increases in Intertie capacity could allow the PNW to sell more export power to California. This may lead to increased generation at PNW coal plants, as described in Section 4.1, resulting in increases in air pollution in the PNW.

All increases in Intertie capacity result in increases in pollutant concentrations; however, all of the concentration changes are negligible, both absolutely, and as percentages of Class II Prevention of Significant Deterioration (PSD) increments. Class II PSD increments are frequently used as criteria for assessing the degree of significance of air quality changes in this EIS. They were established by EPA as a regulatory mechanism to limit the deterioration of existing ambient air quality from construction or development of new air pollution sources. They do not apply to and have no regulatory relevance to changes in air pollution which result from changes in operation of existing air pollution sources within permit limits, as are the changes generally being examined here.

Class II PSD increments (moderate development and air quality deterioration allowed) are shown below:

		Class II
TSP	Annual Geometric Mean	19 $\mu g/m^3$
	Maximum 24-hr. average	37 $\mu g/m^3$
SO_2	Annual Arithmetic Mean	20 $\mu g/m^3$
	Maximum 24-hr. average	91 $\mu g/m^3$
	Maximum 3-hr. average	512 $\mu g/m^3$

Source: 40 CFR Part 51 Revised as of July 1, 1987.

No Federally mandated PSD increments have been established for ozone (O_3) or sulfate.

California. Increases in Intertie capacity generally reduce air pollution in California as more PNW imports displace in-state generation. However, projected changes in ambient concentrations are quite small in the contexts of the projected levels with only the existing Intertie, of the National Ambient Air Quality Standards, and of the Class II PSD increments. The DC Upgrade, which will deliver power directly to the Los Angeles area, will lead to air pollution reductions primarily in the Los Angeles air basin. Because of that area's high population, reduced air pollution will benefit large numbers of people. The Third AC, on the other hand, would directly serve northern and central California and indirectly serve Southern California. Some of the PNW power brought in over the Third AC would displace power produced at plants in the Los Angeles area. Nonetheless, fewer people would benefit from the air pollution reductions with the Third AC than with the DC Terminal Expansion. The Maximum Upgrade leads to a more even distribution of the benefits of reduced air pollution than either the DC Upgrade or the Third AC alone.

Inland Southwest. Increasing the capacity of the Intertie generally reduces predicted operation of ISW fossil fuel plants and hence decreases air pollution in this region. However, the decreases in annual average concentrations for the increased capacity cases are small, both absolutely, and in comparison with ambient standards and Class II PSD increments.

Effects of Formula Allocation Options

The effects of formula allocation options were examined by comparing the three options, assuming Existing Intertie capacity and three firm contract levels, and in addition, assuming Maximum Intertie capacity, with Federal Marketing and Assured Delivery firm contracts for 1993, 1998, and 2003. Appendix G, Tables G.9 through G.14 present the results of the air quality analysis from which conclusions about the air quality effects of Formula Allocations were drawn.

Pacific Northwest. Alternative formula allocation options could slightly change the amount of coal generation in the PNW, as indicated in Section 4.1. All of the concentration changes corresponding to changes in formula allocation in the tables are small in comparison to the absolute value computed for the Pre-IAP cases and are far below the Class II PSD increments.

The Hydro-First option seems in general to have some minor benefits to PNW air quality relative to the Proposed Formula Allocation and the Pre-IAP case for 1993 through 2003. This is because the Hydro-First option satisfies more of the California and ISW market with hydro energy, leaving a smaller residual amount of market to be met by other resource types. Thus, PNW coal resources are run less.

California. The concentration changes for SO_2 and TSP due to changes in the formula allocation option are generally even smaller for the California air basins than for the PNW subregions. Changes in ozone concentrations are also insignificant. There is little difference among the options with respect to projected effects on air quality in California.

Inland Southwest. Impacts on air quality in the ISW due to changes in formula allocation options are very small. There is little difference among the options with respect to projected effects on ISW air quality.

Effects of Long-Term Firm Contracts

The three firm sales conditions are examined for the Existing, DC Terminal Expansion, and Maximum Intertie capacity levels. All comparisons assume the Proposed Formula Allocation. Appendix G, Tables G.15 through G.17 show the results of the air quality analysis from which conclusions regarding the air quality effects of long-term firm contracts are drawn.

Pacific Northwest. The three levels of long-term firm contracts examined have little effect on air quality in the PNW.

California. In general, long-term firm contracts are associated with small changes in air pollution in California. For years after 1988, impacts of Assured Delivery generally are either smaller increases in air pollution than Federal Marketing, or decreases in cases where Federal Marketing produces small increases. This is because the exchange provisions of Federal Marketing require California utilities to generate electricity to return to the PNW at certain times, whereas Assured Delivery, in addition to exchange provisions, includes a firm sale such that the net flow of energy is still to California. The air quality effects in California are generally somewhat smaller than those in the PNW in terms of concentrations of pollutants, although in both regions the changes are very small. However, because of the higher population of the urban California air basins, the impact of air quality changes is greater there than in the PNW.

Inland Southwest. The Assured Delivery contracts case generally seems to benefit ISW air quality more than the Federal Marketing or Existing Contracts cases, but all changes in ambient concentrations are small.

4.3.2.4 Monthly Departures in Ozone Concentration

Ambient ozone concentrations are sensitive to seasonal conditions. NO_x emissions, one of the pollutants generated by California oil and gas fired generating plants is an important factor in the atmospheric chemical reactions which form ozone. Therefore, an additional analysis, besides the determination of annual average ambient ozone concentration reported in the Tables in Appendix G for the urban California air basins, was performed to determine if Intertie decisions are likely to significantly change ambient ozone concentrations on a monthly basis.

Changes in ozone levels in the Los Angeles Basin can be estimated from EKMA based on emission of NO_x and hydrocarbons. Seasonal patterns in ozone levels occur mainly due to changing meteorological conditions and incoming solar radiation, with changes in precursor emissions having a negligible effect. Furthermore, changes in electric generation within the basin have virtually no effect on total hydrocarbon emissions for the region. Therefore changes in ozone levels can be estimated on a monthly or yearly time scale solely from changes in NO_x emissions.

During the period April through October, ozone levels often approach or exceed ambient air quality standards, while the other months are safely below this level (See Figure 4.3.2.1, which shows monthly variations in ozone levels at Fontana, California, near Los Angeles.). For this reason, only changes during the non-winter months are estimated.

Monthly departures from the annual average megawatt changes are used to estimate the monthly ozone departures. Three different sets of ozone isopleths are used corresponding to the three seasons (April-May, Spring; June-August, Summer; September-October, Fall). In this way changes in local meteorology and incoming sunlight are accounted for. It should be noted that there can be a factor of 2 to 3 difference between these estimates depending on the specific conditions. There are even circumstances where decreased NO_x emission can result in ozone increases. For the calculations used in this study, the isopleths that appear to be most consistent have been chosen. Results of the monthly departures from annual average ozone changes are presented in Table 4.3-16 for two comparisons. Changes in some instances are large compared to annual average ozone changes; however, even the largest monthly changes would not be expected to produce noticeable effects on the ozone levels in the Los Angeles Basin.

4.3.2.5 Sensitivity and Other Analyses

The sensitivity analyses which were performed (See 4.1.3) showed some situations where air quality impacts could be different than under the assumptions used for the original analysis.

Higher California Gas Prices. If Intertie capacity is increased and California gas prices are higher than assumed in the original analysis, more PNW coal generation is operated in each of the future years of the analysis to displace larger amounts of California generation. Thus, air quality in the PNW would deteriorate in comparison with the levels projected in the original analysis, and California would receive increased air quality benefits. Since the air quality level changes predicted in the original analysis were so small, however, it is not expected that the effects of a higher California gas price would change the overall conclusion of the original analysis. Air quality impacts would still be expected to be very small even with higher California gas prices.

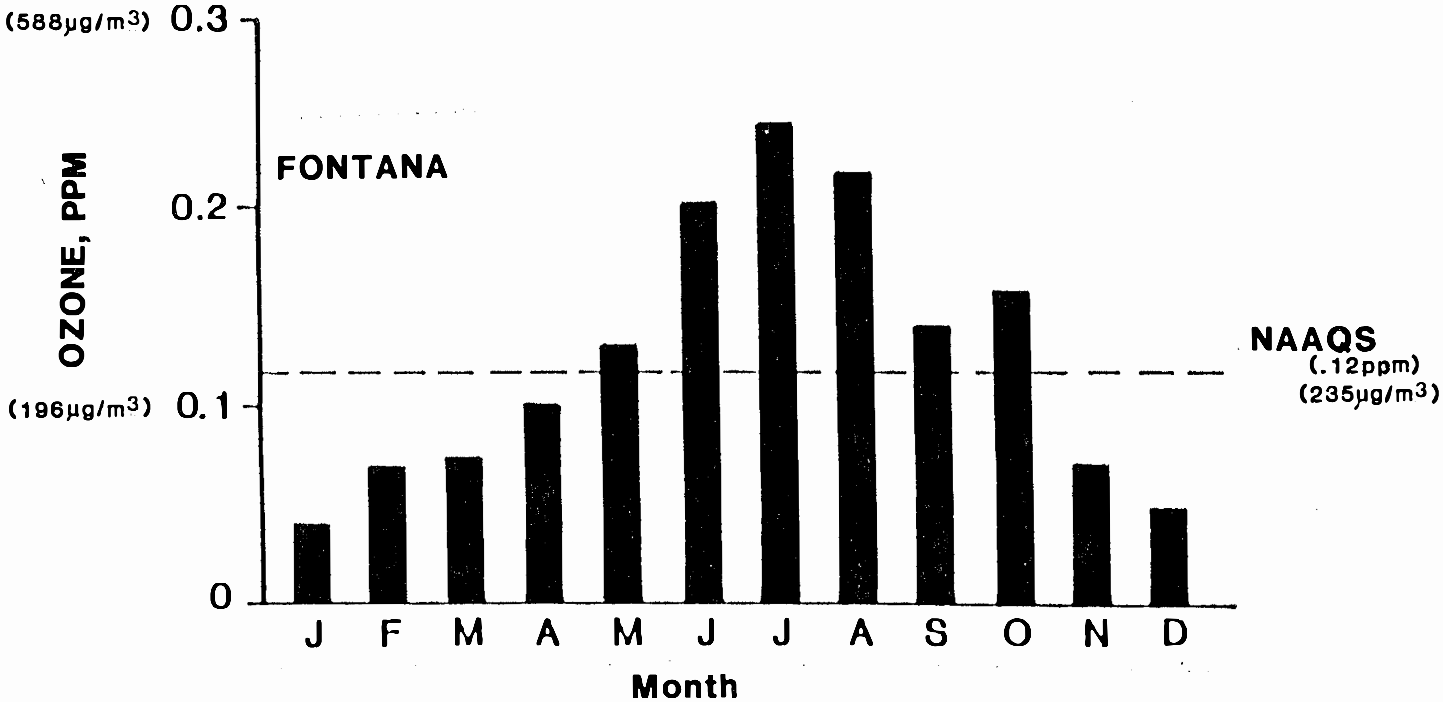

FIGURE 4.3.1

SEASONAL VARIATION OF AVERAGE DAILY MAXIMUM 1-HOUR OZONE CONCENTRATIONS AT FONTANA FROM 1976 THROUGH 1978

Source: SCAQMD (1981b)

Table 4.3-16

MONTHLY DEPARTURE FROM ANNUAL AVERAGE
OZONE CHANGES FOR LOS ANGELES ($\mu g/m^3$)

	1987-88	1992-93	1997-98	2002-03
Comparison No. 1 1/				
September	-0.38	0.06	-0.09	0.00
October	-0.05	-0.26	-0.11	-0.38
April	0.00	0.00	-0.74	-1.09
May	0.00	0.00	-0.72	-2.19
June	-0.20	-0.54	-1.46	-2.70
July	-0.78	-1.58	-2.29	-1.82
August	-0.22	-0.22	-0.24	0.33
Annual	-0.22	-0.32	-0.84	-1.06
Existing Contracts Comparison No. 2 2/				
September	-0.38	-0.09	-1.52	0.00
October	-0.05	-0.26	-0.13	-1.53
April	0.00	0.00	-0.99	-1.30
May	0.00	0.00	-0.77	-2.19
June	-0.20	-0.82	-1.46	-2.70
July	-0.89	-1.63	-2.29	-1.82
August	-0.22	-0.22	-0.24	-0.49
Annual	-0.37	-0.30	-0.96	-1.25

1/ Change from Proposed Formula Allocation, Existing Capacity, and Assured Delivery to Proposed Formula Allocation, Maximum Capacity, and Assured Delivery.

2/ Change from Proposed Formula Allocation, Existing Capacity, and Existing Contracts to Proposed Formula Allocation, Maximum Capacity, and Assured Delivery.

Higher California Loads. With increased Intertie capacity and higher California loads than assumed in the original analysis, a fairly large increase in PNW exports of coal-generated energy is shown by the sensitivity analysis relative to what is shown by the original analysis, but in later years studied in the sensitivity analyses, this effect largely disappears. Thus, there would be a short-term enhancement of air quality in California, and a short-term deterioration of air quality in the PNW. Again, these relative differences in air quality are not expected to be significant because the changes in air quality projected under the original analysis were so small.

Lower Pacific Northwest Loads. Finally, in the situations studied for the sensitivity analysis in which Intertie capacity increases are assumed to coincide with lower PNW loads than under the original analysis, quite large increases in PNW exports of electric energy, relative to that projected in the original analysis, occur. The amount of these exports increases over time. This situation could result in some substantial air quality benefits to California. In this case, the exported energy comes predominantly from hydro resources, so there would be very little deterioration of air quality in the PNW.

Assured Delivery Alternatives 1, 2, and 3. Regardless of the Intertie capacity, Assured Delivery Alternatives 1 through 3 result in small increases in use of Pacific Northwest coal resources early in the period of the analysis. This would lead to slight degradation of Pacific Northwest air quality, although these would not be significant as evidenced by the very small projected ambient air quality changes for the PNW found throughout the analysis. Alternatives 1, 2, and 3 enhance net exports from the Pacific Northwest to California, a consequence of the assumed firm sales and exchanges in them, relative to the Existing Contracts case for a given Intertie size and assuming the proposed Formula Allocations. Therefore, in these situations, Alternatives 1, 2, or 3 would lead to greater air quality benefits in California.

(VS6-PG-1819Z)

4.3.3 WATER USE AND FISH

As discussed elsewhere in Section 4.3, Intertie decisions may affect the operation and construction of power plants. This section addresses how such changes may affect water use and supply, and fish resources. It discusses, by power generation plant type, how the operation of the power system may affect water resources and fish.

Overview and Summary

Changes in the operation or composition of the power system resulting from changes in Intertie capacity, policy, or interregional power contracts, may affect water use, water supply, and fish by several means, including changes in hydroelectric and thermal plant operations. The issues related to water use and fish differ greatly from region to region. In the PNW and British Columbia, changes in the operation and development of the hydroelectric system potentially could affect the fishery resources of the Columbia and Peace River basins. In California and the ISW, the potential effects on water use and consumption due to the operation of existing or new thermal plants are the primary issue.

4.3.3.1 PLANT OPERATIONS

The operation of a thermal generating plant requires that fuel be acquired, prepared, transported, and consumed, and that any wastes be disposed of. Hydroelectric plants, while requiring none of these steps, can still significantly affect aquatic resources. The discussion below focuses on how the operation of different power plant types may affect water resources and fish.

Coal

Surface mining may affect both surface water and groundwater. Water bodies can be contaminated by fuels; herbicides; blasting residues (ammonium nitrate); polychlorinated biphenyls (PCBs); and trace elements leached from piles of soil and other materials removed during surface mining, and later used to reclaim the site ("spoil piles"). If water is used in the mining process, the water table may be lowered, indirectly affecting streams, lakes, and other water resources. Where water is scarce (as in the northern Great Plains, Inland Southwest, and Rocky Mountain regions), livestock, wildlife, and human consumers may be affected. Water use is heaviest for irrigating revegetation projects at mine sites. A typical water requirement for a surface mine is around 360,000 gallons per average megawatt of energy produced by the coal that is mined.

Strip mining removes vegetation and disturbs the ground, leading to increased runoff, erosion, and wind-blown dust. Increased sediment and silt deposition in nearby waters may reduce the kind and number of invertebrate fauna and fish species. Less light penetrates the waters and primary production is reduced. Increased runoff also increases nutrient loading, which at higher levels may reduce fish populations while increasing vegetation (eutrophication).

In the Great Basin and ISW, rainfall is limited and evaporation is high. Runoff can be easily diverted, so virtually no wastes are discharged to surface water (Hittman, 1974). However, runoff from surface disturbances becomes more rapid during storms and may affect the variability of streamflows. Changing flow regimes can change fish habitat, and may shift species abundance (Bovee, 1982; Raleigh et al., 1984; Moyle and Nichols, 1974). Temperature and oxygen content of the water may also change (Garcia et al., 1985).

Most detrimental impacts on water resources can be minimized by suppressing dust, controlling erosion, and treating runoff waters in settling ponds to collect sediment or hazardous material. Many of the impacts discussed above are regulated by Federal, State, and local mining laws. The Surface Mining Control and Reclamation Act of 1977 mandates State permit systems governing environmental standards for maximum recovery of coal; restoration of land to its original contour; use of explosives; waste disposal; construction of access roads; and revegetation. Wastewater discharges from surface mines are also regulated under the Clean Water Act through water quality standards; effluent limitations for new and existing sources; permit programs; and areawide planning (Office of Technology Assessment, 1979). The Clean Water Act requires the best practicable control technology currently available for area runoff from coal mines. All Western surface mines currently operate in compliance with the Surface Mining and Clean Water Acts (M. Shilling, personal communication). Assuming that compliance continues, the Intertie-induced indirect effects related to coal mining upon water use will be negligible.

Coal transportation has minimal impacts on water resources. Dust may enter the water, but only when roads or train tracks are near water. Coal slurry pipelines can use large amounts of water, depleting water for other uses such as fish and wildlife, irrigation, and stock watering. However, in the study region, only the Mohave plant is supplied by a coal slurry pipeline. Changes in generation will not significantly affect water consumption by this pipeline as it operates at constant capacity, regardless of generation.

Coal processing and storage has little or no impact on water use. Since Western soils are largely alkaline in the area of coal storage piles, acidic drainage is not likely to be a problem, as the natural alkalinity in the soil quickly neutralizes any acidic runoff.

At many plants, limestone is used in air pollution control processes. Limestone preparation and storage generate dust and runoff, which can carry calcium, carbonates, bicarbonates, and other dissolved and suspended solids to local waters, increasing their hardness and alkalinity (Dvorak et al., 1978; APHA, 1980). Impacts from limestone processing and storage are site-specific, depending on amount of limestone, rainfall, runoff potential, the size of receiving water body, and environmental controls. Runoff and dust controls are required under the Federal Water Pollution Control Act (1972), as amended (Clean Water Act), and under the Resource Conservation and Recovery Act (Office of Technology Assessment, 1979; Hittman, 1974).

The major impacts on water use and fisheries associated with the coal plant fuel cycle are related to coal combustion: the acidification of natural water bodies via airborne pollutants ("acid rain"); and water consumption, heat discharge, and fish entrainment related to plant cooling.

Acid Deposition

Emissions from coal plants have been identified as a factor in acid precipitation in some parts of the country. However, the contributions of individual sources of emissions are relatively small, and because the emissions and their products are often transported great distances by complex meteorological processes, acid precipitation is a regional problem that has proved impossible to link precisely and quantitatively with particular sources (Dvorak et al., 1978; Schindler et al., 1981). With intense rainfall, decreases in rain pH (i.e., greater acidity) have been observed downwind in close proximity (within 5 km) to coal-fired plants. In Western states, the water bodies that are more sensitive to acidification are those at high elevations in mountainous areas (Potter, 1982; EPA, 1982; Logan et al., 1982).

In general there are no long records of acid deposition rates at any site in the West. However, as shown in Appendix A, some areas have recently experienced rainfall with a pH below that generally considered natural (pH 5.6) for pure rain (Gibson, 1981). It is not possible to link the pH of rain at these stations to discharges at individual, or groups of, power plants. Extensive research on acid deposition nationwide and in California is currently being conducted by EPA, public utilities, universities, and state agencies.

The major impacts of acid deposition on water use and aquatic life can be summarized as follows. Very acidic (low pH) runoff may enter streams and rivers quickly and in large quantities during periods of snowmelt. Different fish species vary greatly in their tolerance of low pH. Among the salmonids present in the high mountain streams, rainbow trout are most sensitive. Some species are more sensitive at certain times of the year; and smaller, younger fish are often more sensitive than larger, older ones. Low pH may alter reproduction rates or may kill eggs, larvae, fingerlings, or adults. Death may be a direct response to low pH or to increased metal concentrations at low pH (e.g., aluminum toxicity). Increased acidity may kill indirectly, through gradual losses due to chronic low-level contamination. Sensitive species may be eliminated from a community, and shifts may occur in predator-prey relationships, competition, or other community-level interactions. Other aquatic biota in the community may be similarly affected.

Aquatic systems with a pH below 5.0 are generally very restricted in fishery resources, but these low pH levels are not now occurring in areas which might be impacted by the Intertie. About 90 percent of high elevation Adirondack (New York) lakes that are acidified and have a pH below 5.0 are not supporting any fish life (Schofield, 1981). In Nova Scotia, nine rivers with a pH of 4.7 no longer support salmon or trout reproduction. In general, most lakes in the Sierra Nevada have a low buffering capacity and pH levels between 6 and 7 (K. Tonnessen, 1981). The acidity of Pardee and Hetch Hetchy reservoirs has been increasing somewhat since at least 1954, but was not lower than 6.8 in the early 1980's (McCall, 1981). At Shaver Lake, also in the Sierras, pH values were between 6.8 and 7.0 in 1986 and in the past 19 years were generally above 6.7 (excluding bottom readings). Readings varied with depth and location within the lake.

At Galena Lake in the Rocky Mountains, acid rain has been recorded (mean pH of 4.2 in the summer of 1980), alkalinity levels were low, and the lake pH was about 6. The sources of the acidity were unknown (Harte, 1981). In summary, although acid precipitation occurs over areas to be affected by potential Intertie related decisions, the acidity cannot be linked to specific power plants. Although high altitude regions in the study area are sensitive, they are not now exhibiting significant, negative impacts from the acid deposition they are receiving.

Trace Elements

Coal combustion also releases particulates that can carry trace elements. These particulates may fall immediately in wet or dry form or may be airborne and fall far from the source. Trace elements react in complex ways in aquatic environments. The effects of these elements on biota can include acute mortality, reduced survival and growth, impaired reproduction, structural damage, modified behavior, and reduced crop production (Potter, 1982). Effects on water bodies can also be insignificant, as water temperature, hardness, pH, and dilution volume may modify toxicity. A modeling study by Dvorak et al. (1977) concluded that, for a power plant in a given drainage basin, a stream with a mean annual flow of 1,000 cubic feet per second provides enough dilution to reduce trace element concentrations to below levels toxic to aquatic biota and current water quality thresholds. Many streams near coal plants influenced by Intertie decisions fall below this flow level during at least part of the year. Most studies of trace element contamination near specific plants have shown few significant effects (Office of Technology Assessment, 1979). However, it is possible that significant effects due to lower levels of contamination over wider areas may exist.

Thermal Plant Cooling Systems

The use of ground or surface water for cooling in a coal-fired plant can adversely affect both water use and quantity. Further, aquatic biota may be drawn into (entrained in) cooling water intakes. The extent of such impacts depends on the water source (natural surface water, groundwater, or power plant reservoir), the type of cooling system (once-through or closed-recycle), and the organisms present in the water bodies from which cooling water is drawn and to which it is discharged. Because the impacts on water quality and fish due to the cooling cycle in oil/gas plants are essentially the same as the cooling cycle impacts of coal plants, both types of impacts are covered here. The paragraphs that follow examine and, in some cases, quantify potential effects of Intertie decisions on water resources due to cooling requirements at thermal plants.

Closed-cycle Cooling Systems. These systems include cooling ponds and towers. They cool the plant by circulating water through the plant and then into a special pond or tower, where evaporation and exposure to air cool the water. Water is recirculated through the plant and cooling tower or pond, and replenished only to the extent that it evaporates. These systems discharge heat to the atmosphere rather than to water. In general, entrainment of fish is not a significant problem for these systems. However, evaporative losses can make water consumption very high (see Table 4.3.17).

Water consumption can be a significant issue when the amount of the withdrawal due to plant cooling is high relative to the amount of water at the source. For streams and rivers, this may be an issue only at certain low-flow periods, when additional flow reductions might be harmful to fish spawning and migration, and to other wildlife or uses. Cooling water consumption from underground sources can be an issue when the amount of the withdrawal is a significant portion of the total recharge of the aquifer. In parts of the ISW, where precipitation is low, it may not take much change in the consumption of groundwater to equal a significant fraction of annual recharge.

Table 4.3.17
WATER REQUIREMENT OF ALTERNATE COOLING SYSTEMS FOR FOSSIL FUEL POWER PLANTS

	Acre-Feet/Average Annual MW			
TYPE	Evaporation	Blowdown and drift	In Plant Use	Net Consumption
Once-through	8.7	0	1.1	9.8
Mechanical Draft Evaporation Tower	13.6	6.9	1.1	21.6
Natural Draft Evaporation Tower	12.8	6.4	1.1	20.3
Cooling Pond	18.7	7.4	1.1	24.4 1/
Spray Pond	13.4	15.5	1.1	30.0
Dry Tower	-	-	1.1	1.1
Wet/Dry Tower	intermediate between dry and wet tower	1.1	4.3 - 21.4	

Adapted from Thomas (1975)

1/ Some contribution due to precipitation on pond.

Because closed-cycle cooling can cause substantial consumption of water through evaporation, consumption of ground and surface water was calculated for Intertie policy and capacity cases. All five of the PNW plants with substantial changes in generation attributable to Intertie decisions use closed-cycle cooling systems. Three plants (Colstrip, Centralia, and Bridger) draw makeup water from rivers, the fourth (Valmy) uses well water, and the fifth (Boardman) uses a cooling lake (Carty Reservoir) replenished by the Columbia River. In California, among substantially affected plants, only the Coolwater plant uses closed-cycle cooling. In the ISW, all of the significantly affected plants use closed-cycle cooling.

Significance of impacts was determined using a stepwise elimination process. First, maximum changes in generation (either negative, positive, or both) under all policy/capacity cases were calculated. Plants with generation changes of less than 10 average annual MW in any case were eliminated from further consideration because this level of change was considered to be within the "noise" of the System Analysis Model and marketing LP outputs (i.e, this level of change was not substantial). For plants with increases or decreases in generation greater than 10 average annual MW, water use under the maximum change condition was calculated. The change was compared with indices of supply and/or pre-existing use. Calculations of water usage assumed a direct proportional relationship between plant generation and water use (Table 4.3.17). However, this is strictly true only if plants are equipped with variable speed pumps. In practice, pumps may be left running during nongenerating periods to enable fast startup on demand. Water use impacts are therefore probably somewhat overstated by this analysis.

Water consumption varies among power plants. Withdrawal requirements vary with evaporation losses, cooling system needs, and water quality. All comparisons of water use by plants and discharge to surface waters were based on discharge conditions in the early 1980s. Actual stream discharges in the future may be different, but no attempt was made to forecast actual stream discharges for future years.

For most plants using water from surface streams, change in water use was compared to the minimum daily stream discharge for the period of record of the source water. This is a very conservative first-cut and represents an extreme worst case scenario.

Measurements of stream discharge reported by the U.S. Geological survey (USGS) are estimates made with varying precision. This precision is generally known and is reported for most USGS gauge stations. Records rated as "excellent" signify that 95 percent of measured daily discharges are within 5 percent of the true value, "good" ratings are within 10 percent, "fair" within 15 percent, and "poor" have less than fair accuracy (John Bader, pers. comm., May 1987). Levels of change within the error range would be unmeasureable. In addition, surface runoff in any area varies from year to year depending largely on meteorological conditions. This variation is usually much greater than the measurement error. Therefore, impacts were considered insignificant if the magnitude of change fell within the error range of discharge measurements (i.e., 5 percent for excellent rating, 10 percent for good, etc.). Results of this analysis are presented in Table 4.3.18.

El Centro power plant uses water diverted, primarily for irrigation purposes, from the Colorado River at Imperial Dam. Water consumption by El Centro power plant represents a small portion of the amount of water diverted (Leamon Murphy, pers. comm., Feb. 1988). Potential changes in consumption related to changes in generation at the plant (which in the case of the largest decrease is 7.5 percent, and in the case of the largest increase, was 1.7 percent) would have inconsequential effect on the Colorado River. Whether any effect would be observed is questionable since water rights govern how much water can be diverted and, even with reduced consumption by El Centro power plant, the same amount of water may still be delivered.

Thus none of the surface waters would be projected to be impacted significantly by even the projected generation changes of largest magnitude at power plants using them as a water source. Since impacts were insignificant at the extreme generation changes, it is concluded that none of the policy/capacity/firm contract level cases have significant impacts at these plants.

For plants using groundwater for cooling, a similar approach has been used. Groundwater resources are less accurately measured than surface water resources. Aquifer recharge is the volume of water which enters a groundwater basin, usually measured on an annual basis. It comes from precipitation in the basin, seepage from surface water, and inflow of groundwater. Often, recharge is only roughly estimated from water budgets, or is not known at all.

Recharge estimates were available only for the Valmy plant. Decreased generation at Valmy results in decline in water use equivalent to 3.1 percent of annual recharge (Table 4.3.19). These changes are insignificant (Tom Gallagher, pers. comm., May 1987).

Characteristics of the groundwater resources impacted by the Coronado, Cholla, and Springerville plants are not well known. For these areas only data on recent pumpage from regional aquifers are available. These figures (Table 4.3.19) predate development of Cholla Unit 5 and all generation at Springerville. Since these plants dominate consumption in the area, use of these figures probably results in overestimates of impact. The maximum impact of Intertie development and use at the Cholla and Coronado plants is not significant. To further evaluate the impact at the Springerville plant, water consumption by the plant was estimated for the policy/capacity comparison which gave the maximum increase in generation. The change in water use, expressed as a percentage of base case consumption, is a decrease of 4.3 percent for the maximum impact scenario (Table 4.3.20). This is not likely to significantly affect groundwater depletion in the area.

Groundwater data are not available for two of the California plants (Coolwater and Etiwanda). The only information available to evaluate impacts is the estimated current water use of the plants. Maximum change in generation at these plants results in estimated declines in water use of 15.0 percent and 11.0 percent (Table 4.3.21). Operation of the Coolwater plant has resulted in overdraft of the aquifer with the result that poorer quality water has been drawn into the area (David Kay, SCE, pers. comm.). Decreased pumping at this plant would help alleviate that situation.

Once-through Cooling Systems. These systems withdraw water, pass it through the condenser where it picks up heat from condensing steam, and return it directly to its source. This method consumes much less water than closed-cycle systems, but it produces large volumes of heated wastewater discharge and can entrain large numbers of organisms. Organisms pulled in with the water can die from thermal shock, mechanical stress, striking intake screens, and biocides (chemicals added to cooling water to prevent algae growth). (Ulanowicz, 1975; Schubel, 1975; Horst, 1975; Marcy, 1975). Entrainment can be a significant problem in estuaries, coastal areas, and large rivers where water is withdrawn for once-through cooling. Water heated during the once-through cooling process and discharged to its source may be lethal to fish, fish eggs and larvae, and other aquatic life in receiving waters (Salia, 1975; Jensen, 1977). The potential environmental damage of once-through cooling has greatly restricted its use in new plants (Thomas, 1975).

None of the significantly affected ISW or PNW coal and none of the ISW oil/gas plants use once-through cooling. In California, however, fifteen thermal plants discharge water directly to coastal waters (see Table 4.3.22). The major impacts from these plants are the discharge of heated wastewater and entrainment of fish and other aquatic life in cooling systems.

Although cooling water discharges often result in thermal plumes with substantially warmer water than ambient water temperatures, a review of environmental studies at the California plants indicate that in general no appreciable detrimental effects on aquatic life have been observed (Tetra Tech, 1976; Stephens, 1977; Pacific Gas & Electric, 1973b, 1973c, 1973d, 1977a, 1977b).

Studies at Pittsburg Power Plant (PG&E, 1973b) found that no direct and consistent relationship existed between plant output and plume size. However, the study notes that a large reduction in plant load is reflected in a marked reduction in area, extent and heat content of the plume. The study did not quantify this effect. The study also noted that the thermal plume was primarily a surface effect, with temperature increases at depth confined to the immediate vicinity of the discharge structure. Similar results were observed at the Morro Bay, Hunters Point, and Moss Landing power plants (PG&E, 1973c, 1973d, 1973e).

Studies at Elkhorn Slough have indicated that although the power plant does entrain organisms and emits a thermal plume, there are no overall, significant impacts. Any effects of power plant operation are overshadowed by other, more extensive modifications such as historic removal of tidelands by dikes and the opening of the Slough to extensive

Table 4.3.18

MAXIMUM IMPACT ON SURFACE WATERS OF THE PACIFIC NORTHWEST AND INLAND SOUTHWEST

STATE	PLANT	WATER BODY	MEAN ANNUAL DISCHARGE (AC-FT)	YEARS OF RECORD	RECENT YEAR DISCHARGE (AC-FT)	MINIMUM DISCHARGE (AC-FT/DAY)	YEAR	MAXIMUM CHANGE IN GENERATION (aMW)	CHANGE IN WATER USE (AC-FT)	PERCENT OF MINIMUM DISCHARGE 1/	RECORD RATING
PACIFIC NORTHWEST											
OR	Boardman	Columbia River	140100000	104 yrs	165700000	24000	1968	24, -2	585.6	0.0	Excellent
WA	Centralia	Skookumchuck River	183300	1930-82	238600	167	1982	100, -33	2160.0	4.0	Good
WY	Bridger	Green River	1277000	33 yrs	1677000	337	1955	124, -59	2678.4	2.0	Good-Poor
MT	Colstrip	Yellowstone River	8620000	1978-84	8780000	12246	1984	105, -25	2268.0	0.0	--
INLAND SOUTHWEST											
NM	San Juan	San Juan River	1705000	1913-83	1847000	28	1939	9, -32	-845.6	-8.0	Good
UT	Hunter	Ferron Ck, Cottonwood Ck	117610 2/	--	242730 3/	30	1984	20, -32	-936.0	-9.0	Good-Poor
NV	Mohave	Colorado River	9542000	1950-84	22410000	5653	1950	74, -36	-646.2	0.0	Good

1/ Percent of Minimum Discharge computed assuming minimum discharge occurs over the course of an entire year. This method tends to overstate the actual expected impacts.

2/ Combined: Ferron Ck 45210 AF/YR (11 yrs), Cottonwood Ck 72400 AF/YR (64 yrs)

3/ Combined: Ferron Ck 38030 AF/YR (1986), Cottonwood Ck 204700 AF/YR (1984)

(VS6-WP-PGC-1326I)

Table 4.3.19

MAXIMUM IMPACT ON GROUNDWATER IN THE PACIFIC NORTHWEST AND INLAND SOUTHWEST

STATE	PLANT	WELL LOCATION	AQUIFER PUMPAGE (AC-FT/YR)	YEARS OF RECORD	RECENT YEAR PUMPAGE (AC-FT)	YEAR	AQUIFER RECHARGE OR YIELD (AC-FT/YR)	MAXIMUM CHANGE IN GENERATION (aMW)	ANNUAL CHANGE IN WATER USE (AC-FT)	PERCENT OF PUMPAGE, RECHARGE, OR YIELD
PACIFIC NORTHWEST										
NV	Valmy	Valmy aquifer near Valmy	--	--	--	--	9000	12, -22	-315.8	-4.0
INLAND SOUTHWEST										
AZ	Cholla	Joseph City, Navajo Co.	20100	1974-83	22000	1983	--	1, -35	-893.8	-4.0
AZ	Springerville	Springerville, Apache Co.	3100	1974-83	3000	1983	--	3, -23	-678.4	-22.6
AZ	Coronado	St. John's, Apache Co.	4300	--	--	--	--	-12	-260.0	-6.0

(VS6-WP-PGC-1326I)

tidal currents. These currents create more flushing action than the power plant pumping (John Oliver, Moss Landing Marine Laboratory, pers. comm., 1987). Changes in operation at this power plant should not have any adverse effect on fish and wildlife resources in the area.

Table 4.3.20

MAXIMUM IMPACT ON GROUNDWATER-SPRINGERVILLE POWER PLANT

STATE	PLANT	WELL LOCATION	BASE GENERATION (aMW)	BASE WATER USE (AC-FT/YR)	CASE GENERATION (aMW)	CASE WATER USE (AC-FT/YR)	% CHANGE IN USE
AZ	Springerville	Springerville, Apache Co.	525	11340	502	10843	-4.3

Table 4.3.21

MAXIMUM IMPACT ON GROUNDWATER IN CALIFORNIA

STATE	PLANT	WELL LOCATION	BASE GENERATION (aMW)	BASE WATER USE (AC-FT/YR)	CASE GENERATION (aMW)	CASE WATER USE (AC-FT/YR)	% CHANGE IN USE
CA	Coolwater	Dagget, San Bernardino Co.	202	4363	172	4126	-15.0
CA	Etiwanda	Etiwanda, San Bernardino Co.	320	6912	285	6156	-11.0

Table 4.3.22

COOLING WATER SOURCE, COOLING SYSTEM TYPE, AND MAXIMUM CHANGE IN GENERATION AT CALIFORNIA THERMAL PLANTS

PLANT	COOLING WATER SOURCE	COOLING SYSTEM TYPE
Contra Costa	Sacramento-San Joaquin Delta	Once-through
Pittsburg	Sacramento-San Joaquin Delta	Once-through, spray channel
Moss Landing	Monterey Bay (Pacific Ocean)	Once-through
Morro Bay	Morro Bay (Pacific Ocean)	Once-through
Encina	Pacific Ocean	Once-through
South Bay	San Diego Bay (Pacific Ocean)	Once-through
Mandalay	Pacific Ocean	Once-through
Alamitos	Los Cerritos Channel (Pacific Ocean)	Once-through
Redondo Beach	Pacific Ocean	Once-through
Huntington Beach	San Pedro Channel (Pacific Ocean)	Once-through
El Segundo	Santa Monica Bay (Pacific Ocean)	Once-through
Ormond Beach	Pacific Ocean	Once-through
Haynes	Long Beach Marina (Pacific Ocean)	Once-through
Scattergood	Santa Monica Bay (Pacific Ocean)	Once-through
Hunters Point	San Francisco Bay (Pacific Ocean)	Once-through

All of the coastal plants entrain fish and other marine organisms in cooling systems. Although the mortality rate of entrained fish can be high, studies by the utilities have found that it is usually not significant at the population level (Southern California Edison, 1982, 1983; Ecological Analysts, Inc., 1981a, 1983b, 1983a, 1981b). In estimates of combined intake losses for all SCE coastal power stations, the utility found that, for several target species, survival with existing cooling water intakes was always over 96 percent (in terms of area-wide, near-shore fish populations of the California Bight) of what would occur without those intakes (SCE, 1983).

Entrainment. Changes in levels of generation are expected to have little influence on existing entrainment. Cooling water pumps at most plants usually operate at full capacity regardless of generation. Pumps are shut down only if the plant is idle for relatively long periods; for this reason, reductions in entrainment may not occur if the plant is being operated cyclically, as it might under an exchange, even though its average generation is less. If substantial reductions in generation occur, one of several pumps may be turned off (Bernard Rapan, personal communication, February 1986).

Two California plants have been identified as having a potentially significant entrainment problem. Entrainment of striped bass larvae and juveniles at the Pittsburg and Contra Costa Plants has led to significant mortality (Ecological Analysts, Inc., 1981a, 1981b). Studies conducted to satisfy section 316(b) of the Amendments to the Federal Water Pollution Control Act of 1972 (PL-92-500) for these plants document entrainment mortalities by month over a 2-year period. Monthly average plant capacity factors and water volume pumped for cooling are also documented for this period. Theoretically, it would be possible to establish a relationship between generation and cooling water volume. Changes in generation could then be used to predict changes in cooling water volume, and these in turn translated into changes in entrainment mortalities. There are certain assumptions and limitations involved in this process:

- Cooling water volume is not directly related to generation. Unless variable speed pumps are installed, pumps operate at full capacity regardless of generation. However, over long periods of time (e.g., a year) there is usually a statistically significant relationship between generation and cooling water volume that varies within certain limits.

- Entrainment mortalities are not directly related to cooling water volume. Other factors come into play, such as water temperature, temperature increase across the condensers, and the density and distribution of entrainable life forms in the immediate vicinity of the intake structure.

Linear regression analysis was completed for cooling water volume and level of generation at the Pittsburg and Contra Costa Plants using data from Ecological Analysts Inc. (1981a, 1981b). This analysis indicates that changes in generation do produce changes in cooling water volume.

However estimates of the cooling water changes are statistically significant only for changes in generation larger than those accompanying policy/capacity shifts considered in this study. Therefore it is not possible to conclude whether there are any changes in entrainment effects.

Cooling System Wastes. Substances added to condenser cooling waters to minimize corrosion, deposits, and biological growth may be toxic if released to ground or surface waters (Elonka, 1963). Power plant operations may also impair water quality by discharging cooling system water and boiler water containing dissolved solids. The impact depends upon site characteristics. Some generating units recycle these waters until they are evaporated, so no wastewater is released. This effect is considered comparatively minor and is not analyzed in this EIS.

Disposal of combustion wastes can also affect water quality. Water can be consumed if ash and slag wastes are slurried or sluiced to settling basins and storage ponds. Net water consumption is greatest if this water evaporates and least if it is released to surface waters (Table 4.3.23). Water use is higher in facilities that handle each combustion waste separately.

Wastewater may be released through a breach of storage dikes, overflow, or percolation to groundwater (Dvorak et al., 1978). Unintentional discharges should not occur if the facility is designed and operated in conformance with the Effluent Limitations Guidelines, New Source Performance Standards (NSPS), and provisions of the Resource Conservation and Recovery Act (Soholt et al., 1980; Hittman, 1974). Runoff from onsite waste ponds is unlikely if they are lined and if protective dikes are built high enough (Lewis et al., 1978). Most basins are designed to contain runoff from a once-in-10-years storm (Soholt et al., 1981). Excessive rainfall and/or dike failure may cause spills (Dvorak et al., 1978), but the wastewater would likely be contained on-site. Seepage can contaminate soil and groundwater, especially if waste is deposited as a slurry. However, storage ponds are lined in order to minimize such hazards.

Table 4.3.23

WATER REQUIREMENTS FOR WASTE DISPOSAL
AT A COAL-FIRED POWER PLANT

TYPE	Water (10^3 Gal/Average MW) No Recycling	Recycling
Bottom Ash	47.3 1/	5.1 3/
Fly Ash	184.2 1/	19.7 3/
Lime Sludge	147.4 2/	26.9 3/
Limestone Sludge	184.2 2/	33.8 3/

1/ Assumes slurry with 30 percent solids by weight.
2/ Assumes sludge with 30 percent solids by weight.
3/ Assume 70 percent solids by weight.

4.3.3.2 Sensitivity and Other Analyses

The sensitivity analyses which were performed showed some situations where water-related impacts of Western coal, oil, and gas-fired generation could be different than under the assumptions used for the original analysis.

Higher California Gas Prices. If Intertie capacity is increased and California gas prices are higher than assumed in the original analysis, more PNW coal-fired generation is operated, relative to that shown in the original analysis, in each of the future years of the analysis to displace larger amounts of PSW generation. Thus water consumption impacts at PNW coal plants, all of which have closed-cycle cooling systems, may increase. However, the extremely conservative analysis of water consumption impacts for these plants based on the original analysis showed that such impacts would be small. Environmentally significant differences in water consumption in the event of higher California gas prices do not seem likely. The sensitivity analyses did not specifically address ISW coal or oil and gas-fired plants, so conclusions cannot be drawn about the significance of changes in their water consumption. With increased California gas prices, ISW coal plants may also operate more. But their operating levels are still likely to be lower than if PNW exports did not increase because of the availability of more Intertie capacity. To this extent, water-related impacts from ISW coal plants may not be as large as they might have been without increased Intertie capacity. Generating plants in California, many of which use once-through cooling systems, would tend to operate less with a high gas price than projected under the original analysis. Thus, a reduction in the potentially significant entrainment problems at the Pittsburg and Contra Costa plants is more likely if high gas prices evolve in comparison to the results of the original analysis.

Higher California Loads. For the high California load sensitivity analysis, similar effects to those described above for the high California gas price sensitivity analysis would occur, but they would be largely limited to early in the study period. The effects of fairly large increases in PNW coal plant generation and PNW exports above the original analysis, appear in 1993 of the years looked at in the analyses, but largely disappear in 1998 and 2003.

Lower Pacific Northwest Loads. Finally, in the situations studied for the sensitivity analysis in which Intertie capacity increases are assumed to coincide with lower PNW loads than under the original analysis, quite large increases in PNW exports of electric energy, relative to that projected in the original analysis, occur. The amount of these exports increases over time. This situation could result in some substantial benefits related to excess aquifer pumpage and entrainment of aquatic organisms by California and ISW coal, oil, and gas-fired power plants. If firm power contracts were signed under this situation, allowing deferral of new power plant development, scarce water resources in California and the ISW could be reserved for other uses for a period of time. In this sensitivity analysis, the exported energy comes predominantly from hydro resources, so there would be very little change in water-related impacts of PNW coal plants.

Assured Delivery Alternatives 1, 2, and 3. These three cases enhance net export of energy to California, relative to the existing contracts, when a given Intertie size is assumed. Therefore, relative to Existing Contracts, they offer some potential for relief of water-related impacts of ISW coal plants and problems related to entrainment at certain California generating plants. Water related impacts of Pacific Northwest coal plants seem negligible from the analysis earlier in this chapter since operation increases are small.

Oil & Natural Gas

The oil and natural gas industries have potential for significant adverse effects on ground and surface waters and aquatic life. Many of these potential effects result from unplanned events such as accidental spills or equipment failure. Although potential water quality and aquatic life impacts resulting from the provision of fuel oil and natural gas for electric power generation are significant, it is difficult to tie changes in generation at Western oil and gas-fired power plants resulting from BPA's Intertie decisions to changes in operation of specific oil and gas industry facilities. Therefore, a quantitative analysis of the impacts of BPA's Intertie decisions on water quality and aquatic life effects of the oil and gas industries within this EIS is precluded. The rest of this section discusses some of the general environmental effects of oil extraction, transport, storage, refinement, and combustion.

The environmental effects of oil extraction depend on local site characteristics and the specific drilling method employed. Exploration can significantly affect water quality. Groundwater may supply solvent for drilling muds and for well injection. Aquifers may be contaminated if drilling muds, fluids, brines, and hydrocarbons escape into porous formations. However, casing and other techniques protect aquifers, greatly reducing the risk of contamination. Oil spills may occur at the well-head; however, these are typically confined, low-volume spills which do not seriously contaminate surface waters (Garcia et al., 1983).

Offshore rigs can leak or spill oil into the water. Offshore extraction discharges an average of 0.355 tons of organic chemicals per aMW generation (Hittman, 1974). Drilling brines released to saline or nonpotable waters are assumed to be nonpolluting (SPPP, 1975). No residuals are discharged when natural gas is extracted (Hittman, 1974). Onshore extraction yields both nondegradable organics and brine. Organics are discharged at the same rate under both controlled and uncontrolled extraction--0.043 tons/aMW.

Oils in aquatic environments may float, be suspended in the water column, dissolve, or settle on the bottom as sludge. Oil may have acute, lethal, or long-term, sub-lethal effects on aquatic organisms. Spills can cause immediate death among a wide variety of invertebrates and fishes, or may interfere with cellular and physiological processes, reduce food resources and habitat, alter behavior, cause reproductive failure, or increase vulnerability to predation and disease. Oil may persist for a long time in bottom sediments, disturbing bottom-dwelling communities and possibly entering aquatic foodchains. Free oil can coat fish gills and interfere with respiration. It may also coat and kill aquatic plants and birds (McKee and Wolf, 1963).

Oils may reduce populations of phytoplankton and kelp (Gordon and Prouse, 1973; Wilber, 1968). Responses by fish to oil include delayed hatching, deformation of larvae, and disruption of feeding, among others. Crustaceans and mollusks show similar responses.

Fish sensitivity depends at least partly on the time and location of the spill (which affects the probability of direct contact with spilled oil) as well as on the lifestage and the habitat affected (Beak Consultants, 1975). The majority of midwater or bottom-dwelling marine fish seldom directly contact spilled oil. However, intertidal and shoreline fish (including young salmonids) are vulnerable to the toxic effects of water-soluble pollutants from spills near intertidal, beach, or protected areas. Fish may be less vulnerable than other marine organisms because of their mobility and mucous coating, but they may suffer toxic effects on contact and by feeding on contaminated organisms. According to the EPA (1976), oils of any kind can kill organisms by coating gills, increasing biochemical oxygen demand, or asphyxiating the organism. In open water, spawning fish are most vulnerable to oil contamination.

The most significant aquatic impacts from oil transport arise from dredging waterways for marine vessel passage and from spills during fuel storage and handling, rail and highway accidents, and pipeline ruptures. Dredging and the disposal of dredging waste can have significant effects on rivers and estuaries. Short-term impacts include altered estuarine environment; decreased dissolved oxygen; increased river temperature and turbidity; nutrient releases from sediments (which may stimulate growth of phytoplankton and algae); and releases of oils and grease. Temperature and turbidity changes can be significant during biologically sensitive times, such as spawning and salmonid migration. Dredging may also reduce fish nursery areas.

Minimal impacts arise from rail and truck transport under normal operating conditions. At most, surface water may be contaminated by runoff with high concentrations of residues from pollutants deposited on and near roads and tracks by pollutants from automobiles and trains.

Pipelines also affect water quality and aquatic life at stream crossings and during hydrostatic testing (Garcia et al., 1983). Once constructed, pipelines cause few impacts during routine operation. However, pipelines at stream crossings may be washed out or undercut by bank erosion, spilling oil into aquatic communities. Water used for hydrostatic testing may contain toxic substances, which may be discharged into surface water. Small undetected leaks in a buried oil pipeline can seriously contaminate groundwater aquifers. Submarine pipelines are not known to create significant environmental damage. However, leaks or breaks can cause serious local pollution problems (EPA, 1976). Unburied underwater pipelines may constitute a barrier for bottom-dwelling organisms.

Oil is stored at refineries in large aboveground or underground tanks. Spills constitute the major potential aquatic impact (discussed above).

Usually provisions are made for containment of spills. It is not likely that small changes in the level of refinery operation would affect the likelihood of a spill. Gas is delivered to plants via pipeline, and storage tanks are usually unnecessary (Dvorak et al., 1978). The potential for gas spills is negligible (Garcia et al., 1983).

Water quality may be affected by atmospheric emissions, thermal wastewater, disposal of solid wastes, discharge of waste water, and oil spills. A typical refinery wastewater effluent has varying amounts of Biological Oxygen Demand (BOD) and Chemical Oxygen Demand (COD) which reduce available oxygen, and contains varying amounts of ammonia, hydrogen sulfide, phosphorus, phenol, oil, and suspended and dissolved solids. These discharges are subject to regulation.

The petroleum industry uses substantial amounts of water in refining crude oil. By comparison, the amount used in exploration for drilling wells and in operating gas-fired plants is insignificant (EPA, 1973). The effects of thermal emissions from cooling towers are the same as those discussed above for coal plants. An average oil refinery produces an estimated four tons per day of solid wastes, containing many substances appearing on the U.S. EPA toxic substances list. Solid wastes are disposed of in land fills, sometimes after incineration, and may affect aquatic environments through runoff or leaching to the groundwater. However, such runoff and percolation are controlled by Federal and State standards and standard industry practice in newer plants, and controls are usually effective.

Water quality problems resulting directly from operation of oil- and gas-fired power plants are minimal. However, oil and gas generation can lead to substantial consumption of ground and surface water for cooling, or to the entrainment of fish and the discharge of heated waters, as discussed earlier in this section. Impacts from limestone preparation and storage at oil plants, and from condenser cooling at oil and gas-fired plants, are the same as those discussed above for coal plants. The lower sulfur levels involved in burning oil (relative to coal) result in less scrubber sludge and ash waste (Dvorak et al., 1978). Gas combustion produces none of these wastes. Impacts of gas combustion are generically similar to but much less than those described for coal.

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4.3.4 VEGETATION AND WILDLIFE

Through their effects on the operation of thermal plants, Intertie decisions have the potential for impacting vegetation and wildlife. This section considers the effects of changes in the operations of coal, oil, gas, and nuclear generation facilities on these environmental factors.

Coal Mine Effects. Strip-mining involves excavation, backfilling, and grading that removes vegetation from large tracts. This affects wildlife primarily through loss and disturbance of habitat. Displacement of species may cause species to move into adjacent areas, where overcrowding and competition for limited resources may increase mortality, especially in critical habitat areas. (Other sources of information on wildlife impacts include an annotated bibliography by Rolston, Hilbut, and Swift (1977), and a summary of practices to protect fish and wildlife on mined lands in Utah by Procter et al. (1983)).

Uncontrolled runoff and the resulting soil erosion may contaminate surface and groundwaters, altering species composition and soil characteristics. Accidental fires may temporarily affect vegetation and wildlife. Hauling of coal and overburden may result in noise, dust, air emissions, soil compaction, and road-kills.

Exploration and mine development involve the use of drill rigs and test pits which have localized impacts on soil, vegetation, and wildlife due to grading, clearing, noise, dust, runoff, excavation, and related activities, but on a far smaller scale than actual mining operations. By delaying mine development, the Intertie could have a beneficial effect. Mines will operate within standards set by the U.S. Department of the Interior and other governmental standards and therefore will not affect Federally listed threatened and endangered species. (See Appendix 3.) Therefore, mine operation's will have no impacts on threatened and endangered species or their habitat.

Reclamation attempts in the Northern Great Plains and Rocky Mountains have typically succeeded in establishing nonnative plant cover. The reclamation of Western coal mines is hampered by a combination of nutrient-poor soil and arid or semi-arid climate. All reclamation efforts to date require high inputs of energy, manpower, fertilizer, and water. In effect, these reclamation activities have been short-term in nature and have required high maintenance levels (Curry, 1980; R. Giurgevich and M. Moxley, Wyoming Department of Environmental Quality, personal communication, 1985). To be successful, reclamation requires 15 years or more for long-lasting results. (NAS, 1974; Aldon, 1978).

Only three mines are expected to produce more coal under any IDU alternative than under the No Action Alternative. These are the Rosebud Mine in Montana, and the Belle-Ayre and Bridger Mines in Wyoming.

These mines, on Federal lands, are operating under permits granted by the Office of Surface Mining (OSM). Permits require compliance with the National Environmental Policy Act (NEPA), including a requirement dealing with threatened and endangered species. The U.S. Department of the Interior must approve the permit and assure compliance with all Federal laws including the Threatened and Endangered Species Act (Holbrook, 1987, personal communication). These permits apply only to a certain surface area; if expansion is necessary, a new permit must be obtained. All NEPA requirements and other applicable laws such as the Threatened and Endangered Species Act must be reviewed again.

The Rosebud Mine is operating under permit numbers MT-002 A, B, C, D and E; The Belle-Ayre Mine permit number is WY-006; the Bridger Mine permit number is WY-001.

Since these permitting requirements and resulting certification are mandated, it is BPA's opinion that none of the actions covered by the IDU EIS would cause impacts to any threatened or endangered species or other species from operation of these mines.

Coal-Fired Plants Effects

For existing coal-fired plants, impacts can occur from increased water withdrawals for cooling or increased return-water temperature. Existing coal-fired plants in the Pacific Northwest, Inland Southwest, and Rocky Mountains were evaluated within the EIS for the potential to exceed the No Action Alternative. Only the Colstrip and Jim Bridger coal-fired plants may exceed that level.

Water is withdrawn from the Green River for cooling the Jim Bridger plant. There are two fish species listed as threatened and endangered in the Green River: the humback chub and the Colorado squawfish. Table 4.3.18 indicates that the Jim Bridger plant will only have a 2 percent change in water use. It also shows that the Green River has a "good-poor" record rating, which means the accuracy of the discharge measurements is less than 10 percent of the true value. Based on these values a change of 2 percent would be considered unmeasurable and insignificant. Therefore, due to the minor amount of change in water withdrawals from the Green River, the proposed actions will not affect any threatened and endangered fish species or any other fish species.

Table 4.3-18 indicates that virtually no measurable change in water use would occur at the Colstrip plant. Furthermore, no threatened and endangered fish species are listed for the Colstrip plant. Therefore, the Intertie proposals alternative would not affect any fish species in relation to the Colstrip plant.

Coal-fired power plant emissions may affect wildlife directly and indirectly. The direct effects of these emissions on wildlife involve acute or chronic exposure to gaseous or particulate substances contained in stack gases. Animal response to air pollution varies seasonally and in relation to habitat quality, sex, and age. Indirect effects on wildlife occur through contaminated food sources and habitat. Species that are most susceptible to such indirect effects include eagles, ospreys, kingfishers, and other fish-eating birds; bears; and water-associated mammals such as mink, beaver, and river otters. However, all projected changes in ambient air quality for the Pacific Northwest and Inland Southwest are so small that changes in effects on vegetation and wildlife of air pollution would be negligible (see 4.3.2).

Studies of threatened and endangered species affected by coal-fired plants in California and the ISW include analyses of the the bald eagle, the American peregrine falcon, the black-footed ferret, the humpback chub, and the Colorado squaw fish. Dvorak et al. (1978), and Dvorak and Pentacost (1977) cite modeling studies to suggest that trace elements may have relatively little impact on terrestrial organisms and their communities, provided that the power plants meet New Source Performance Standards (NSPS) for particulates, and provided that tall stacks are used.

Of the primary gaseous pollutants, SO_2 is likely to have the greatest impact on terrestrial ecosystems, particularly on vegetation. Gases such as SO_2 and NO_2 can damage plants by destroying all or part of their foliage, reducing vegetation biomass and species diversity, or damaging reproductive ability (Gordon and Tourangeau, 1974). It has been determined that the proposed alternatives will produce no significant change in air quality and therefore will have no effect on threatened and endangered species.

Acid deposition may also affect terrestrial environments and wildlife. The impacts of acid deposition are reviewed in Dvorak et al. (1978), Gage (1980), Peterson and Adler(1982), and Newmann (1980). The primary geographic area of concern for wildlife is the Sierra Nevada of California, where acid deposition may result in substantial species shifts. Bark beetle attacks in ponderosa pine forests, for example, are more prevalent and devastating when trees are injured by oxidants (Wood, 1973). Parts of Arizona, New Mexico, Washington, Oregon, and Idaho may also be subject to acid deposition. Steep slopes with thin, rocky soils, and riparian habitats are particularly vulnerable locations (Peterson and Adler, 1982).

Acidification of lakes and streams may change the composition and structure of aquatic vegetation, affecting riparian wildlife, particularly amphibians. Acid deposition has been shown to produce changes in soil pH and water chemistry to such a degree that aquatic and terrestrial producers have drastically declined, resulting in subsequent loss of primary and secondary consumers (Gage, 1980).

Because terrestrial vertebrates are protected by feathers, fur, or scales, the direct effects of acid deposition are minimal. Acute direct effects on animals are restricted to areas very near point sources of the acidifying air pollutants. Such effects as irritation of eyes or respiratory tract (Newmann, 1980) can lead to emigration, abnormal behavior, or reductions in inter- and intra-specific competitiveness (Chilgren, 1978). According to Table 4.3.14., acid dispositon due to changes in plant operations would be small and affects to wildlife and vegetation would be negligible.

Chemicals added to cooling-tower waters to prevent corrosion in the pipes can be released with drifting vapor from cooling towers, and may be deposited on the ground nearby. Trace amounts of heavy metals, including arsenic, cadmium, lead, chromium, and mercury, have also been found in tower drift. Salt drift from plants cooling with ocean water may lead to vegetation shifts where salt-intolerant species are prevalent (BSAI, 1982).

Impacts of diverting water for use in coal plants depends on the source of the water, particularly if diverted from surface drainages. There may be some reduction in the amount of riparian vegetation, a shift in composition to less moisture-dependent species, and a reduction in the habitat value to wildlife. This would be of greatest concern in arid environments.

Where spills or seepage from coal plant waste storage ponds contaminate soil or groundwater, vegetation may accumulate toxins and pass them on to herbivores. Dvorak et al. (1978) discuss the adverse effects of unlined ash and waste-disposal sites on groundwater and terrestrial food chains. Leaching from lined sites is negligible (Soholt et al., 1981). The Resource Conservation and Recovery Act forbids placing waste storage facilities in environmentally sensitive areas (e.g., wetlands), in critical habitat for endangered species, in seismically active areas, or within recharge zones of sole-source aquifers (Soholt et al., 1981). Waste-handling facilities cannot discharge pollutants into surface waters in violation of the requirements of the National Pollution Discharge Elimination System established through the Clean Water Act. Therefore, only accidental spills or poorly operated facilities are likely to affect vegetarion and wildlife.

Disposal ponds may attract waterbirds, especially if there are nearby sources of food. Birds using these ponds for resting and feeding can ingest potentially toxic particles or slag. Surface-feeding waterfowl are most vulnerable to ingesting slag, which may contain beneficial as well as detrimental trace metals. Birds may also collide with transmission towers and lines situated close to the ponds. There will be a slight change in the amount of ash deposited into disposal ponds as a result of this project. (Further discussion of solid waste disposal is discussed in Table 4.3.15.)

Oil-Fired Power Plant Effects. Most oil-fired power plants in the study area are located in coastal or estuarine environments, both important habitat types for fish and wildlife. While terrestrial accidents from oil transport may have only localized impacts on the soil and surrounding vegetation and environment, spills near tidal marshes, tide flats, or riparian areas can have direct and indirect effects on vegetation and wildlife throughout the area of the spill. Short- and long-term effects of oil spills on wildlife are discussed by Garcia et al. (1983), the National Research Council (1980), and Dieter (1976), among others. Albers (1979) and Lindstedt-Silva (1979) describe impacts associated with oil spill cleanup operations, which may be as harmful to wildlife as the spill itself, depending upon the disposal agents used.

Air pollutants emitted by oil or gas plants affect wildlife and their habitat much as those emitted by coal plants, but the magnitude of these impacts are much smaller in most cases, because of the lower level of emissions from oil/gas plants. Effects on vegetation and wildlife related to air quality from changes in operation of oil/gas plants are negligible since the projected ambient air quality differences (see 4.3.3) are so small.

BPA's original request for threatened and endangered species from U.S. Fish and Wildlife Service (USFWS) listed nine gas- and oil-fired plants, identified through individual plant modeling, that exhibited changes potentially exceeding the No Action alternative. However, the study model proved to be incompatible with the overall systems modeling for the EIS. Oil- and gas-fired plants were consequently grouped by air quality basins for a compatible analysis. The final study indicated that air pollution would be reduced slightly in California because less gas and oil would be used.

The USFWS in California identified habitat modification, air quality, and oil spills as primary concerns associated with oil- and gas-fired plants in California. Any increases in air pollution and oil spills could potentially affect the variety of threatened and endangered species that occur in the area of the power plants.

These plants are capable of burning either natural gas or oil. In recent years, they have used natural gas most of the time. The EIS concludes that the potential for gas spills is negligible. Since IDU Action alternatives generally reduce oil- and gas-plant operation in California, the potential for oil and gas spills is no higher than that for the No Action alternative.

Since no construction is planned and since plants will continue to operate within design limits, with insignificant changes in air quality and little likelihood of oil spills, no impacts on threatened and endangered species, other species, or their habitat are expected.

Nuclear Plant Operations. Effects from nuclear power plants depend on the plant's location and cooling system used. Nuclear plants produce radioactive waste, radioactive emissions, waste heat, and chemical residuals from the cooling water system. The impact of nuclear power plants on terrestrial vegetation is most likely to occur through the deposition of drifting steam that is released from cooling towers. This drifting steam can damage nearby vegetation, especially if salt water is used for cooling. Improved engineering design can control the problem through the use of baffles or drift eliminators, which reduce the amount of water droplets in the air stream.

Thermal discharges from once-through cooling systems near estuaries could affect terrestrial wildlife and vegetation through a change in distribution of some marine fish. Waste heat released in other areas does not appear to affect wildlife or vegetation.

4.4 NEW RESOURCES

OVERVIEW AND SUMMARY

This section describes the potential effects of Intertie decisions on the development of new resources in the Pacific Northwest, California and the Inland Southwest. New resource development in Canada would not be affected, assuming Canada receives no firm access to the Intertie.

First, a quantitative analysis of the effects of the proposed actions and their alternatives on new resource development in the Northwest is presented. This is followed by a qualitative analysis of the expected impacts on resource development in California and the Inland Southwest.

Generally speaking, the liberal granting of firm access to the Intertie would encourage establishment of new firm contracts which, in turn, encourage resource development in the Northwest and allow resource deferrals in California and the Inland Southwest. The amount of effect and types of resources developed depend on the nature of assumed firm contracts. The size of the Intertie (independent of potential new contracts) has little impact on resource development. New resource development is dependent upon new contractual arrangements. Capacity/energy exchange contracts tend to slow resource development in all regions, while power sales from the Northwest tend to increase Northwest resource development, but slow resource development in the Inland Southwest and California. Scenarios in which utilities other than BPA bear major responsibility for resource development emphasize the construction of coal and hydro plants in contrast to nuclear facilities.

4.4.1 METHOD OF ANALYSIS

For the quantitative analysis of Pacific Northwest resource development, BPA's Least Cost Mix Model (LCMM) was run for each of several contract configurations, assuming first Existing, and then Maximum, Intertie capacity. This method resulted in the production of a variety of new resource portfolios, depending on the amount of load to be served by Northwest resources and the types of resources assumed available for development (i.e., Federal versus non-Federal).

The analysis of the effects of Intertie decisions on the development of new resources is organized somewhat differently than the analyses presented elsewhere in this chapter. This difference is necessary in order to take account of the fact that the access proposed under the IAP for new resources is more restrictive than access for existing resources. New resources may gain access only if they are needed to sustain a contract originally established on the basis of an existing resource surplus. Unrestricted Access for firm sales was modeled as an alternative to the Proposed Access condition only for the new resources analysis. The Unrestricted Access condition was modeled by assuming Pacific Northwest resources could be built to meet an additional 2,000 MW of firm sales to California.

The effect of Intertie capacity on new resource development was evaluated at both the Existing and Maximum capacity levels. The effect of formula allocation on new resources was not evaluated since it would not be expected to have an effect because it would not be economic to build new resources for the purpose of making nonfirm sales.

Contract conditions were felt to be the most significant factor influencing new resource development. The analysis considered the effects of the Existing Contracts, Federal Marketing and Assured Delivery conditions. These conditions were evaluated at both Existing and Maximum capacity. In addition, three variations of the Assured Delivery case were analyzed. Assured Delivery Alternative #1 included increased long-term power sales and seasonal exchanges with a decrease in capacity/energy exchanges. In Assured Delivery Alternative #2, the remainder of the capacity/energy exchanges was replaced by seasonal power exchanges, with everything else remaining as in Alternative #1. Assured Delivery Alternative #3 was an intermediate case between Alternatives #1 and #2. Finally, a contract configuration including a large (1,350 MW) Firm Displacement (FD) power sale replaced the capacity/energy exchanges in the original Assured Delivery configuration. All of these variations on Assured Delivery, as well as the Existing Contracts, Federal Marketing and Original Assured Delivery contract configurations, were modeled at Maximum capacity. Table 4.4.1 summarizes the cases analyzed. Data on new resource effects are presented by resource type (conservation, nuclear, coal, hydro and total) for each of the four study years (1988, 1993, 1998, and 2003) for those cases involving Existing capacity. For the Maximum capacity cases, only the years 1993, 1998 and 2003 are presented, since Intertie upgrades would not occur until after 1988.

Table 4.4.1

SUMMARY OF ANALYSES FOR NEW RESOURCE IMPACTS

	Existing Capacity	DC Upgrade	Maximum Capacity
Existing Contracts	X		X
Federal Marketing	X		X
Assured Delivery	X		X
1350 MW Firm Displacement Sale (without Federal back-up)			X
Alternative #1	X	X	
Alternative #2			X
Alternative #3		X	X
Unrestricted Access			X

The resource stack used for the Final EIS analyses differs in some respects from that included in BPA's 1987 Resource Strategy. The 1987 Resource Strategy resource stack was not revised for the 1988 Resource Program. The 1987 Resource Strategy stack contains 924 MW of generating resources (consisting of 124 MW of hydro resources, 200 MW of imports, and 600 MW of combustion turbines) and a potential for 1,392 average MW of new conservation (excluding the Model Conservation Standards) achievable between 1988 and 2005, all of which is more cost-effective than WNP-1 and WNP-3. The resource stack used for the Final EIS analyses excluded new combustion turbines because they are only cost-effective as a base resource in a scenario in which they are used for firming nonfirm energy, i.e., using a combination of nonfirm energy, when available, and operation of combustion turbines when nonfirm energy is not available to meet a firm load. Had large amounts of combustion turbines been used in the resource stack for the IDU analyses using SAM, it would have been difficult to discern from the analyses effects resulting from changes in Intertie size, formula allocation, and contract conditions from those effects attributable to firming nonfirm energy. In the Final EIS analyses, imports were used in the modeling as resources to make up deficits for short periods prior to addition of large resources; long-term use of imports as a resource, as included in the 1987 Resource Strategy resource stack, was not utilized in the EIS analyses. The Final IDU analyses also assumed a lower overall rate of ramping in cost-effective conservation than that deemed achievable in the 1987 Resource Strategy. In the Final EIS analyses, a total of 815 MW of conservation was brought on through the end year of the analysis, 2006.

The differences in the resource stack would not substantively affect the overall conclusions concerning the marketing of power, the availability of power to various markets, or the environmental effects described in parts 4.1 through 4.3 of this Chapter. However, there may be some short-term effects in some years, principally because if the 1987 Resource Strategy resource stack had been used, WNP-1 and WNP-3 would have been delayed. WNP-3 would have come on line later in the period covered by the analyses, and WNP-1 may have been delayed to beyond 2006. Since WNP-1 and WNP-3 are large resources, deficits, which the SAM covers by imports, may occur in the model prior to when these large resources come on line, and surpluses may occur for a short time thereafter. With the 1987 Resource Strategy resource stack, conservation and smaller resources would have delayed WNP-1 and WNP-3, and such "bumps" in the load/resource balance would have occurred in later years of the analyses. Since data were reported elsewhere in this EIS only for selected years, some of the apparent large increases in nuclear plant operation and compensating reductions in operation of other types of generation for 1998 and 2003 would not have been observed.

The qualitative analysis of resource development in California consisted of a review of published planning documents of California utilities, including Common Forecasting Methodology VI submittals to the California Energy Commission, to determine the extent to which the utilities planned to rely on Pacific Northwest power supplies. These plans were evaluated with respect to the potential effects of alternative levels of Intertie sales and alternative types of contracts. Corresponding analyses were done for the Inland Southwest and British Columbia.

4.4.2 RESOURCE DEVELOPMENT IN THE PACIFIC NORTHWEST

Intertie capacity had virtually no effect on the development of new resources in the Northwest, regardless of contract configuration for the Existing, Federal Marketing and Assured Delivery contracts. These comparisons are displayed in Table 4.4.2 and Figure 4.4.1.

Data pertaining to the effect of contract configurations, given Maximum capacity, are displayed in Table 4.4.3. New resources in the Northwest increase throughout the study period in all cases. The presence of capacity/energy and seasonal exchanges in the Federal Marketing case produces a lower need for Northwest new resources than is the case for Existing Contracts. The opportunity for the Northwest to exchange capacity for energy and summer capacity for winter capacity allows deferral of otherwise needed new resources. The Assured Delivery case results in modest increases in the need for new resources in 1998 and 2003 relative to the Existing Contracts case. Substantial increases in the need for new resources occur for Assured Delivery Alternatives #1 and #2. This is due to removing the capacity/energy exchanges and including power sales with higher load factors. An even larger increase in the need for new resources is present for the 1,350 MW FD configuration because this long term power sale would replace contracts assumed to convert to exchanges. By far the largest increase in the need for new Northwest resources occurs in the Unrestricted Access case.

The Unrestricted Access case would not have any noticeable effects in British Columbia, since BC Hydro's access to the California or Pacific Northwest markets would not change substantially. However, it is possible that increased levels of firm contract sales by Northwest utilities could reduce the amount of Intertie available for nonfirm sales from BC Hydro.

In addition to the substantial variation in the amounts of new resources required under the contract configurations, there were significant differences in the types of resources that would be developed. In the Existing Contracts case, resource needs are met primarily with conservation and, to a much smaller extent, hydro, until late in the study period when substantial amounts of nuclear generation would be brought online. A similar pattern exists for the Federal Marketing and Assured Delivery cases with Federal Marketing requiring somewhat less and Assured Delivery somewhat more nuclear capacity than the Existing contracts case. Assured Delivery Alternative #1 requires a significant additional amount of nuclear generation beyond the original Assured Delivery case later in the study period, with Alternative #2 requiring still more nuclear capacity. In fact, the nuclear capacity required for Alternative #2 is the largest of the nuclear capacity requirements of any of the cases analyzed.

Table 4.4.2

IMPACT OF INTERTIE CAPACITY AND FIRM MARKETING ON NEW RESOURCE DEVELOPMENT
(aMW)

	Resource Type											
	Conservation		Nuclear		Coal		Wind		Hydro		Total	
	Intertie Capacity		Intertie Capacity		Intertie Capacity		Intertie Capacity		Intertie Capacity		Intertie Capacity	
Year/Contract Option	Existing	Maximum	Existing	Maximum	Existing	Maximum	Existing	Maximum	Existing	Maximum	Existing	Maximum
1988												
Existing Contracts	5	5	0	0	0	0	0	0	0	0	5	5
Federal Marketing	0	0	0	0	0	0	0	0	0	0	0	0
Assured Delivery	0	0	0	0	0	0	0	0	0	0	0	0
1993												
Existing Contracts	157	157	0	0	0	0	0	0	39	39	196	196
Federal Marketing	0	0	0	0	0	0	0	0	0	0	0	0
Assured Delivery	0	0	0	0	0	0	0	0	0	0	0	0
1998												
Existing Contracts	378	382	129	125	0	0	0	0	124	124	631	631
Federal Marketing	0	0	-85	-85	0	0	0	0	0	0	-85	-85
Assured Delivery	6	6	+125	+125	0	0	0	0	0	0	+131	+131
2003												
Existing Contracts	646	646	1014	1004	0	0	0	0	124	124	1784	1784
Federal Marketing	0	0	-85	-85	0	0	0	0	0	0	-85	-85
Assured Delivery	+17	+8	+114	+123	0	0	0	0	0	0	+131	+131

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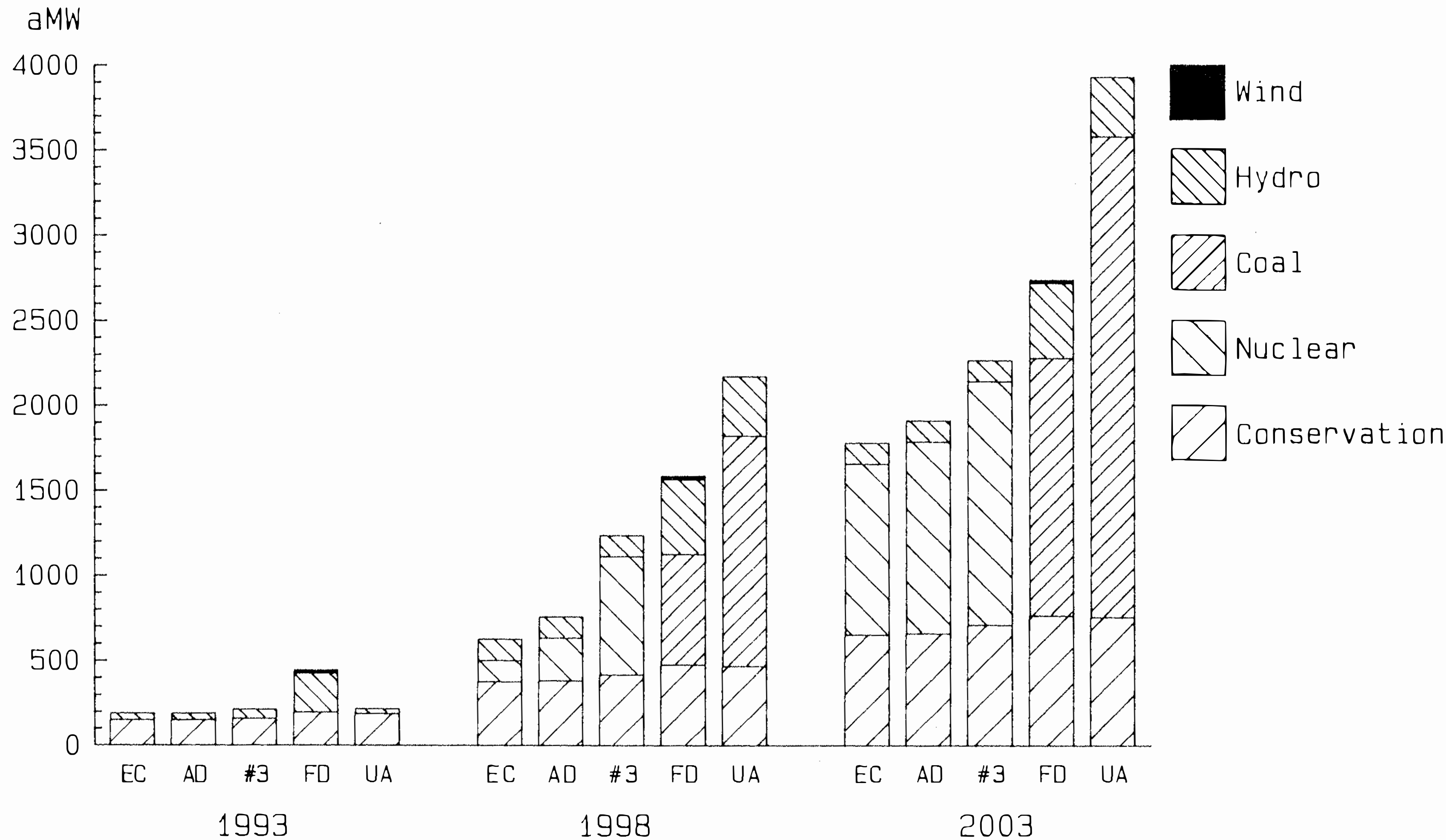
Figure 4.4.1
Impacts of Different Sets of Long-Term Contracts on New Resource Development



* 1988 effects too small to be illustrated

EC=Existing Contracts
AD=Assured Delivery
#3=Alternative #3

FD=1350 Fed. Mktg. Sale
UA=Unrestricted Access

Table 4.4.3

IMPACTS OF LONG-TERM FIRM CONTRACTS CONFIGURATIONS
ON NEW RESOURCE DEVELOPMENT 1/
(aMW) 2/

	Conservation	Nuclear	Coal	Wind	Hydro	Total
1993						
Existing Contracts	157	0	0	0	39	196
Federal Marketing	0	0	0	0	0	0
Assured Delivery	0	0	0	0	0	0
Alternative #1	+9	0	0	0	+12	+21
Alternative #2	+12	+15	0	0	+66	+93
Alternative #3	+10	0	0	0	+14	+24
1350 MW FD Sale	+46	0	0	+20	+189	+255
Unrestricted Access	+37	0	0	0	0	+37
1998						
Existing Contracts	382	125	0	0	124	631
Federal Marketing	0	-85	0	0	0	-85
Assured Delivery	+6	+125	0	0	0	+131
Alternative #1	+36	+394	0	0	0	+430
Alternative #2	+47	+463	0	0	+43	+553
Alternative #3	+41	+568	0	0	0	+609
1350 MW FD Sale	+99	-125	+648	+20	+315	+957
Unrestricted Access	+90	-125	+1,353	0	+224	+1,542
2003						
Existing Contracts	656	1004	0	0	124	1784
Federal Marketing	0	-85	0	0	0	-85
Assured Delivery	+8	+123	0	0	0	+131
Alternative #1	+52	+378	0	0	0	+430
Alternative #2	+63	+447	0	0	+43	+553
Alternative #3	+59	+426	0	0	0	+485
1350 MW FD Sale	+114	-1,004	+1513	+20	+315	+958
Unrestricted Access	+104	-1,004	+2,818	0	+224	+2,142

1/ Assumes Maximum capacity except for Alternative #1 which was not run at Maximum capacity. Existing capacity was used for the Alternative #1 results. Intertie size has little effect on the results of these analyses, however.

2/ The results shown for Existing Contracts indicate the amount of new resource development expected to occur between 1988 and each study year. For all other options, the results indicate the difference between new resource development projected under each option versus that projected for the Existing Contracts options.

The FD and Unrestricted Access cases produce a somewhat different new resource configuration. The most obvious difference from the other cases is that these latter two cases bring on large amounts of coal and, to a lesser degree, hydro, rather than nuclear, to meet future loads. This forecasted pattern of resource development is due to the assumption that WNP-1 and WNP-3 would be completed only if needed to serve BPA's Northwest loads. The FD alternative assumes that BPA would not develop resources to support a firm displacement sale beyond the life of its current surplus. This is also true for all other non-Federal sales receiving assured delivery under the proposed IAP.

Surplus power from the Northwest is currently sold in California under firm contracts and on a "spot market" or "economy sales" basis. The implications of these different forms of purchase are significant. If a utility has a firm contract to purchase specified amounts of power at specified times, this contract can be treated as a dependable generating resource for planning purposes. Otherwise, the purchasing utility needs to provide some sort of backup to spot purchases.

4.4.3 RESOURCE DEVELOPMENT IN CALIFORNIA AND THE INLAND SOUTHWEST

Increased Intertie capacity, given only economy sales, would be expected to have little effect on resource development in California and the Inland Southwest. Appendix H contains additional information on California resource development.

For the Existing Contracts case, future Northwest sales to California were all assumed to be on an economy or spot market basis for surplus above and beyond the existing long-term contracts. If a California utility has a firm contract to purchase specified amounts of power at specified times, the contract can be treated as a dependable generating resource for planning purposes. Alternatively, in most cases, sales on an economy or surplus basis can be relied upon to temporarily displace operating resources only when it is economic to do so. Generally, they cannot be used to defer development of new resources needed to meet firm load. However, if more economy energy could be counted on in most years, California utilities might be able to serve load with a combination of economy energy (when available) and new or refurbished oil and gas plants, to be used when the Pacific Northwest economy energy was not available.

Although the operating costs of these refurbished plants may be quite high, the cost savings resulting from the relatively low cost of economy energy in combination with the deferral of capital investment in baseload plants might exceed the costs incurred by operating the oil and gas plants when economy energy is not available from the Northwest. However, in general, changes in the amount of economy energy purchases affect only the operation of a utility system and have little impact on its planned future resource mix.

The principal generation resource options for meeting California's projected baseload needs in the mid- to late-1990s are either QF resources (such as geothermal power and thermally enhanced oil recovery cogeneration) or out-of-state coal plants (most likely located in the

Inland Southwest). Demand management is another viable alternative to plant additions, but the California utilities have already included substantial amounts of conservation and load management in their resource plans.

The precise mixture of resources that will actually be developed depends on the effects of the avoided-cost pricing and utility rate policies of the California Public Utilities Commission, California Energy Commission siting policies, Federal tax laws, oil and gas prices, environmental regulations, and technological advancements (IPC Report, Appendix C). In the analysis of the effects of changes in Intertie capacity or access provisions for new resources on resource development in California, out-of-state coal plants were used as a proxy for California baseload additions. New Northwest resources would thus displace or defer one or more of those plants.

Several out-of-state coal plants are likely candidates to play the role of generic baseload additions, given their current planning status and overall viability. For southern California, Nevada's 1,500 MW White Pine Power Plant and the 2,000 MW New Mexico Generating Station are both leading candidates (IPC Report, Appendix C). For Northern California, Nevada's 2,000 MW Wells Energy Park and the White Pine Power Plant are reasonable proxies for the out-of-state coal option. Table 4.4.4 summarizes a number of additional out-of-state export or partial-export projects (IPC Report, Appendix C). Any one of the projects mentioned above could provide nearly the entire amount of additional energy expected to be available from the Pacific Northwest with unrestricted firm access for new resources to a fully expanded Intertie.

Table 4.4.4

PROPOSED REGIONAL EXPORT PROJECTS IN THE INLAND SOUTHWEST

Export Projects 1/	Number of Units	Total Capacity (MW)
New Mexico Generating Station	4	2,000
Wells Energy Park	8	2,000
Semi-Export Projects 2/		
Harry Allen	4	2,000
Warner Valley	2	500
White Pine	2	1,500
Inadvertent Export Projects 3/		
Intermountain Power Project 3-4	2	1,500
Springerville 2-3	2	700
Cholla 5	1	350
Coronado 3	1	350
Moon Lake 2	1	390
South Plains Stations	1	500
Plains Escalating Generating Station 1-2	2	420
Nixon 2	(not available)	(not available)

1/ Projects being planned primarily for export.
2/ Projects being planned partially for local load, partially for export.
3/ Projects being planned for local load, but whose output may be exported partially or totally if load growth is slower than planned.

Source: Independent Power Corporation, "Final Report on Intertie Development and Use," January 1986.

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4.5 ECONOMIC ANALYSIS

OVERVIEW AND SUMMARY

The analysis in this section used information, current at the time the Final EIS was being prepared, on loads, resources, and costs of utilities in the Pacific Northwest, California, and British Columbia. The System Analysis Model was used to examine the economic effects of Intertie expansion, formula allocation for access to the Intertie and long-term firm marketing.

In this analysis, the Westwide (Pacific Northwest + California + BC Hydro) net benefit of Interties represents the savings of displacing California resources with economy energy minus Pacific Northwest and BC Hydro production costs and Intertie construction costs.

The analysis shows the DC Terminal Expansion to be cost effective in all cases studied. The Westwide net benefit under base economic assumptions is $996 million (1987 net present value (NPV) dollars). Base economic assumptions include Proposed Formula Allocation, Existing Contracts, medium Pacific Northwest and Caifornia load forecasts, and medium California gas price forecast. The sensitivity analyses show the Westwide net benefit to range from $113 million to $2.6 billion.

The proposed Third AC/COTP (second added to the DC Terminal Expansion) is cost effective in all but two cases. The Westwide net benefit under base economic assumptions is $661 million NPV. The sensitivity analyses show the Westwide net benefit to range from $-388 million to $2.8 billion.

In this analysis, the net benefit of Intertie access policies represents the benefit of using the Intertie under various policies. The Westwide net benefit is derived from the savings of displacing California resources with economy energy minus Pacific Northwest and BC Hydro production costs.

The Westwide net benefit of the Proposed Formula Allocation relative to the Pre-IAP is slightly negative in all cases ranging from $-50 to $-41 million NPV. This is small when compared to the total Westwide benefit of the Existing Interties of $15 billion (less than .5 percent).

The Westwide net benefit of the Hydro-First option relative to the Pre-IAP option is also negative in all cases ranging from $-36 to $-20 million NPV.

In this analysis, the Westwide net benefit of firm contracts represents the net savings of displacing California resources with firm contracts rather than economy energy, plus California resource deferral savings, plus/minus Pacific Northwest purchases, minus Pacific Northwest and BC Hydro production costs.

The Federal Marketing case includes 1,550 MW of firm contracts above the Existing Contracts for the Existing Intertie and DC Terminal Expansion and 2,150 MW for the Maximum Intertie (Terminal Expansion plus Third

AC/COTP). Under the Proposed Formula Allocation, the Westwide net benefit of the Federal Marketing contracts is $557, $590 and $691 million NPV for the Existing Intertie, DC Terminal Expansion and Maximum Intertie, respectively.

The Assured Delivery (400 MW) case includes 1,950 MW of firm contracts above the Existing contracts for the Existing Intertie and DC Terminal Expansion and 2550 MW for the Maximum Intertie. With the additional 400 MW of firm contracts above the Federal Marketing, the Westwide net benefit of the Assured Delivery (400 MW) contracts increases to $651 million for the Existing Intertie, $703 million for the DC Terminal Expansion and $819 million for the Maximum Intertie compared to the Existing contracts.

The Assured Delivery (800 MW) case also includes 1,950 MW of firm contracts above the Existing contracts for the Existing Intertie and DC Terminal Expansion and 2550 MW for the Maximum Intertie, but with a different mix of types of firm contracts than in the 400 MW case. The Westwide net benefit of the Assured Delivery (800 MW) contracts is $985 million for the Existing Intertie, $1,022 million for the DC Terminal Expansion and $1,181 million for the Maximum Intertie compared to the Existing contracts.

This section describes the economic analysis and its findings with respect to increasing Intertie capacity, Formula Allocation and long-term firm contracts. There is also a discussion of the sensitivity analyses conducted as part of the economic analysis. Appendix B, Part 1 contains a description of the models and model assumptions used in the economic analysis.

4.5.1 BACKGROUND

The Pacific Northwest, Canada, California, and the Inland Southwest constitute separate markets and energy resources connected by interregional Interties. These regions have a variety of generating resources, seasonal differences in demand for electric energy, and varying long-term power surpluses and/or deficits. This diversity creates opportunities for more economic use of resources. The Columbia River Treaty and other major interregional agreements--made possible by the large electrical transmission connections between the regions--have enabled each region to reap significant benefits, resulting in lower rates for consumers.

Intertie Capacity

Chapter 1 describes the existing Pacific Northwest-Pacific Southwest Intertie system as well as the proposed capacity expansions. The DC Terminal Expansion is scheduled for completion and energization in early 1989 at an estimated cost of $376 million (1987 NPV). The proposed Third AC/California-Oregon Transmission Project, could be completed and energized in 1991 at an estimated cost of $883 million (1987 NPV).

Formula Allocation

Chapter 1 also describes the development of BPA's Intertie access policies. Chapter 2 discusses the options for Formula Allocation of Intertie access which are examined in the economic analysis. They are: the Pre-IAP option, the Proposed Formula Allocation and the Hydro-First option. The Near Term Intertie Access Policy which is currently in effect and was analyzed in the IDU Draft EIS has been replaced by the currently proposed Long-Term IAP in the analysis for the IDU Final EIS.

Firm Contracts

The economics of firm contracts for the IDU Final EIS were examined for the following four contract cases: Existing Contracts; Federal Marketing; Assured Delivery (400 MW); and Assured Delivery (800 MW).

The Existing Contracts contain existing contracts signed as of December 10, 1986, plus a 225 MW long-term power sale from the Pacific Northwest to California under negotiation at that time.

The Federal Marketing contract case contains 1,550 MW of generic firm contracts in addition to the Existing Contracts. The generic firm contracts include power sales, capacity/energy exchanges, seasonal capacity/energy exchanges, and seasonal power exchanges. An additional 600 MW capacity sale is added upon completion of Third AC/COTP. This amounts to a total of 2,150 MW above the Existing Contracts.

The Assured Delivery (400 MW) contract case includes the Federal Marketing generic firm contracts and an additional Pacific Northwest to California 400 MW generic long-term power sale for a total of 1,950 MW of firm contracts above the Existing Contracts. Upon completion of the Third AC/COTP Intertie in 1991 an additional 600 MW of firm capacity contracts are assumed. The total amount of contracts for the Assured Delivery (400 MW) case with the Third AC/COTP is 2,550 MW above the Existing Contracts.

The Assured Delivery (800 MW) contract case includes the Federal Marketing generic firm contracts less (400 MW), plus 360 MW of long-term power sales and 440 MW of long-term seasonal power exchanges from the Pacific Northwest to California for a total of 1,950 MW of firm contracts above the Existing Contracts. Upon completion of the Third AC/COTP Intertie in 1991 an additional 600 MW of firm capacity contracts are assumed. The total amount of contracts for the Assured Delivery (800 MW) case with the Third AC/COTP is 2,550 MW above the Existing Contracts.

A detailed description of the contract configurations is provided in Appendix B, Part 4.

4.5.2 ANALYSIS

Studies were done using the System Analysis Model (SAM) to evaluate the economic impacts of Intertie expansions, formula allocation, and firm contracts. The net present value of changes in costs and benefits for the Intertie expansions was calculated through the year 2030. The net present value of net benefits for the formula allocation and firm contracts options was calculated through the year 2006. The SAM study horizon is 20 years from 1987 through 2006. For years beyond the study horizon (2007-2030), the twentieth year's values are extended, assuming a 5-percent inflation rate and 0-percent escalation rate.

Effects of Increasing Intertie Capacity

In addition to increased sales of economy energy, an expanded Intertie also provides benefits as a result of the additional ability to shape sales into California's daytime hours (see Figure 4.5.1). This energy is more valuable to California and commands a higher price for the Pacific Northwest. Figure 4.5.2 shows the California marginal cost for each 1,000 MW block for each Intertie case. The marginal costs remain higher for larger Intertie sizes after the 3,000 MW block. This reflects the Pacific Northwest's ability to shape more sales into onpeak hours.

Table 4.5.1 shows the net incremental benefit for each Intertie expansion level. The Westwide net benefit represents the value of displacing California resources with economy energy, minus Intertie construction costs and Pacific Northwest and BC Hydro production costs. The Third AC/COTP alternative for the Federal Marketing and Assured Delivery contract cases includes California resource deferral and displacement benefits associated with the 600 MW of firm capacity sales. These results do not represent expected values over all sensitivity variables but are based on a single set of assumptions described later in this section.

Table 4.5.1

INCREMENTAL NPV OF INTERTIE EXPANSIONS TO YEAR 2030
(1987 $ Millions)

Formula Allocation/Contracts	Incremental Westwide Net Benefit 1/
Proposed/Existing	
DC Upgrade - Existing	996
Maximum - DC Upgrade	661
Proposed/Federal Marketing	
DC Upgrade - Existing	954
Maximum - DC Upgrade	880

Table 4.5.1 (Continued)

Formula Allocation/Contracts	Incremental Westwide Net Benefit 1/
Proposed/Assured Delivery (400 MW)	
DC Upgrade - Existing	1026
Third AC - Existing	1628
Maximum - DC Upgrade	950
Proposed/Assured Delivery (800 MW)	
DC Upgrade - Existing	1087
Maximum - DC Upgrade	990
Hydro-First/Federal Marketing	
Maximum - Existing	1802
Hydro-First/Assured Delivery (400 MW)	
Maximum - Existing	1935
Pre-IAP/Federal Marketing	
Maximum - Existing	1844
Pre-IAP/Assured Delivery (400 MW)	
Maximum - Existing	1998

1/ Net benefits are not additive across the contracts or Formula Allocation cases. Differences between incremental numbers are not meaningful since the two base cases are not the same.

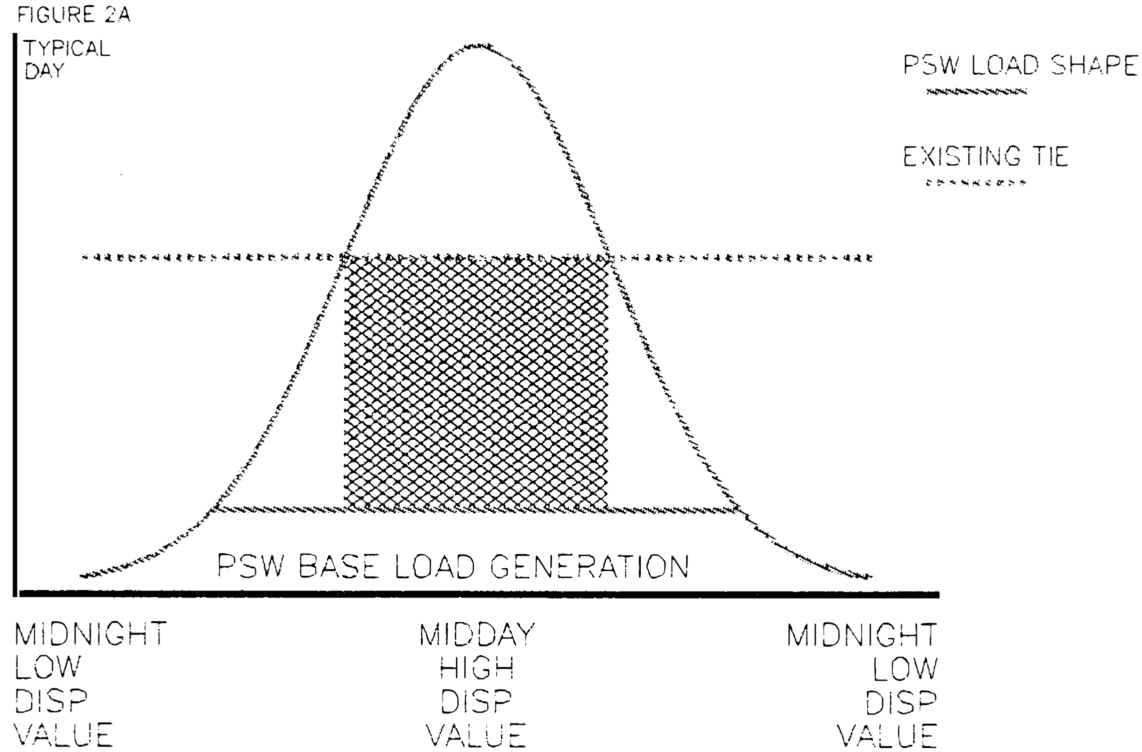
The Westwide net benefit of the DC Upgrade under the Proposed Formula Allocation ranges from $954 to $1,087 million NPV depending on contract assumptions.

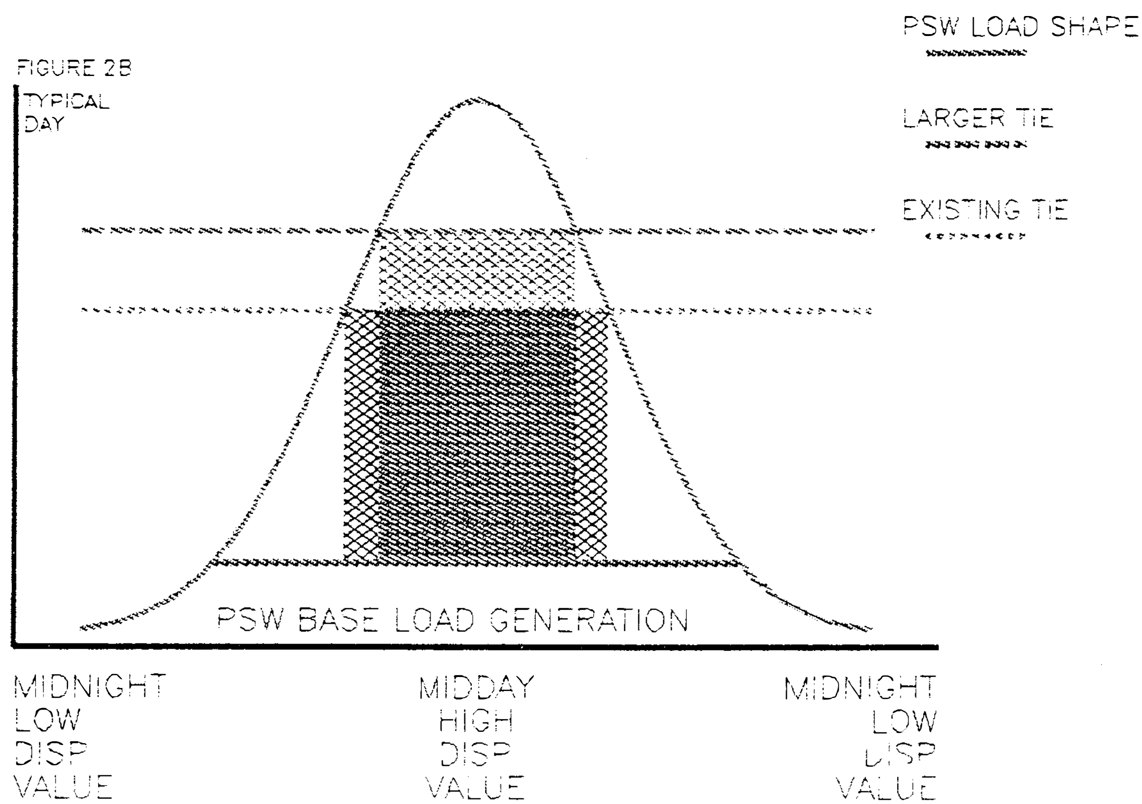
Although it is unlikely the Third AC/COTP would be built without the DC Upgrade, the Westwide net benefit of the Third AC/COTP first added with the Proposed Formula Allocation and Assured Delivery (400 MW) contracts is $1,628 million NPV.

The Westwide net benefit of the Third AC/COTP second added, under the Proposed Formula Allocation ranges from $661 to $990 million NPV, depending on contract assumptions.

The Westwide net benefit of the DC Upgrade plus Third AC/COTP under the Proposed Formula Allocation compared to the Existing Interties ranges from $1,657 to $2,077 million NPV, depending on contract assumptions. Under the Pre-IAP, the Westwide net benefit is $1,844 and $1,998 million for the Federal Marketing and Assured Delivery (400 MW) contracts cases. For the Hydro-First option, the net benefit is $1,802 and $1,935 million, respectively.

FIGURE 4.5.1 IMPACT ON DISPLACEMENT VALUE OF INCREASING INTERTIE CAPACITY





SYSTEM CAPABILITIES AND MARKETING ANALYSIS BRANCH - PRC

FIGURE 4.5.2.

CALIFORNIA MARGINAL COST
EXISTING CONTRACTS : AUGUST 1992

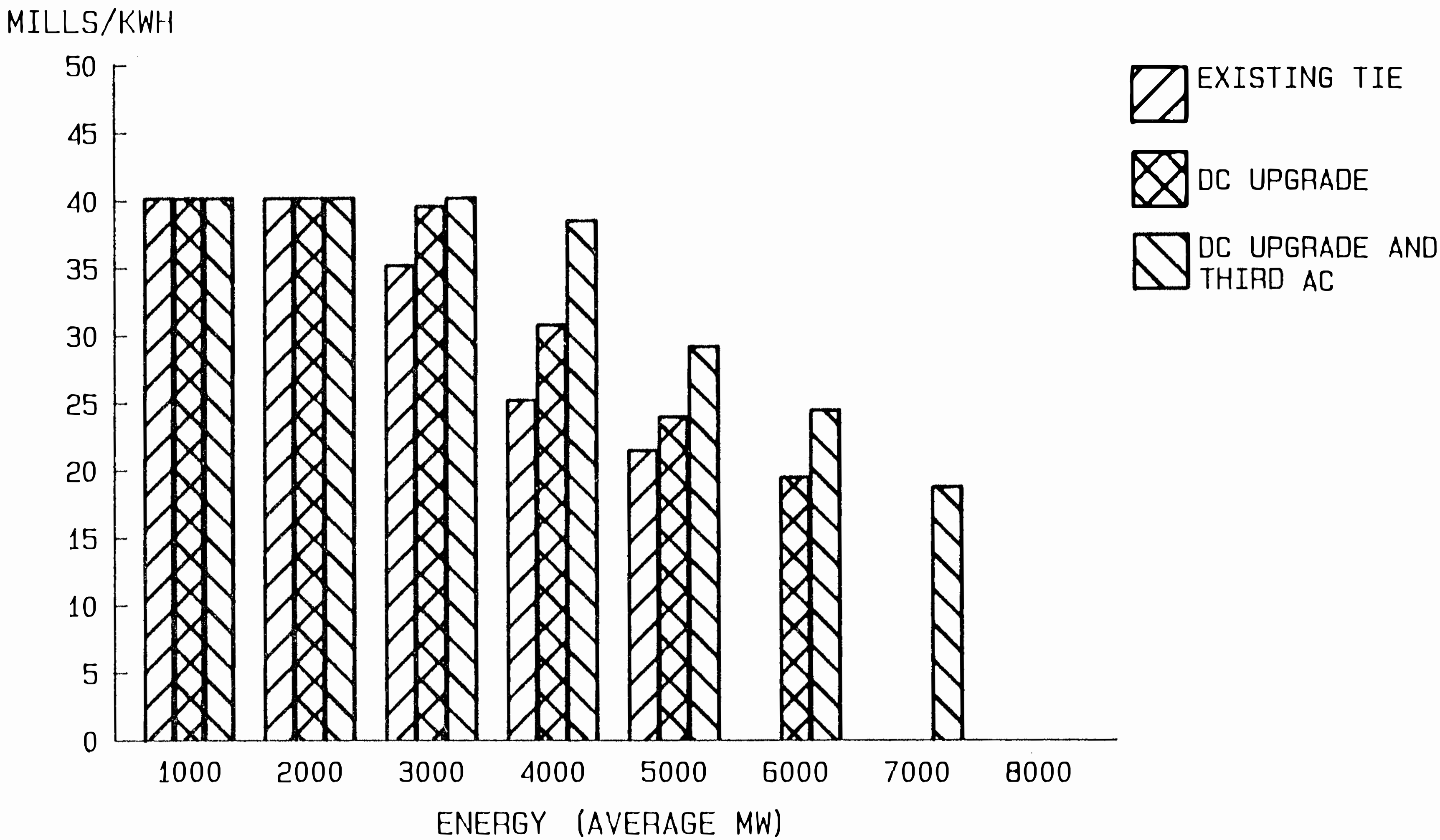


Figure 4.5.3 illustrates the secondary MW (Pacific Northwest + BC Hydro) sold on the Existing, DC Upgrade and Third AC/COTP Interties given the Proposed Formula Allocation and Existing Contracts. An annual average of approximately 280 additional MW are sold with the increased capacity provided by the DC Upgrade and 270 MW with the Third AC/COTP second added.

Payback/Point of Investment Recovery

Table 4.5.2 shows the Payback Date/Point of Investment Recovery for the DC Upgrade and Third AC/COTP, under the Proposed Formula Allocation, given various contract assumptions. The payback date represents the point in time that the Intertie construction costs are recovered by benefits from the Intertie. Figure 4.5.4 illustrates Table 4.5.2 graphically for the Existing Contracts. The payback period for the Third AC/COTP is longer than the DC Upgrade. This reflects the higher construction costs of the Third AC/COTP relative to the additional sales enabled by the facility over and above the DC Upgrade.

Table 4.5.2

INTERTIE EXPANSIONS
PAYBACK DATE/POINT OF INVESTMENT RECOVERY

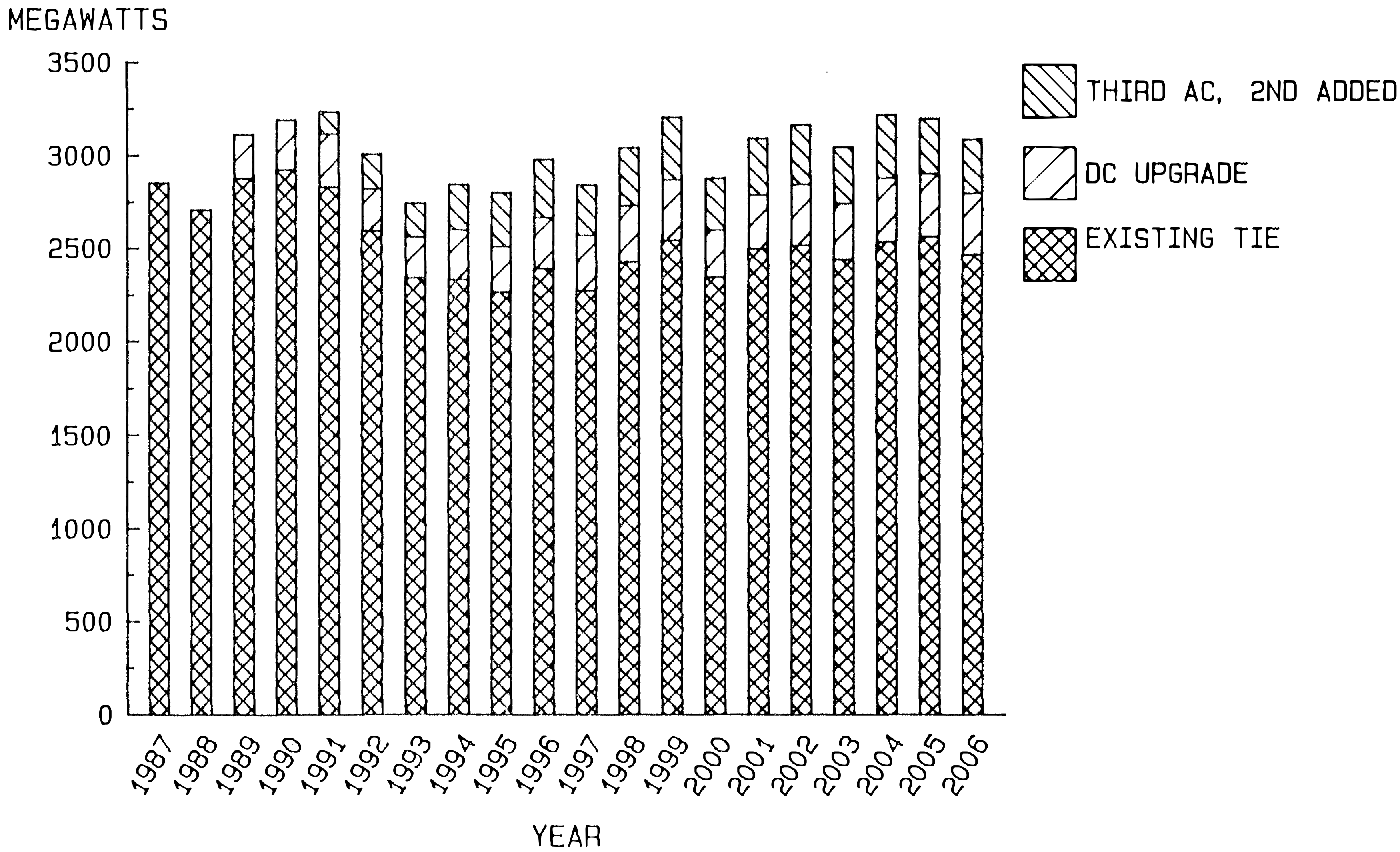
Contract Case	Payback Date	Recovery Period (years)
--- DC Upgrade		
Existing Contracts	1999	10
Federal Marketing	1999	10
Assured Delivery (400 MW)	1998	9
Assured Delivery (800 MW)	1998	9
--- Third AC/COTP 2nd Added		
Existing Contracts	2009	18
Federal Marketing	2009	18
Assured Delivery (400 MW)	2007	16
Assured Delivery (800 MW)	2006	15

Effects of Formula Allocation Options

Table 4.5.3 shows the difference between Westwide net benefits of Intertie sales under the Pre-IAP versus the Proposed and Hydro-First formula allocation options under different contract and Intertie assumptions. There is a small cost associated with the Proposed Formula Allocation and Hydro-First options when compared incrementally with the Pre-IAP. This is due to a small increase in Pacific Northwest production costs.

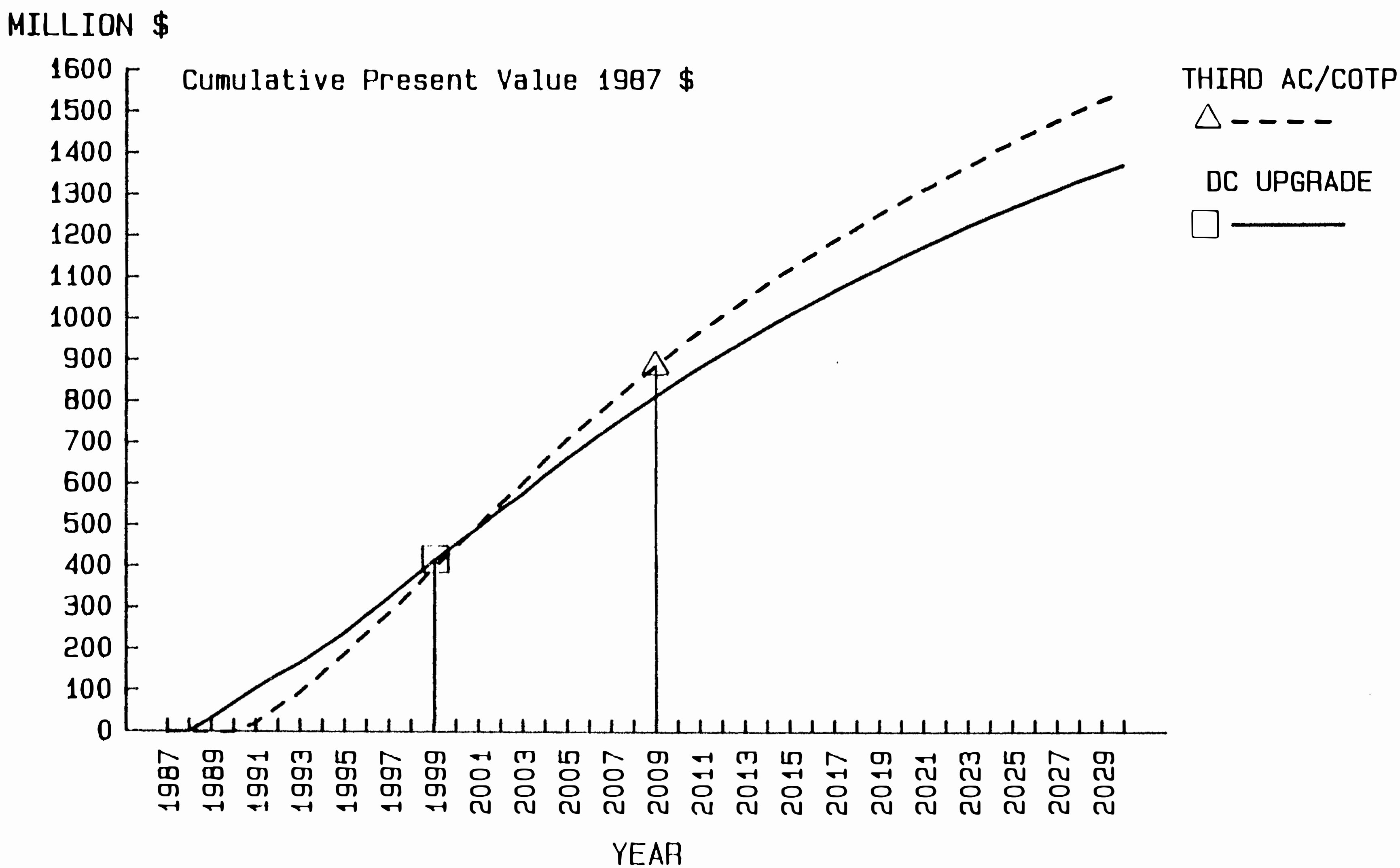
Under the Proposed Formula Allocation the Westide net benefit ranges from $-50 to $-41 million over 20 years. For the Hydro-First option the Westide net benefit ranges from $-36 to $-20 million. The different contract cases and Intertie capacity levels (Existing and Maximum) affect the net benefit marginally. The negative net benefit is small relative to the total benefit of the Interties of $15 to $17 billion.

FIGURE 4.5.3.
SECONDARY MEGAWATTS
PROPOSED IAP : EXISTING CONTRACTS



4.5-9

FIGURE 4.5.4.
POINT OF INVESTMENT RECOVERY
EXISTING CONTRACTS



Note: Without transmission costs.

Table 4.5.3

EFFECTS OF FORMULA ALLOCATION ON
INCREMENTAL NPV TO YEAR 2006
(1987 $ Millions)

Contract Case	Intertie Capacity	Westwide Net Benefit
--- Benefit of Proposed Formula Allocation - Pre-IAP		
Existing Contracts	Existing	-48
Federal Marketing	Existing	-49
Federal Marketing	Maximum	-41
Assured Delivery (400 MW)	Existing	-50
Assured Delivery (400 MW)	Maximum	-46
Assured Delivery (800 MW)	Existing	-50
Assured Delivery (800 MW)	Maximum	-43
--- Benefit of Hydro-First - Pre-IAP		
Existing Contracts	Existing	-27
Federal Marketing	Existing	-30
Federal Marketing	Maximum	-28
Assured Delivery (400 MW)	Existing	-23
Assured Delivery (400 MW)	Maximum	-36
Assured Delivery (800 MW)	Existing	-20
Assured Delivery (800 MW)	Maximum	-36

Effects of Long-Term Contracts

Table 4.5.4 shows the Westwide net benefit of the Federal Marketing and Assured Delivery contracts measured incremental to the Existing Contracts.

The Westwide net benefit of the Federal Marketing contracts is $557 million for the Existing Intertie, $590 million for the DC Upgrade and $691 million for the Maximum Intertie. The Westwide net benefit of the Assured Delivery (400 MW) contracts is $651 million for the Existing Intertie, $703 million for the DC Upgrade and $819 million for the Maximum Intertie.

Table 4.5.5 shows the Pacific Northwest purchases, California resource deferral benefits, and incremental MW for the firm contracts. For the Federal Marketing contracts, the Pacific Northwest avoided purchases of $22 million as a result of the exchange provisions in the contracts that convert from power sales to capacity/energy exchanges at load/resource balance.

TABLE 4.5.4

EFFECTS OF FIRM CONTRACTS ON INCREMENTAL NPV TO YEAR 2006 (1987 $ Millions)

Contract Case	Intertie Capacity	Westwide Net Benefit 1/
Federal Marketing	Existing	557
Federal Marketing	DC Upgrade	590
Federal Marketing	Maximum	691
Assured Delivery (400 MW)	Existing	651
Assured Delivery (400 MW)	DC Upgrade	703
Assured Delivery (400 MW)	Maximum	819
Assured Delivery (800 MW)	Existing	985
Assured Delivery (800 MW)	DC Upgrade	1022
Assured Delivery (800 MW)	Maximum	1181
Assured Delivery Alt. #3 (800 MW)	Maximum	1465

1/ The net benefit is the Westwide net benefit of the Intertie, assuming the indicated firm marketing condition and the Proposed formula allocation, minus the net benefit of the Intertie assuming the Existing Contracts and Proposed Formula Allocation options.

Table 4.5.5

FIRM CONTRACTS CAPITAL SAVINGS/COSTS 1/

Contract Case	Intertie Capacity	Contract Demand (MW)	CA Resource Deferral (Million $) 2/	PNW Purchases (Million $) 3/
Federal Marketing	Existing	1550	103	-22
Federal Marketing	Maximum	2150	135	-22
Assured Delivery (400 MW)	Existing	1950	124	37
Assured Delivery (400 MW)	Maximum	2550	156	37
Assured Delivery (800 MW)	Existing	1950	124	167
Assured Delivery (800 MW)	Maximum	2550	156	167

1/ The net benefit is the capital saving/cost of the Intertie, assuming the indicated firm marketing condition and the Proposed formula allocation, minus the net benefit of the Intertie assuming the Existing Contracts and Proposed Formula Allocation options.

2/ Deferral of Combustion Turbines at $494 kW

3/ Purchases at 14.7 mills/kWh

4.5.3 SENSITIVITY AND OTHER ANALYSIS

All sensitivity analyses performed in conjunction with the economic analysis assume the Proposed Formula Allocation and Existing Contracts.

The sensitivity variables considered for the Intertie economic analyses include:

California Gas Prices. BPA's September 1987 low and high long-term gas price forecasts were assumed. Low gas prices range from 14 to 22 mills/kWh over the study horizon. High gas prices range from 30 to 65 mills/kWh.

California Loads. It was assumed that California loads vary plus (high) and minus (low) 2,000 MW from the medium Common Forecasting Methodology (CFM-VI) forecast. The CFM-VI California loads range from approximately 24,000 to 35,000 average MW over the study horizon.

California Marginal Cost. It was assumed California pays a maximum of 50 percent (instead of 75 percent) of the marginal cost of the resource displaced by Pacific Northwest nonfirm energy.

Pacific Northwest Loads. BPA's July 1986 low and high load forecasts were assumed. Over the study horizon, the medium loads range from 18,000 to 22,000 average MW, the low loads range from 18,000 to 16,000 average MW and the high loads from 19,000 to 30,000 average MW.

Firming Nonfirm Strategies. It was assumed that the Pacific Northwest would install 800 and 1600 MW of combustion turbines which would run only if there is insufficient nonfirm energy. The combustion turbines would replace WNP-1 and WNP-3.

Environmental Dispatch. An environmental dispatch of coal resources (Colstrip, Valmy, Boardman, Bridger, Corette, Centralia), rather than an economic dispatch (Colstrip, Corette, Bridger, Centralia, Valmy, Boardman) was assumed.

Canadian Firm Sale. A firm power sale of 500 average MW from BC Hydro to California starting in 1991 was assumed.

BC Hydro Price Decrease. The price of BC Hydro spill was assumed to be 10 mills instead of 14 mills/kWh.

Third AC/COTP Transmission Cost Increase. The net present value of the transmission cost was assumed to increase by 10 percent.

The results of the sensitivity analyses are presented in Table 4.5.6. Varying Pacific Northwest loads has the most impact on the Westwide net benefit of Intertie expansions. High Pacific Northwest loads reduce the net benefit of the DC Upgrade to $170 million and the Third AC/COTP (second added) to $-98 million (NPV). Low Pacific Northwest loads increase the net benefit substantially to $2.6 billion for the DC Upgrade and $2.8 billion for the Third AC/COTP. Assuming that the probabilities of low, medium, and high Pacific Northwest loads occurring are .25, .50, and .25, the expected net benefit is $1,194 million for the DC Upgrade and $998 million for the Third AC/COTP. These results are greater than the net benefit under medium loads.

Varying California gas prices also has a significant impact on the Westwide net benefit of Intertie expansions. High California gas prices substantially increase the Westwide net benefit of the DC Upgrade to $2.0 billion and Third AC/COTP (second added) to $2.0 billion. Low California gas prices reduce the net benefit of the DC Upgrade to $113 million and the Third AC/COTP to $-338 million. Assuming that the probabilities of low, medium, and high gas prices occurring are .25, .50, and .25, the expected net benefit is $1,030 million for the DC Upgrade and $724 million for the Third AC/COTP. These results are greater than the net benefit under medium gas prices.

Table 4.5.6

EFFECTS OF SENSITIVITY ANALYSIS ON
INCREMENTAL NPV TO YEAR 2030
(1987 Million $)

Westwide Net Benefit 1/

Sensitivity	DC Upgrade-Existing	Maximum-DC Upgrade	Maximum-Existing
Base	996	661	1657
CA Low Gas	113	-388	-274
CA High Gas	2013	1963	3975
CA Low Load (-2000 MW)	887	485	1373
CA High Load (+2000 MW)	1168	709	1878
50% Marginal Cost	822	440	1262
PNW Low Load	2614	2766	5380
PNW High Load	170	-98	73
Firm Nonfirm 800 MW	706	354	1060
Firm Nonfirm 1600 MW	519	180	699
Environmental Dispatch	793	251	1044
Canadian Firm Sale	1188	1080	2268
BC Hydro Price Decrease	998	666	1661
Third AC/COTP Trans. Cost	-	573	1569

1/ Assumes Proposed Formula Allocation and Existing Contracts.

Low California loads (-2,000 MW) reduce the Westwide net benefit of the Maximum Intertie from $1,657 to $1,373 million while high California loads (+2,000 MW) increase the net benefit to $1,878 million.

Assuming California is willing to pay 50 percent of their marginal cost (decremental cost), the Westwide net benefit of the Maximum Intertie is reduced to $1,262 million. This occurs because the Pacific Northwest has fewer saleable resources.

If the Pacific Northwest chooses to adopt a firming nonfirm strategy, the Westwide net benefit of the Maximum Intertie is reduced from $1,657 to $1,060 million for 800 MW and to $699 million for 1600 MW. Since combustion turbines replace base loaded resources and are the most expensive to operate, the Pacific Northwest would use 800 MW or 1,600 MW of nonfirm to displace combustion turbines instead of selling it to California.

An environmental (rather than economic) dispatch of coal plants reduces the Westwide net benefit of the Maximum Intertie to $1,044 million. This occurs because Valmy and Boardman are too expensive to run for California sales in early years. Therefore, Bridger, Corette and Centralia are not dispatched to sell to California.

Allowing BC Hydro to make a firm power sale of 500 average MW increases the Westwide net benefit of the Maximum Intertie from $1,607 to $2,268 million. The firm sale effectively reduces the availability of the Existing Intertie for economy energy sales by 500 average MW. Therefore, the value of increasing Intertie capacity is greater with the firm sale.

Decreasing BC Hydro's spill price from 14 to 10 mills/kWh has little impact on Westwide net benefits. When BC Hydro has surplus and Intertie access under Condition 3, demand is usually greater than the supply and market prices are typically higher. Therefore, a 4 mill decrease in BC Hydro price makes little difference in the amount of MW sold.

The Plan-of-Service for the Third AC/COTP transmission additions has not been finalized. If the net present value of the transmission costs increased by 10 percent over the current estimates, the Westwide net benefit will be reduced by $88 million.

Additional information on these sensitivity analyses is contained in Appendix B, Part 6.

4.5.4 ASSUMPTIONS

<u>Present Value</u>

All costs and benefits are expressed as net present values in 1987 dollars, using a nominal discount rate of 8.15 percent (a 5 percent inflation rate and a 3 percent real discount rate).

The SAM study horizon is 20 years from 1987 through 2006. For years beyond the study horizon, the twentieth year's values are extended assuming a 5 percent inflation rate and a 0 percent escalation rate.

The modeling of Intertie Access Policies, the California market, transmission losses and loopflow, are included in Appendix B, Part 2. Transmission costs, load and resource data are also included.

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4.6 CONSULTATION, REVIEW, AND PERMIT REQUIREMENTS

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

1. Environmental Policy: The Intertie actions have the potential for adversely impacting local air quality near PNW coal plants and improving air quality in California and the ISW. They may have minor adverse impacts on fish in the Columbia and Snake river systems. BPA has worked closely with the U.S. Army Corps of Engineers and the U.S. Bureau of Reclamation in evaluating these effects.

2. Endangered and Threatened Species and Critical Habitat: Informal consultation on endangered and threatened species has been initiated with the U.S. Fish and Wildlife Service. BPA has determined that the project is not likely to adversely affect any threatened and endangered species. The U.S. Fish and Wildlife Service's concurrance to BPA's biological assessment will be included in the ROD.

3. Fish and Wildlife Conservation: The Intertie decisions could, in some cases, alter the timing of PNW river flows as well as the amounts of spill occurring at hydroelectric projects in the region. These changes could create minor adverse impacts to fish. BPA has worked closely with the U.S. Army Corps of Engineers and the Columbia River Intertribal Fish Commission in evaluating the potential for impact.

4. Operating changes at hydroelectric projects would potentially have effects on cultural resources in and around Federal storage reservoirs in the PNW. These reservoirs are: Grande Coulee (Lake Roosevelt), Dworshak, Libby (Lake Koocanusa), Albeni Falls (Lake Pend Oreille), and Hungry Horse. Many cultural resource sites in the areas of potential effect have already been and continue to be affected by erosion and vandalism, and in other ways. Changes in reservoir elevations may change the rate of site erosion and may make sites more or less accessible to vandals.

   Known properties on or eligible for the National Register of Historic Places that may be affected by the IDU actions are the Middle Kootenai River Archaeological District at Lake Koocanusa, Montana, and the Kettle Falls Archaeological District and the Fort Spokane Historic District at Lake Roosevelt, Washington. Information about the existence and significance of cultural resources within the area of potential effect is incomplete and it is very possible that other potentially affected properties may be eligible for the National Register.

BPA has initiated procedures to develop a Programmatic Agreement with the Advisory Council on Historic Preservation, the Idaho, Montana, and Washington State Historic Preservation Officers, the Bureau of Reclamation, and the Corps of Engineers. Execution of the Agreement will satisfy BPA's responsibilities under section 106 of the National Historic Preservation Act (16 U.S.C. 470, et seq.) for all individual IDU undertakings. Terms of the Agreement may include provisions for further identification and evaluation of potentially affected resources, and mitigation of a share of the continuing impacts in proportion to the incremental increase of impact caused by IDU actions.

Also to be involved in developing the Programmatic Agreement will be: the Confederated Tribes of the Colville Reservation, Washington; the Spokane Tribe of the Spokane Reservation, Washington; the Kalispel Indian Community of the Kalispel Reservation, Washington; the Coeur D'Alene Tribe of the Coeur D'Alene Reservation, Idaho; the Nez Perce Tribe of Idaho, Nez Perce Reservation, Idaho; the Kootenai Tribe of Idaho; the Confederated Salish and Kootenai Tribes of the Flathead Reservation, Montana; the Blackfeet Tribe of the Blackfeet Indian Reservation of Montana; the Bureau of Indian Affairs; the U.S. Forest Service; and the National Park Service.

The Programmatic Agreement will also be designed to ensure consistency with the American Indian Religious Freedom Act (42 U.S.C. 1996), by providing for BPA participation in the relocation of Native American burials when such sites are discovered through the resource survey and evaluation that will occur as part of the Agreement.

Other hydroelectric project reservoirs in the Federal Columbia River Power System are operated either as run-of-river or primarily for flood control and are generally independent of power marketing activities. IDU actions would, therefore, not affect cultural resources at hydroelectric projects other than the five listed above.

5. State, Areawide, and Local Plan and Program Consistency: The Third AC/COTP could result in the acquisition and changed use of real property. These impacts will be addressed in detail in the California/Oregon Transmission Project Environmental Impact Statement. BPA is acting as a cooperating agency in the preparation of that EIS.

6. Coastal Zone Management Program Consistency: The Intertie actions will have no impact on coastal zone management.

7. Floodplains: The Intertie actions will have no effect on floodplains.

8. Wetland: The Intertie actions will have no effect on wetlands.

9. Farmlands: The Third AC/COTP could result in the construction of transmission towers in agricultural areas. This potential will be considered in detail in the California/Oregon Transmission Project Environmental Impact Statement (COTP EIS). BPA is a cooperating agency in the preparation of the COTP EIS.

10. Fecreation Resources: The Intertie actions are not expected to significantly impact the use of outdoor public recreation facilities.

11. Permit for Structures in Navigable Waters: The Third AC/COTP may result in construction of a transmission facility over the Sacramento River. The effects of such construction will be addressed in the COTP EIS.

12. Permit for Discharges into Waters of the United States: The Intertie actions will not result in discharge of dredged or fill material into waters of the United States.

13. Permit for Right-of-Way on Public Land: The Third AC/COTP could affect the use of public lands. These effects will be addressed in the COTP EIS.

14. Pollution Control at Federal Facilities: The Intertie actions would not result in procurement of goods, services, or materials from a facility on the EPA's List of Violating Facilities; violation of clean air, water quality, drinking water, solid waste disposal or noise standards; or production or transportation of hazardous waste. Addition of the Third AC/COTP to the Intertie system could result in the purchase and use of pesticides. The latter will be discussed in the COTP EIS. The Intertie decisions are not expected to alter the use of materials containing PCB's.

15. Energy Conservation at Federal Facilities: The Intertie actions would not affect energy conservation at Federal Facilities.

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PROPOSED LONG-TERM INTERTIE ACCESS POLICY

Chapter 5

PROPOSED LONG-TERM INTERTIE ACCESS POLICY

INTRODUCTION

The Bonneville Power Administration first implemented an Interim Intertie Access Policy in September 1984. Following preparation of an Environmental Assessment and Finding of No Significant Impact, the Near-Term Intertie Access Policy was placed in effect on June 1, 1985. The Administrator is proposing to replace the Near-Term IAP with the Proposed Long-Term Intertie Access Policy. Several drafts of the Long-Term Intertie Access Policy have been circulated for public review and comment. The most recent of these was distributed on December 15, 1987.

Since distribution of the December 15, 1987, Revised Draft Long-Term Intertie Access Policy, BPA has received numerous comments on the proposed provisions. As a result of BPA's evaluation of these comments, modifications to the Revised Draft Policy are being incorporated in the current policy proposal as follows:

Section 5(c)(1)(B)(i) shall read:

> Each hour, the maximum Condition 1 allocations for BPA and each Scheduling Utility will be based on the ratio of their respective declarations to total declarations, multiplied by the available Intertie capacity. Available Intertie capacity is defined as the physically available capacity, reduced by the amount of capacity reserved to satisfy the Administrator's power marketing program, existing transmission contracts listed in Exhibit C, and Assured Delivery contracts not subject to mitigation requirements of section 4(4). Examples of allocations under Condition 1 are shown in Exhibit A.

Section 5(c)(1)(B)(ii) shall read:

> During Condition 1, whenever BPA is unable to sell its full pro rata allocation, BPA will take larger allocations on ensuing Condition 1 days until the difference is eliminated.

Section 5(c)(1)(B)(iii) shall read:

> BPA will reduce each Scheduling Utility's allocation by any Protected Area decrements determined pursuant to section 7.

The intent of these changes is to eliminate the "Hydro Cap" and "allocation to market" concepts originally contained in the December 15, 1987, Revised Draft IAP. All other aspects of the Revised Draft Policy, including the exhibits to the policy, should be assumed to be consistent with these changes. The Administrator may make further modifications to this proposal as judged appropriate based on this EIS and other portions of the administrative record, prior to issuing a final policy.

The December 15, 1987, Revised Draft Long-Term Intertie Access Policy follows.

REVISED DRAFT

LONG-TERM INTERTIE ACCESS POLICY

Governing Transactions over Federally Owned
Portions of the
Pacific Northwest-Pacific Southwest Intertie

U.S. Department of Energy
Bonneville Power Administration
December 15, 1987

Table of Contents

REVISED DRAFT LONG-TERM INTERTIE ACCESS POLICY

Section 1. Definitions

1. "Administrator" means the Administrator of Bonneville Power Administration (BPA) and is used interchangeably with BPA.

2. "Administrator's Power Marketing Program" refers to all marketing actions taken and policies developed to fulfill BPA's statutory obligations. These actions and policies are based on exercises of broad authority to act, consistent with sound business principles, to recover revenue adequate to amortize Federal investments in the Federal Columbia River power and transmission systems, while encouraging diversified use of electric power at the lowest practical rates. In the Northwest, the Administrator's Power Marketing Program includes BPA's power supply obligations and programs to market surplus power in a manner that assures an adequate, reliable, economical, efficient, and environmentally acceptable power supply, while preserving regional and public preference to Federal electric power. In the Southwest, the Administrator's Power Marketing Program includes the Administrator's programs to market surplus Federal power at equitable prices and to assist in marketing the Northwest's non-Federal power surplus.

3. "Assured Delivery" means firm Intertie transmission service provided by BPA under a transmission contract to wheel power covered by a contract between a Scheduling Utility and a Southwest utility. Assured Delivery contracts may not exceed 20 years' duration. The service is interruptible only in the event of an uncontrollable force or a determination made pursuant to sections 7 or 8 of this policy. Assured Delivery service will be reduced only by the amount of transmission capacity to the Southwest later acquired by a Scheduling Utility through ownership or contract.

4. "BPA Resources" means Federal Columbia River Power System hydroelectric projects; resources acquired by BPA under long-term contracts, including resources acquired pursuant to sections 5(c) and 6 of the Northwest Power Act; and resources acquired pursuant to section 11(b)(6)(i) of the Federal Columbia River Transmission System Act.

5. "Extraregional Utilities" are generating utilities, or divisions thereof, that do not provide retail electric service and own or operate significant amounts of generating capacity in the Northwest.

6. "FD Supported Sale" means that portion of a Scheduling Utility's firm sale equal, in amount and shape, to the utility's purchase of BPA Firm Displacement power.

7. "Formula Allocation" means the shares of Intertie Capacity made available to Scheduling Utilities and, under certain conditions, Extraregional Utilities for short-term sales of energy.

8. "Intertie" means the two 500-kilovolt (kV) alternating current (AC) transmission lines and one 1,000-kV direct current (DC) line, which extend from Oregon into California or Nevada, and any additions thereto identified by BPA as Pacific Northwest-Pacific Southwest Intertie facilities.

9. "Intertie Capacity" means the North to South transmission capacity of the Intertie controlled by BPA through ownership or contract; increased by power scheduled South to North, decreased by loop flow, outages, and other factors that reduce transmission capacity; and further decreased by Pacific Power & Light Company's schedules, under its scheduling rights at the Malin substation (BPA Contract Nos. DE-MS79-86BP92299 and DE-MS79-79BP90091).

10. "Mitigation" refers to the conditions, other than rate schedule provisions, imposed by BPA on a Scheduling Utility in return for an Assured Delivery contract. Mitigation helps offset operational and economic problems, attributable to a Scheduling Utility's power transaction, that inhibit BPA's ability to meet its existing firm load obligations or to generate revenues. The Mitigation measures specified in this policy must be included in all Assured Delivery contracts, unless substitute measures are negotiated with BPA on a case-by-case basis.

11. "Nonscheduling Utility" means a non-Federal Northwest utility that owns a generating resource, but does not operate a generation control area within the Pacific Northwest. A Nonscheduling Utility requesting Intertie access for its resource must do so through the Scheduling Utility (or BPA) in whose control area the resource is located.

12. "Pacific Northwest" (or "Northwest") is defined in the Northwest Power Act, 16 U.S.C. §839e, as the states of Oregon, Washington, and Idaho; the portion of Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming within the Columbia River drainage basin; and any contiguous service territories of rural electric cooperatives serving inside and outside the Pacific Northwest, not more than 75 air miles from the areas referred to above, that were served by BPA as of December 1, 1980.

13. "Protected Area" means a stream reach within the Columbia River drainage basin specially protected from hydroelectric development because of the presence of anadromous or high value resident fish, or wildlife. Protected areas may also include stream reaches which could support anadromous fish if investments were made in habitat, hatcheries, passage, or other projects. This policy contemplates that BPA will implement,

after review and possible modification, a comprehensive protected area program adopted by the Pacific Northwest Electric Power and Conservation Planning Council.

14. "Qualified Extraregional Resources" means:

(a) a generating unit located outside the Northwest that was in commercial operation on the effective date of this policy. However, the term excludes the portions of units covered as Qualified Northwest Resources.

(b) after the Administrator has determined that the capacity of the Intertie is rated at approximately 7,900 MW, all resources located outside of the Northwest, other than the portions of extraregional resources covered as Qualified Northwest Resources.

15. "Qualified Northwest Resources" exclude BPA Resources, but include:

(a) Generating resources located inside the Northwest that were in commercial operation on the effective date of this policy. Regarding generating resources owned or controlled by Nonscheduling Utilities, it must be demonstrated that a relationship had been established by that date with a Scheduling Utility or BPA to serve Northwest loads.

(b) Scheduling Utility extraregional generating resources dedicated to Northwest loads on the effective date of this policy. This term includes pro rata portions of Montana Power Company's and Pacific Power and Light Company's shares of the Colstrip No. 4 generating station, based on the ratio of their respective regional loads to their respective total loads; and Idaho Power Company's share of Valmy No. 2.

(c) New regional resources of Scheduling Utilities, except for hydroelectric resources located in Protected Areas, needed to support power contracts receiving Assured Delivery service under this policy.

16. "Resource" means an identified electric generating unit or stack of particular electric generating units identified to supply power or capacity for sale over the Intertie.

17. "Scheduling Utility" means the Northwest portion of a non-Federal utility that operates a generation control area within the Northwest.

18. "Seasonal Exchange" means a transaction that takes advantage of seasonal diversity between Northwest and Southwest loads through transfers of firm power, at a prespecified delivery rate, from North to South during the Southwest's summer load season and from South to North during the Northwest's winter load season. Seasonal Exchanges may

involve payments of additional consideration to reflect the relative seasonal values of power throughout the western United States. Seasonal Exchange schedules of Northwest utilities will be referred to as "deliveries," and schedules of Southwest utilities will be referenced as "returns." A Scheduling Utility must be able to support its summertime firm power deliveries with generating resources that are surplus to its Northwest requirements. The sum of a Scheduling Utility's energy resources for each month in which deliveries are made (with special concern for August) must exceed its corresponding Northwest loads by an amount sufficient to support the Seasonal Exchange.

19. "Section 9(i)(3) resource" means a Scheduling Utility resource that BPA has granted priority in receiving BPA transmission, storage and load factoring services.

Section 2. <u>Intertie Capacity Reserved for BPA</u>

The Administrator reserves for BPA's use Intertie Capacity sufficient to:

(a) deliver the full amount of BPA's surplus firm power,

(b) perform obligations under existing BPA transmission contracts listed in Exhibit C, to the extent such obligations differ from the conditions specified in this policy, and

(c) provide Assured Delivery service for transactions not subject to limits under Exhibit B to this policy.

Section 3. <u>Conditions For Intertie Access</u>

(a) All Intertie access will be granted pursuant to the conditions and procedures of this policy, unless otherwise specified in the three existing BPA transmission contracts listed in Exhibit C.

(b) BPA will provide Intertie access only for BPA Resources and the Qualified Northwest Resources of Scheduling Utilities, except to the extent that Qualified Extraregional Resources are permitted access under this policy.

(c) BPA will provide Assured Delivery and allocate remaining Intertie Capacity when providing such access will not substantially interfere with operating limitations of the Federal system. Examples of these limitations, which reflect BPA's obligation to operate in an economical and reliable manner consistent with prudent utility practices, include:

(1) The BPA reliability criteria and standards,

(2) Western Systems Coordinating Council minimum operating reliability criteria,
(3) North American Electric Reliability Council Operating Committee minimum criteria for operating reliability, and
(4) coordination agreements among BPA, scheduling utilities and other Federal agencies regarding resource and river operations.

(d) Any utility that has contractual or ownership rights to transmission capacity to Southwest utilities must be fully utilizing such capacity prior to receiving any access to BPA Intertie Capacity.

Section 4. Assured Delivery for Intertie Access

Subject to the limitations and other conditions in this section and in other sections of this policy, BPA has determined that it can provide Assured Delivery to Scheduling Utilities without causing substantial interference with the Administrator's Power Marketing Program.

(a) Access For Utilities Owning Or Controlling Southwest Interconnections

Assured Delivery is intended primarily for Scheduling Utilities which lack interconnections with the Southwest. A utility with transmission access to Southwest utilities, through contract or ownership, must utilize all such capacity on a firm basis before receiving any Assured Delivery. A utility is eligible for Assured Delivery only to the extent that the sum of its Exhibit B amounts exceeds its own transmission capacity to the Southwest.

(b) Waiver Of BPA Service Obligation. Assured Delivery contracts must contain a waiver of BPA's obligation under the Scheduling Utility's power sales contract, up to the amount of power for which firm Intertie access is provided.

(c) Transactions Not Subject To Exhibit B Limits Under This Policy

(1) Joint Ventures. Joint ventures between BPA and utilities, such as firm displacement contracts, which allow BPA to increase its sales of surplus power qualify for Assured Delivery.

(2) Sales In Lieu Of Exchanges. BPA may offer to satisfy Scheduling Utility demands for Seasonal Exchanges by selling them incremental amounts of surplus firm power during winter months. Upon committing to purchase such incremental firm power at negotiated prices that reflect BPA's lost opportunities for summer sales, a Scheduling Utility will qualify for Assured Delivery (with mitigation) to wheel an equal amount of firm capacity and energy over the Intertie during summer months.

(3) Conditions. A Scheduling Utility may request at any time the Assured Delivery of transactions identified in sections 4(c)(1) and 4(c)(2). Relevant contracts must be presented for review when Assured Delivery is requested. BPA will satisfy a request within 60 days after a Scheduling Utility has demonstrated satisfaction of the requirements of this policy.

(d) Transactions Subject To Exhibit B Limits Under This Policy

(1) Maximum Amounts Of Assured Delivery. BPA will provide 800 MW of Assured Delivery for transactions, limited by Exhibit B amounts, that are identified in this policy. BPA will determine the amount of any additional Assured Delivery increment after conclusion of the Third AC participation process. Moreover, the 800 MW amount may be subject to some reduction if the DC terminal expansion project is not completed on schedule.

(2) Firm Power Sales

(A) Existing Transmission Contracts. BPA will provide Assured Delivery for the remaining term of the firm power sale contract identified in Exhibit C to this policy.

(B) Exhibit B amounts.

(i) Current maximum. Each Scheduling Utility's maximum Assured Delivery amount for firm sales equals its average firm energy surplus, shown in Exhibit B to this policy. Except for Montana Power Company (MPC), Exhibit B represents projected Scheduling Utility surpluses for the 1988-89 operating year. In satisfaction of all obligations to MPC under Northwest Power Act section 9(i)(3), MPC's Exhibit B amount is set at 105 MW to facilitate long-term sales of firm power from its share of the Colstrip No. 4 coal-fired generating station.

(ii) Future changes. BPA may, at its discretion, revise Exhibit B to reflect changes in the firm power surpluses of individual utilities; however, the 361 MW Exhibit B average firm surplus total is not subject to increase. Any unutilized Assured Delivery amount is revoked if, upon revision, a utility's individual Exhibit B amount has declined or if a utility has sold firm power to another utility seeking to increase its Exhibit B average firm surplus amount. A Scheduling Utility may increase its individual Exhibit B amount by purchasing surplus firm power from BPA or any Scheduling Utility with an Exhibit B amount.

(iii) Nature Of Transactions. BPA will not provide Assured Delivery for transactions which a Scheduling Utility cannot demonstrate to be other than an advance arrangement to sell nonfirm energy. Nonfirm energy transactions may receive Intertie access only under section 5 of this policy.

(C) Shaping. Firm power sales eligible for Assured Delivery may be shaped within the following ranges. During the months of September through December, a Scheduling Utility may deliver firm energy at a rate up to 1.8 times its Exhibit B average firm surplus amount. During the months of January through August, a Scheduling Utility may deliver firm energy at a rate no greater than 1.0 times its Exhibit B amount. However, total delivered energy may not exceed the Exhibit B annual firm energy maximum.

(3) Seasonal Exchanges

(A) Existing Contracts. BPA will provide Assured Delivery for the remaining term of the Seasonal Exchange contracts identified in Exhibit C to this policy.

(B) Exhibit B Amounts. Subject to the individual utility Seasonal Exchange maximums in Exhibit B, BPA will provide Assured Delivery to facilitate Seasonal Exchanges of Qualified Northwest Resources. The current Exhibit B (representing Intertie Capacity Available for Assured Delivery) is subject to revision at the discretion of BPA.

(4) Mitigation

(A) Firm Sales And Seasonal Exchange Deliveries. During any hour in which BPA has invoked Condition 1 allocation procedures to preschedule energy deliveries, each utility's Assured Delivery amount shall be deducted from its formula allocation to determine its share of energy scheduled on the Intertie. If the remainder is negative for a given utility, then that utility must purchase sufficient energy from BPA, at BPA's then-applicable rate, to make up the difference.

(B) Seasonal Exchange Returns

(i) Returns. Exchange contracts must specify that all return energy be scheduled to either the AC Intertie point of interconnection at the California-Oregon border ("COB") or the DC Intertie point of interconnection at the Nevada-Oregon border ("NOB"). Exchange contracts must also specify prescheduled determinations of hourly energy returns.

(ii) Cash out. During any hour in which BPA has invoked Condition 1 or Condition 2 allocation procedures to preschedule energy deliveries, a utility may not utilize the cash-out provisions of a Seasonal Exchange contract. The rate of a cash out during Condition 3 shall not exceed than the rate at which the exchange return could have been scheduled.

(5) Satisfying Requests For Assured Delivery. To allow sufficient time for contract negotiation, initial requests under this

policy will be accepted until February 1, 1989. Thereafter, BPA will negotiate and execute Assured Delivery contracts. If Intertie Capacity remains available for Assured Delivery of transactions limited by Exhibit B amounts, subsequent requests must be received no later than 120 days before commencement of the next BPA operating year. All relevant power contracts must be presented for review no later than the date on which a request for Assured Delivery is made. BPA will not entertain Assured Delivery requests for firm power sales in excess of a utility's Exhibit B maximum.

Section 5. Formula Allocation

(a) Limits On Intertie Capacity Available For Formula Allocation. Generally, BPA will determine Intertie Capacity available for Formula Allocations after first taking into account the amount of Intertie Capacity necessary to satisfy requirements of the Administrator's Power Marketing Program, existing transmission contracts listed in Exhibit C, and Assured Delivery contracts executed by BPA pursuant to this policy. However, during Condition 1, BPA will not consider the Assured Delivery contracts subject to mitigation requirements in determining available Intertie capacity. BPA may reduce any allocation, if additional Intertie Capacity is required to minimize revenue losses associated with actions taken to protect fish in the Columbia River drainage basin.

(b) Northwest Scheduling Utility Requirements. BPA will make utilities aware of scheduling requirements before the policy is implemented.

(c) Allocation Methods.

(1) Condition 1

(A) Until December 31, 1988. Intertie Capacity will be allocated pursuant to the Exportable Agreement (BPA Contract No. 14-03-73155), when applicable.

(B) After December 31, 1988. Condition 1 will be in effect when the Federal system is in spill or in likelihood of spill, as determined by BPA. Available Intertie capacity will be allocated pursuant to the following procedure:

(i) Each hour, the maximum Condition 1 allocations for BPA and each Scheduling Utility will be based on the ratio of their respective hydroelectric generating capacities to the Northwest's total hydroelectric generating capacity, multiplied by the available Intertie capacity (the "Hydro Cap"). To the extent that the declarations of some Scheduling Utilities are less than their respective Hydro Caps, BPA will allocate the remainder, pro rata, to itself and to other Scheduling Utilities whose declarations are greater than, or equal to, their respective Hydro Caps. Examples of allocations under Condition 1 are shown in Exhibit A.

(ii) During Condition 1, whenever the Southwest market at BPA's applicable rate is less than the available Intertie capacity, BPA will allocate no more capacity than that market amount.

(iii) In calculating each Scheduling Utility's Hydro Cap, BPA will reduce the hydroelectric generating capacities of individual utilities by any Protected Area decrements determined pursuant to section 7.

(2) Condition 2

When Condition 1 is not in effect, but BPA and Scheduling Utilities declare amounts of energy that exceed available Intertie capacity, Formula Allocations for BPA and each Scheduling Utility will approximate, by hour, the ratio of each declaration to the sum of all declarations, multiplied by the available Intertie capacity. An example of an allocation under Condition 2 is shown in Exhibit A.

(3) Condition 3

When Condition 1 is not in effect and when the total surplus energy declared available by BPA and Scheduling Utilities is less than the total available Intertie Capacity, BPA and Scheduling Utilities' allocations will equal their declarations. The remaining Intertie capacity will be made available to Extraregional Utilities. Examples of the two possible allocation procedures under Condition 3 are shown in Appendix A.

(d) Modified Allocations Upon Commercial Operation Of the Third A.C. Interconnection. When the market power of California Intertie owners is reduced upon commercial operation of the third AC interconnection, BPA will cease allocating individual Intertie capacity amounts to non-Federal utilities during Conditions 2 and 3. Instead, after allocating sufficient capacity to itself, BPA will to the extent practicable make the remaining Intertie Capacity available as a block to Scheduling Utilities, and make any residual amount under Condition 3 available to Extraregional Utilities. However, this provision will not be operative if the Administrator determines that:

(1) even after commercial operation of the third AC, Intertie access continues to be impaired for California utilities presently lacking ownership in the southern portion of the Intertie, or

(2) Southwest utilities utilize some pro rata scheme to allocate energy purchases over the Intertie.

Section 6. Access for Qualified Extraregional Resources

(a) Assured Delivery. Any request for Assured Delivery of power from a Qualified Extraregional Resource would be granted only by contract which, in addition to the Mitigation measures specified in section 4(d)(4)(B), must include benefits to BPA such as increased storage, improved system coordination or operation, or other consideration of value commensurate with the services provided. However, Canadian Extraregional Utilities will not be provided Assured Delivery service until the Administrator has determined that the capability of the Intertie is rated at approximately 7,900 MW. Proposed contracts would be evaluated by BPA and reviewed publicly to determine whether

it would cause substantial interference with the Administrator's Power Marketing Program. An environmental review would also be conducted.

(b) Formula Allocation. Under Condition 3, energy from Canadian Qualified Extraregional Resources will have access to the Intertie to the extent that Intertie Capacity is available in excess of the amount used by BPA, Scheduling Utilities, and energy from U.S. Qualified Extraregional Resources. BPA may provide Qualified Extraregional Resources with some additional Formula Allocation, if the utility owner agrees by contract either to increased participation in the Pacific Northwest's coordinated planning and operation, or to provide other consideration of value, apart from the standard BPA wheeling rate, commensurate with the services provided.

Section 7. Fish and Wildlife Protection

(a) Purpose. Hydroelectric projects constructed in Protected Areas may substantially decrease the effectiveness of, or substantially increase the need for, expenditures and other actions by BPA, under Northwest Power Act section 4(h), to protect, mitigate or enhance fish and wildlife resources. Intertie access will not be provided to facilitate the transmission of power generated by any new hydroelectric projects located in Protected Areas, licensed after the effective date of this policy. Upon expiration of a Federal Power Act license for an existing project located within a Protected Area, BPA will assist the licensee in developing any necessary protective conditions so that the project may continue to qualify for Intertie access.

(b) Implementation. This policy contemplates that BPA will implement, after review and possible modification, a comprehensive protected area program adopted by the Pacific Northwest Electric Power and Conservation Planning Council. In the meantime, BPA will adopt the Protected Area designations compiled by the Council staff. Exhibit D lists those stream reaches, using Environmental Protection Agency stream reach codes, currently designated by BPA as protected areas.

(c) Enforcement. If a Scheduling Utility or Nonscheduling Utility owns, or acquires the output from, a hydroelectric project covered under the restrictions of section 7(a), BPA will reduce that utility's Assured Delivery capacity and the Formula Allocation made available to it under the Condition 1 Hydro Cap by either the nameplate rating of the project (in the case of ownership), or the amount of capacity acquired.

Section 8. Other Enforcement Provisions

Whenever the terms of this policy are not being met, BPA will inform the appropriate utility of the nature of the noncompliance and actions that may be taken to achieve compliance. If noncompliance is not corrected within a reasonable period, BPA may impose an appropriate sanction. Sanctions include denial of access for a resource and refusal to accept schedules.

EXHIBIT A
FORMULA ALLOCATION
EXAMPLE OF FORMULA ALLOCATION UNDER CONDITION 1

Assumptions Used in This Example

1. The Exportable Agreement has expired (post-12/31/88) and Condition 1 as proposed is in effect.

2. The available Intertie Capacity for Formula Allocations is 3300 MW.

3. No Assured Delivery contracts under the LTIAP have been negotiated.

4. Extraregional utilities are not allowed to declare or to receive an allocation under this condition.

Example of a Declaration and Allocation

(1) Util.	(2) Hydro Capacity*	(3) Max. Allocation	(4) Formula Declaration	(5) Initial Allocation	(6) Declarations Allocation	(7) Adjusted Allocation	(8) Final Allocation
IPC	1,660	171	1,000	171	171	16	187
MPC	193	20	400	20	20	2	22
PP&L	1,250	129	1500	129	129	12	141
PGE	1,150	119	0	0			0
PSP&L	1,800	186	700	186	186	17	203
WWP	1,140	119	600	119	119	11	130
CHN	270	28	25	25			25
CLDK	290	31	0	0			0
GRT	620	64	50	50			50
DGLS	200	21	100	21	21	2	23
COW	154	16	0	0			0
P.D.	0	0	0	0			0
SND	103	10	0	0			0
SCL	1,820	188	850	188	188	17	205
TCL	684	71	0	0			0
EWEB	81	8	0	0			0
BPA	20,485	2,119	9,500	2,119	2,119	195	2314
	31,900	3,300	14,725	3,028	2,953	272	3,300

* Utility's regional hydro capacity amounts are tentative pending release of the 1987 Pacific Northwest Coordination Agreement data.

Description

Column 1 = Utility declaring energy for Formula Allocation.

Column 2 = Utility's total regional Hydroelectric Capacity

Column 3 = Utility's maximum initial allocation computed on the available Intertie Capacity for Formula Allocation.

Formula: $$\frac{\text{Utility's regional hydro}}{\text{Total regional hydro}} \times \text{available Intertie Capacity}$$

Column 4 = Utility's declaration for Formula Allocation.

Column 5 = Initial allocation based on lesser of declaration (column 4) or allocations based on regional hydro capacity (column 3).

Column 6 = Utilities eligible for allocation adjustment due to other utilities not declaring energy available up to the amount of their column 3 allocations.

Column 7 = The pro rata adjustment to each initial allocation.

Formula: $$\frac{\text{eligible util. initial alloc.}}{\text{total elig. util. initial. alloc.}} \times \text{total capacity avail. for adjusted allocation.}$$

Column 8 = Utility's final allocation, limited to column 2.

EXAMPLE OF FORMULA ALLOCATION UNDER CONDITION 2

Assumptions used in this example:

1. Condition 1 is not in effect.

2. The hourly energy from Scheduling Utilities available at any price is greater than the available Intertie Capacity.

3. Available Intertie Capacity equals 3100 MW.

Assumptions:	Beginning total Intertie Capacity	5200 MW
	PGE capacity	700 MW
	PPL capacity	300 MW
	Loop flow and capacity reduction	500 MW
	Assured Delivery	600 MW
	Available Intertie Capacity	3100 MW

4. Extraregional Utilities are not able to declare or receive an allocation in this condition.

Example of the declaration and allocation:

(1)	(2) Energy Declaration	(3) Formula Allocation
BPA	2,000	904
IOU_1	1,300	587
IOU_2	1,960	886
IOU_3	400	181
PA_1	100	45
PA_2	200	90
PA_3	900	407
	6,860	3,100

Description:

Column 1 = Utility declaring energy for Formula Allocation.

Column 2 = Utility's energy declaration.

Column 3 = Final Formula Allocation for available Intertie Capacity.

Formula: $\frac{\text{Utility's declaration}}{\text{Total declarations}}$ X available Intertie Capacity

TWO EXAMPLES OF FORMULA ALLOCATION UNDER CONDITION 3

Assumptions used in example #1:

1. Scheduling Utilities do not declare enough energy to cover the available Intertie Capacity.

2. Scheduling Utilities and Extraregional Utilities (EXR) together declare energy in excess of available Intertie Capacity.

3. Available intertie capacity equals 3100 MW. (Same assumptions as in Condition 2.)

Example #1 of the hourly declaration and allocation:

(1)	(2) Energy Declaration	(3) Formula Allocation
BPA	200	200
IOU_1	500	500
IOU_2	1200	1,200
IOU_3	100	100
PA_1	50	50
PA_2	0	0
PA_3	250	250
Subtotal	2,300	2,300
EXR	1,200	800
	3,500	3,100

Assumptions used in example #2:

1. Scheduling Utilities and Extraregional Utilities together declare energy less than the available Intertie Capacity.

2. Available Intertie Capacity equals 3100 MW. (same assumptions as in example for Condition 2.)

Example #2 of the hourly declaration and allocation:

(1)	(2) Energy Declaration	(3) Formula Allocation
BPA	0	0
IOU_1	500	500
IOU_2	600	600
IOU_3	100	100
PA_1	0	0
PA_2	0	0
PA_3	150	150
Subtotal	1,350	1,350
EXR	1,000	1000
	2,350	2,350

Description for both example #1 and #2:

Column 1 = Utility declaring energy for Formula Allocation .

Column 2 = Each utility's energy declaration.

Column 3 = Final Formula Allocation for available Intertie Capacity.

EXHIBIT B
INTERTIE CAPACITY AVAILABLE FOR ASSURED DELIVERY

A. Average Firm Surplus Allocations:

UTILITY	AVERAGE FIRM SURPLUS
Chelan County PUD #1	10
Cowlitz County PUD #1	0
Douglas County PUD #1	0 1/
Eugene Water and Electric Board	14
Grant County PUD #1	26
Seattle City Light	23
Snohomish County PUD #1	0
Tacoma City Light	3 2/
Idaho Power Company	87
Montana Power Company	105 3/
Puget Sound Power and Light	0
Washington Water Power	93
	361

NOTE: The Average Firm Surplus is directly from the PNUCC Northwest Regional Forecast of March 1987 except as noted below. It includes resources operational on the effective date of this policy. Export contracts are included as loads.

1/ Douglas County PUD is 2; but Douglas has previously requested to a show zero Average Firm Surplus.

2/ Tacoma Average Firm Surplus shown in the Northwest Regional Forecast is in error.

3/ Montana Power Company's surplus was increased from 80 MW to 105 MW in settlement of obligations under Northwest Power Act section 9(i)(3).

B. Intertie Capacity Available for Seasonal Exchanges:

BPA will add numbers for utility Seasonal Exchange allocations when studies are completed on utility summer surplusses.

EXHIBIT C
EXISTING AGREEMENTS FOR INTERTIE CAPACITY

This is a list of existing BPA transmission contracts that were signed before the implementation of the Near-Term IAP and will continue to receive Intertie access under the Long-Term IAP.

Utility	BPA Contract No.	Expiration Date
Washington Water Power Company	DE-MS79-81BP90185	07/01/91
Washington Water Power Company	14-03-791101	09/01/88
Western Area Power Administration	DE-MS79-84BP91627	10/31/90

EXHIBIT D
PROTECTED AREAS

Exhibit D corresponds to the Northwest Power Planning Council protected area designations within the Columbia Basin, as specified in the Columbia River Basin Fish and Wildlife Program. Stream reaches designated as protected areas are identified by Environmental Protection Agency stream reach codes. Information about designations are contained on hard copy computer printouts or computer diskette copies which are available to the public upon request.

LIST OF PREPARERS

Chapter 6

LIST OF PREPARERS OF THE ENVIRONMENTAL IMPACT STATEMENT

Name	EIS Responsibility	Qualifications
BPA		
Gerard Bolden	FISHPASS Analysis	B.S., Electrical Engineering; BPA - 7 years Computer Specialist
Ron Brunner	Automated Data Processing Coordinator	B.S., Applied Science; BPA - 22 years ADP Coordination and Planning for the Office of Power Sales
Elizabeth Evans	Land Use and Nonrenewable Resources	B.S., Botany; Ph.D., Biology; Graduate Work in Planning and Economics; BPA - 1 1/2 year Work for Environmental Coordinator
Roy Fox	Management of Environmental Program	B.S., Economics; BPA - 3 years Environmental Economist; 1 year Conservation Program Manager; 3 year Manager Power and Resources Environmental Staff
James Geiselman	Fisheries Analyses	M.S., Environmental Engineering; BPA - 2 years Environmental Modeling; 3 year Hydro Operations and Fisheries Analysis
Phillip Havens	Threatened and Endangered Species Analysis	B.S., Biological Sciences; 24 years Profession Experience in Wildlife Issues
Cynthia Horvath	Economic Analysis	M.P.H., Biostatistics; BPA - 5 years Intertie and Marketing Analysis

Name	EIS Responsibility	Qualifications
Diana Jones	Economics Coordinator	B.S., Electrical Engineering; BPA - 12 years Hydraulic Engineer; 5 years Electrical Engineer; 7 years Supervisory Electrical Engineer
Pamela Kingsbury	Fish Studies, Recreation Studies, and Cultural Effects	M.S., Chemical Oceanography; Private - 3 years Environmental Consulting; BPA - 4 years Power Scheduler; 2 year work for Environmental Coordinator
Andrew Linehan	Assistant Project Coordinator	M.P.A., Public Policy Analysis; Public Policy Research - 2 years; BPA - 2 years Environmental and Policy Design Projects Related to Intertie Use
Michael McCoy	Modeling West Coast Operations	Post Doctoral, Operations Research; BPA - 3 years Transmission Planning and Reliability Analysis; BPA - 3 years Production Costs and Simulation, Project Management
Tom McKinney	Cultural Resource Consultation	B.A., Geography; BPA - 9 years Environmental Specialist
Carol Miller	Computer Processing of Recreation, Cultural Resources and Fish Studies	B.A., History; 22 years in Computer Field including, 12 years in Modeling of Environmental and Economic Systems
Sharron Monohon	System Analysis Model	B.S., Mathematics; BPA - 5 years Intertie and Marketing Analysis

Name	EIS Responsibility	Qualifications
Judith Montgomery	Project Managing Editor for Draft EIS	Ph.D., American Literature; BPA - 6 years Writing Consultant for Environmental Documents
Robert Neal	Hydro Operations Technical Support	B.S., Physics; BPA - 10 years Realtime Hydro Power Operations
Rick Pendergrass	Intertie Economics	B.S., Civil Engineering; BPA - 1 1/2 years Intertie Analyses
Barbara Pharayra	Export Sales and Generation	B.A., Philosophy; BPA 1-1/2 years Economic Analysis, 2 years Work for Environmental Coordinator
Randy Seiffert	Thermal Plant Effects	B.S., Chemical Engineering; BPA - 12 years in Environmental Issues
Gwen Shearer	System Analysis Model	B.A., Physics and Math; M.S., Energy and Resources; BPA - 3 years Rate Analyst; 6 years in Resource Planning
Stephen Smith	Fish & Wildlife Analysis	B.S., Wildlife and Fisheries Biology; USFWS - 1 year Fishery Biologist; NMFS - 8 years Fishery Biologist; BPA - 4-1/2 years Supervisory Fishery Biologist
Ralph Stein	System Analysis Model	B.S., Mathematics; BPA - 13 years Power System Model Development and Analysis
Chris Stoffels	Running of FISHPASS Model	B.S., Computer Science; BPA - 2 1/2 years Fish and Wildlife

Name	EIS Responsibility	Qualifications
John Taves	Project Manager	Ph.D., Sociology; BPA - 12 years Environmental and Rate Design Projects
Terry Thompson	System Analysis Model	B.S., Electrical Engineering; BPA - 12 years Hydro System Modeling
Kevin Ward	Vegetation and Wildlife Section	B.S., Resource Management; BPA - 3 years Environmental Specialist for Engineering; 1 year Environmental Specialist on Fish and Wildlife Program; 3 years Program Analyst for Environmental Coordinator
Don Weaver	Marketing LP Model	M.S., Mathematics Education; 9 years Teaching; BPA - 3 years
Susan Whittington	Editor for Final EIS	M.P.A., Environmental Management; 4 years Editorial Consulting; 4 years Energy Journalist; 6 years Federal and Local Government Policy Analysis

CONSULTANTS

Jerry Galm	Cultural Resources Analysis	PhD. Anthropology; 7 years Program Director of Archeological and Historical Services; 11 years Professor
Jeffrey Hagar	Fisheries & Water Quality Analysis	M.S., Zoology & Water Resources Management; Laboratory & Research Assistant - 4 years; Aquatic Ecologist - 1 year
George Hinman	Fuels and Air Quality Analysis	D.Sc., Physics; Research and Teaching - 30 years. Energy and Environmental Effects

Name	EIS Responsibility	Qualifications
Brian Lamb	Air Quality Analysis	Ph.D., Chemistry & Chemical Engineering; Research and Teaching - 6 years. Atmospheric Science
Clyde Mitchell	Assessment of Environmental Impacts from Changes in BC Hydro Operations	M. Eng., P. Eng.; Project Manager/Water Resources Engineer
Jeremy Pratt	Consultant Project Manager	M.S., Energy & Environmental Science
Robert Weisenmiller	California Utility Opertions Modeling	M.S., Energy & Resources; Ph.D., Chemistry; CEC-Program and Policy Evaluation; IPC-Studies of California Market for Power
David Yardas	California Utility Operations Modeling	M.S., Energy and Resources; Electric Utility Production Simulation and Financial Impact Analysis

(VS6-PG-1303I)

LIST OF AGENCIES, ORGANIZATIONS, AND PERSONS TO WHOM COPIES OF THE STATEMENT ARE SENT

Chapter 7

LIST OF AGENCIES, ORGANIZATIONS, AND PERSONS TO WHOM COPIES OF THE STATEMENT ARE SENT 1/

FEDERAL AGENCIES

Advisory Council on Historic Preservation, Golden, CO
Advisory Council on Historic Preservation, Washington, DC
US Attorney's Office, Portland, OR
US Environmental Protection Agency, Region X, Seattle, WA
US General Accounting Office, Portland, OR
US Army Corps of Engineers, Orofino, ID
US Army Corps of Engineers, Portland, OR
US Army Corps of Engineers, Newport, WA
US Army Corps of Engineers, Seattle, WA
US Army Corps of Engineers, Walla Walla, WA
US Navy, Bangor Naval Submarine Base, Bremerton, WA
USDA, Forest Service, Columbia Falls, MT
USDA, Forest Service, Hungry Horse, MT
USDA, Forest Service, Kalispell, MT
USDA, Forest Service, Libby, MT
USDA, Forest Service, PNW Forest & Range Exp Station, Portland, OR
USDA, Forest Service, Region 1, Missoula, MT
USDA, Forest Service, Region 4, Odgen, UT
USDA, Forest Service, Region 5, San Francisco, CA
USDA, Forest Service, Region 6, Portland, OR
USDA, Forest Service, Salmon, ID
USDA, Forest Service, Seattle, WA
USDA, Forest Service, Washington, DC
USDA, Office of the Secretary, Washington, DC
USDA, Soil Conservation Service, Portland, OR
USDOC, National Marine Fisheries Service, Hammond, OR
USDOC, National Marine Fisheries Service, Portland, OR
USDOC, National Oceanic & Atmospheric Administration, Portland, OR
USDOC, National Oceanic & Atmospheric Administration, Seattle, WA
USDOC, National Oceanic & Atmospheric Administration, Washington, DC
USDOE, Federal Energy Regulatory Commission, Portland, OR
USDOE, Federal Energy Regulatory Commission, Washington, DC
USDOE, Intergovernmental Affairs, Washington, DC
USDOE, Office of Communication, Richland, WA
USDOE, Western Area Power Administration, Sacramento, CA
USDOE, Western Area Power Administration, San Francisco, CA
USDOE, Western Area Power Administration, Golden, CO
USDOE, Western Area Power Administration, Billings, MT
USDOJ, Court of Appeals, San Francisco, CA

1/ A summary of the Final EIS was sent to a large number of potentially interested parties whose names do not appear on this list. They included businesses, individuals, interest groups, and universities.

USDOI, Bureau of Indian Affairs, Sacramento, CA
USDOI, Bureau of Indian Affairs, Lapwai, ID
USDOI, Bureau of Indian Affairs, Saint Ignatius, MT
USDOI, Bureau of Indian Affairs, Portland, OR
USDOI, Bureau of Indian Affairs, Toppenish, WA
USDOI, Bureau of Indian Affairs, Wapato, WA
USDOI, Bureau of Land Management, Sacramento, CA
USDOI, Bureau of Land Management, Boise, ID
USDOI, Bureau of Land Management, Billings, MT
USDOI, Bureau of Land Management, Butte, MT
USDOI, Bureau of Land Management, Lakeview, OR
USDOI, Bureau of Land Management, Medford, OR
USDOI, Bureau of Land Management, Portland, OR
USDOI, Bureau of Mines, Albany, OR
USDOI, Bureau of Mines, Spokane, WA
USDOI, Bureau of Reclamation, Sacramento, CA
USDOI, Bureau of Reclamation, Washington, DC
USDOI, Bureau of Reclamation, Boise, ID
USDOI, Bureau of Reclamation, Hungry Horse, MT
USDOI, Bureau of Reclamation, Ephrata, WA
USDOI, Bureau of Reclamation, Yakima, WA
USDOI, Fish and Wildlife Service, Sacramento, CA
USDOI, Fish and Wildlife Service, Boise, ID
USDOI, Fish and Wildlife Service, Billings, MT
USDOI, Fish and Wildlife Service, Portland, OR
USDOI, Fish and Wildlife Service, Cook, WA
USDOI, Fish and Wildlife Service, Olympia, WA
USDOI, Fish and Wildlife Service, Vancouver, WA
USDOI, Interagency Archeological Service, San Francisco, CA
USDOI, National Park Service, Coulee, WA
USDOI, National Park Service, Seattle, WA
USDOI, Office of Environmental Project Review, Washington, DC
USDOI, Office of the Secretary, Portland, OR
USDOT, Federal Aviation Administration, Seattle, WA
USDOT, Federal Highway Administration, Portland, OR
USDOT, Secretary, Washington, DC
USHUD, Seattle, WA

STATE LEGISLATORS

STATE OF IDAHO

Laird Noh, Senator, Boise
Gary Montgomery, Representative, Boise
Thomas Boyd, Representative, Boise
Dane H. Watkins, Senator, Idaho Falls
Mack Neibaur, Representative, Paul
Robert Geddes, Representative, Preston
House Committee on Agricultural Affairs, Boise
House Committee on Business, Boise
House Committee on Local Government, Moscow
House Committee on Resources and Conservation, Boise

Legislative Council, Boise
Senate Committee on Agricultural Affairs, Boise
Senate Committee on Commerce and Labor, Boise

STATE OF MONTANA

Joe Quilici, Representative, Butte
Dennis Iverson, Representative, Whitlash
House Committee on Agriculture Livestock and Irrigation, Helena
House Committee on Business and Labor, Helena
House Committee on Local Government, Helena
Senate Committee on Agriculture Livestock and Irrigation, Helena
Senate Committee on Fish and Game, Helena
Senate Committee on Local Government, Helena
Senate Committee on Public Welfare and Safety, Helena

STATE OF OREGON

Nancy Peterson, Representative, Ashland
Bill Bradbury, Representative, Bandon
Carl Hosticka, Representative, Eugene
Ron Cease, Representative, Portland
Larry Hill, Senator, Salem
Patti Greenfield, Office of the Senate, Salem
House Committee on Environment and Energy, Albany
House Committee on Trade and Economic Development, Salem

STATE OF WASHINGTON

Al Williams, Senator, Olympia
House Committee on Agriculture, Olympia
House Committee on Commerce and Labor, Olympia
House Committee on Environmental Affairs, Olympia
House Committee on Local Government, Olympia
House Committee on Trade and Economic Development, Olympia
House Energy and Utilities Committee, Olympia
House of Representatives District Office, Olympia
Parks and Recreation Commission, Olympia
Senate Committee on Agriculture, Olympia
Senate Committee on Commerce and Labor, Olympia
Senate Committee on Natural Resources, Olympia
Senate Committee on Parks and Ecology, Olympia
Senate Energy Committee, Olympia
Senate and House Energy and Utilities Commission, Olympia

STATE GOVERNORS

Governor of Arizona, Phoenix
Governor of California, Sacramento
Governor of Idaho, Boise
Governor of Montana, Helena
Governor of Nevada, Carson City

Governor of New Mexico, Santa Fe
Governor of Oregon, Salem
Governor of Utah, Salt Lake City
Governor of Washington, Olympia
Governor of Wyoming, Cheyenne

STATE OF ARIZONA

State Agencies

Arizona Corporation Commission, Utilities Division, Phoenix
Department of Archives & Public Records, Phoenix
Department of Health, Bureau of Air Quality Control, Phoenix
Division of Environmental Health Services, Phoenix
Energy Office, Phoenix
Natural Resources Division, Land Department, Phoenix
Oil & Gas Conservation Commission, Phoenix

STATE OF CALIFORNIA

State Agencies

Bureau of Public Utilities, Alameda
Department of Fish & Game, Sacramento
Department of Water Resources, Sacramento
Energy Commission, Sacramento
Energy Resource Conservation & Development, Sacramento
Office of Historic Preservation, Sacramento
Office of Planning and Research, Sacramento
Public Utilities Commission, San Francisco
Public Works Commission, San Francisco
Resources Agency of California, Sacramento
State of California Clearinghouse, Sacramento
Water Resources Control Board, El Macero

Local/County Agencies

City of Biggs
City of Riverside
City of Santa Clara
City of Vernon, El Monte

STATE OF IDAHO

State Agencies

Attorney General, Boise
Department of Commerce, Boise
Department of Fish & Game, Boise
Department of Fish & Game, Coeur D'Alene
Department of Fish & Game, Lewiston
Department of Water Resources, Boise
Office of Energy, Boise

Oregon/Idaho Regional Planning and Development Association, Weiser
Public Utilities Commission, Boise

Local/County Agencies

City of Lewiston
City of Moscow
City of Plummer
Clearwater Economic Development Association, Lewiston
County of Bonneville, Idaho Falls
County of Clearwater, Orofino
East Central Idaho Planning and Development Association, Rexburg
Greater Sandpoint Chamber of Commerce, Sandpoint
Orofino Chamber of Commerce
Panhandle Area Council, Hayden
Region IV, Development Association, Twin Falls
Southeast Idaho Council of Governments, Inc., Pocatello

STATE OF MONTANA

State Agencies

Department of Fish, Wildlife & Parks, Billings
Department of Fish, Wildlife & Parks, Helena
Department of Fish, Wildlife & Parks, Kalispell
Department of Natural Resources & Conservation, Helena
Department of Natural Resources & Conservation, Energy Division, Helena
Governors Office Interagency Review Team, Helena
Public Service Commission, Helena
Intergovernmental Review Clearinghouse, Helena

Local/County Agencies

Butte Silver Bow, Butte
City Commissioner, Helena
City Commissioner, Polson
City Council, Kalispell
City Council, Missoula
City County of Bozeman, Planning Board, Bozeman
City of Whitefish County Commissioners, Missoula
County of Granite, Office of Planning, Philipsburg
County of Granite, Phillipsburg
County of Jefferson, Boulder
County of Lewis & Clark, Department of Planning, Helena
County of Lincoln Board of Commissioners, Libby
County of Missoula, Missoula
Jefferson County Commissioner, Boulder
Montana Association of Counties, Helena
Montana Association of Counties, Havre
Montana League of Cities & Towns, Helena
Montana League of Cities & Towns, Missoula
Montana Local Government Energy Office, Missoula

STATE OF NEVADA

State Agencies

Division of Environmental Protection, Department of Conservation & Natural Resources, Carson City
Historic Preservation and Archeology Division, Carson City
Office of Community Service, Carson City
Public Service Commission, Carson City

Local/County Agencies

County of Elko, Board of Commissioners, Elko
County of Humboldt, Board of Commissioners, Winnemucca

STATE OF NEW MEXICO

State Agencies

Department of Energy and Minerals, Santa Fe
Energy Conservation & Management Division, Santa Fe
Energy Resource & Development Division, Santa Fe
Natural Resources Department, Santa Fe

STATE OF OREGON

State Agencies

Conservation Division, Salem
Department of Energy, Salem
Department of Economic Development, Salem
Department of Environmental Quality, Portland
Department of Fish & Wildlife, Clackamas
Department of Fish & Wildlife, Portland
Department of Forestry, Salem
Department of Land, Conservation, and Development, Salem
Department of Natural Resources, Salem
Intergovernmental Relations Division, Salem
Public Utilities Commission, Salem
State Forester, Salem
State Historic Preservation Officer, Salem

Local/County Agencies

Bend Urban Area Planning Commission, Bend
Blue Mountain Intergovernmental Council, Enterprise
Central Oregon Intergovernmental Council, Redmond
Chamber of Commerce, The Dalles
City of Klamath Falls
City of Portland
Clatsop Tillamook Intergovernmental Council, Cannon Beach
Coos Curry Council of Governments, Coos Bay

Council of Governments, Oregon District No. 4, Corvallis
County of Klamath, Klamath Falls
County of Jackson, Medford
County of Linn, Albany
County of Umatilla, Pendleton
East Central Oregon Association of Counties, Pendleton
Intergovernmental Project Review, Portland
Intergovernmental Project Review, Salem
Lane Council of Governments, Eugene
Metropolitan Service District, Portland
Mid-Columbia Council of Governments, The Dalles
Mid-Willamette Valley Council of Governments, Salem
Rogue Valley Council of Governments, Central Point
Umpqua Regional Council of Governments, Roseburg

STATE OF UTAH

State Agencies

Department of Natural Resources, Salt Lake City
Division of Environmental Health, Department of Health, Salt Lake City
Energy Office, Salt Lake City
Public Service Commission, Salt Lake City

STATE OF WASHINGTON

State Agencies

Department of Community Development, Intergovernmental Review Process, Olympia
Department of Employment Security, Olympia
Department of Fisheries, Olympia
Department of Fisheries Habitat Management Division, Tumwater
Department of Wildlife, Olympia
Energy Facility Site Evaluation Council, Olympia
NEPA Coordinator, Olympia
Office of Archeology & Historical Preservation, Olympia
Office of the Attorney General, Olympia
Office of Energy, Olympia
Office of Energy Library, Olympia
Office of Management and Budget, Seattle
Parks and Recreation Commission, Olympia
Utilities & Transportation Commission, Olympia

Local/County Agencies

City of Cheney
City of Davenport, Chamber of Commerce
City of Everett
City of Kettle Falls, Chamber of Commerce
Counties of Benton and Franklin Governmental Conference, Richland
County of Whatcom, Council of Governments, Bellingham
County of Adams, Department of Planning, Othello
County of Asotin, Planning Commission, Asotin

County of Chelan, Governmental Conference, Wenatchee
County of Island, Coupville
County of Kittitas, Office of Planning, Ellensburg
County of Lewis, Board of Commissioners, Chehalis
County of Lincoln, Creston
County of Okanogan, Department of Planning, Okanogan
County of Pacific, Regional Planning Council, South Bend
County of San Juan, Department of Planning, Friday Harbor
County of Whitman, Regional Planning Council, Colfax
Cowlitz Wahkiakum Governmental Conference, Kelso
Douglas Regional Planning Commission, East Wenatchee
Grays Harbor Regional Planning Commission, Aberdeen
Intergovernmental Resource Center, Vancouver
Jefferson Port Townsend Regional Council, Port Townsend
Klickitat Regional Council, Goldendale
Mason Regional Planning Council, Shelton
Puget Sound Council of Governments, Seattle
Skagit Council of Governments, Sedro Woolley
Skamania Regional Planning Council, Stevenson
Southwest Washington Health District, Vancouver Clark County
Health Center, Vancouver
Spokane Regional Planning Conference, Spokane
Thurston Regional Planning Council, Olympia
Trico Economic Development District, Colville
Walla Walla Regional Planning Council, Walla Walla
Yakima Valley Conference of Governments, Yakima

STATE OF WYOMING

State Agencies

Public Service Commission, Cheyenne

Local/County Agencies

County of Lincoln, Uinta Association of Governments, Kemmerer

CANADA

BC Utilities Commission, Vancouver, BC
Canadian Consulate General, Seattle, WA
Department of Fisheries and Oceans, Vancouver, BC
Ministry of Energy, Policy Development Branch, Victoria, BC
Parliamentary Assistant, House of Commons, Ottawa, Canada

BPA'S CUSTOMERS

ALCOA, Vancouver, WA
ALCOA, Wenatchee, WA
Alder Mutual Light Company, Eatonville, WA

Alumax, Inc., San Mateo, CA
BC Hydro & Power Authority, Vancouver, BC
Benton County PUD No. 1, Kennewick, WA
Benton Rural Electric Association, Prosser, WA
Big Bend Electric Coop, Inc., Ritzville, WA
Blachly Lane County Coop, Eugene, OR
Bountiful City Light & Power, Bountiful, UT
CP National Corp, Baker, OR
CP National Corp, Medford, OR
Canby Utility Board, Canby, OR
Central Electric Coop, Inc., Redmond, OR
Central Lincoln PUD, Newport, OR
Chelan County PUD No. 1, Wenatchee, WA
City of Albion, Albion, ID
City of Anaheim, Anaheim, CA
City of Ashland, Ashland, OR
City of Bandon, Bandon, OR
City of Blaine, Blaine, WA
City of Bonners Ferry, Bonners Ferry, ID
City of Burbank, Burbank, CA
City of Burley, Burley, ID
City of Cascade Locks, Cascade Locks, OR
City of Centralia, Centralia, WA
City of Chewelah, Chewelah, WA
City of Coulee Dam, Coulee Dam, WA
City of Declo, Declo, ID
City of Drain, Drain, OR
City of Ellensburg, Ellensburg, WA
City of Forest Grove, Forest Grove, OR
City of Glendale, Glendale, CA
City of Healdsburg, Healdsburg, CA
City of Heyburn, Heyburn, ID
City of Idaho Falls, Idaho Falls, ID
City of Lodi, Lodi, CA
City of Lompoc, Lompoc, CA
City of McMinnville, McMinnville, OR
City of Minidoka, Minidoka, ID
City of Monmouth, Monmouth, OR
City of Pasadena, Pasadena, CA
City of Port Angeles, Port Angeles, WA
City of Richland, Richland, WA
City of Roseville, Roseville, CA
City of Rupert, Rupert, ID
City of Soda Springs, Soda Springs, ID
City of Sumas, Sumas, WA
City of Ukiah, Ukiah, CA
Clallam County PUD No. 1, Port Angeles, WA
Clark County PUD #1, Vancouver, WA
Clatskanie PUD, Clatskanie, OR
Columbia Basin Electric Coop, Heppner, OR
Columbia Power Coop Assn, Monument, OR
Columbia River PUD, St Helens, OR

Columbia Rural Electric Assoc, Inc., Dayton, WA
Consolidated Irrigation Dist 19, Greenacres, WA
Consumer Power, Inc., Philomath, OR
Coos Curry Electric Coop, Inc., Port Orford, OR
Cowlitz County PUD No. 1, Longview, WA
Department of Water Resources, Sacramento, CA
Direct Services Industries, Inc., Portland, OR
Douglas County PUD, Wenatchee, WA
Douglas County PUD #1, East Wenatchee, WA
Douglas Electric Coop, Inc., Roseburg, OR
E End Mutual Electric Co., Ltd, Rupert, ID
Elmhurst Mutual Power & Light Co., Tacoma, WA
Emerald PUD, Eugene, OR
Eugene Water & Electric Board, Eugene, OR
Fall River Rural Electric Coop, Inc., Ashton, ID
Ferry County PUD No. 1, Republic, WA
Flathead Electric Coop, Inc., Kalispell, MT
Franklin County PUD, Pasco, WA
Georgia Pacific Corp., Bellingham, WA
Georgia Pacific Corp., Portland, OR
Gilmore Steel Corporation, Portland, OR
Glacier Electric Coop., Inc, Cut Bank, MT
Grant County PUD #2, Ephrata, WA
Grays Harbor County PUD #1, Aberdeen, WA
Gridley Municipal Utilities, Gridley, CA
Hanna Mining Co., Cleveland, OH
Harney Electric Coop, Inc., Burns, OR
Hood River Electric Coop, Odell, OR
Idaho Coop Utilities, Lewiston, ID
Idaho County Light & Power, Grangeville, ID
Idaho Power Co., Boise, ID
Inland Power & Light Co., Spokane, WA
Intalco Aluminum Corporation, Ferndale, WA
Intercompany Pool, Spokane, WA
Kaiser Aluminum & Chemical Corp., Mead, WA
Kaiser Aluminum & Chemical Corp., Portland, OR
Kaiser Aluminum & Chemical Corp., Oakland, CA
Kaiser Aluminum & Chemical Corp., Tacoma, WA
Kaiser Aluminum & Chemical Corp., Trentwood, WA
Kaiser Aluminum & Chemical Corp., Vancouver, WA
Kaiser Aluminum & Chemical Corp., Tacoma, WA
Kittitas County PUD No. 1, Ellensburg, WA
Klickitat County PUD, Goldendale, WA
Kootenai Electric Coop, Inc., Hayden Lake, ID
Lakeview Light & Power Company, Tacoma, WA
Lane Electric Coop, Inc., Eugene, OR
Lewis County PUD, Chehalis, WA
Lincoln Electric Coop, Eureka, MT
Lincoln Electric Coop, Inc., Davenport, WA
Longview Fibre Co., Longview, WA
Los Angeles Department of Water & Power, Los Angeles, CA
Lost River Electric Coop, Inc., Mackay, ID

Lower Valley Power & Light, Inc., Afton, WY
Martin Marietta Corporation, Bethesda, MD
Mason County PUD #1, Belfair, WA
Mason County PUD #1, Shelton, WA
Mason County PUD #1, Union, WA
Mason County PUD #3, Shelton, WA
McCleary Light and Power, McLeary, WA
Mid-Columbia PUD Reg Coord Office, Portland, OR
Midstate Electric Coop, Inc., La Pine, OR
Milton Freewater Light & Power, Milton Freewater, OR
Missoula Electric Coop, Inc., Missoula, MT
Modern Electric Water Company, Spokane, WA
Montana Light & Power, Libby, MT
Montana Power Company, Butte, MT
Montana Power Company, Missoula, MT
NW Utilities, Tacoma, WA
Naval Radio Station T, Oso, WA
Nespelem Valley Electric Coop, Inc., Nespelem, WA
Nickel Mountain Resources Co., Riddle, OR
NonGenerating Public Utilities, Portland, OR
Northern California Power Agency, Roseville, CA
Northern Lights, Inc., Sandpoint, ID
Northern Wasco County PUD, The Dalles, OR
Northwest Aluminum Co., Portland, OR
Northwest Public Power Association, Vancouver, WA
Ohop Mutual Light Co., Eatonville, WA
Okanogan County Electric Coop, Inc., Winthrop, WA
Okanogan County PUD #1, Okanogan, WA
Orcas Power & Light Company, Eastsound, WA
Oregon Metallurgical Company, Albany, OR
Pacific County PUD #2, Raymond, WA
Pacific Gas & Electric Company, San Francisco, CA
Pacific Gas Transmission Co., San Francisco, CA
Pacific Power & Light Company, Portland, OR
Parkland Light & Water Company, Tacoma, WA
Pend Oreille County PUD No. 1, Newport, WA
Peninsula Light Company, Gig Harbor, WA
Pennwalt Corp, Tacoma, WA
Pennwalt Corp, Portland, OR
Port Townsend Paper Corporation, Bainbridge Island, WA
Portland General Electric, Portland, OR
Prairie Power Cooperative, Inc., Fairfield, ID
Puget Sound Power & Light Company, Bellevue, WA
Raft River Rural Electric Coop, Malta, ID
Ravalli County Electric Coop., Inc., Corvallis, MT
Reynolds Metals Co., Longview, WA
Reynolds Metals Co., Portland, OR
Reynolds Metals Co., Troutdale, OR
Reynolds Metals Co., Richmond, VA
Riverside Electric Company, Rupert, ID
Rural Electric Company, Rupert, ID
Sacramento Municipal Utility Dist, Sacramento, CA

Salem Electric, Salem, OR
Salmon River Electric, Challis, ID
San Diego Gas & Electric, San Diego, CA
Seattle City Light Company, Seattle, WA
Sierra Pacific Power Co., Reno, NV
Skamania County PUD, Carson, WA
Snohomish County PUD #1, Everett, WA
South Columbia Basin Irrigation District, Pasco, WA
South Side Electric Lines, Inc., Declo, ID
Southern California Edison Company, Rosemead, CA
Springfield Utility Board, Springfield, OR
Surprise Valley Elec Coop, Alturas, CA
Tacoma City Light Company, Tacoma, WA
Tanner Electric, North Bend, WA
Tillamook County PUD, Tillamook, OR
Town of Eatonville Power & Light, Eatonville, WA
Town of Milton, WA
Town of Steilacoom, WA
Town of Waterville, WA
USAF, Fairchild AFB, WA
USN Puget Sound Naval Shipyard, Bremerton, WA
US Naval Facilities Engineering Command, San Bruno, CA
US Navy, Jim Creek Naval Radio Station, Oso, WA
Umatilla County PUD, Milton-Freewater, OR
Umatilla Electric Coop Assn, Hermiston, OR
Unity Light & Power Company, Burley, ID
Utah Power & Light Co., Salt Lake City, UT
Vanalco, Inc., Vancouver, WA
Vera Irrigation Dist #15, Veradale, WA
Vigilante Electric Coop, Inc., Dillon, MT
Wahkiakum County PUD, Cathlamet, WA
Wasco Electric Coop, Inc., The Dalles, OR
Washington PUD Association, Seattle, WA
Washington Public Power Supply System, Richland, WA
Washington Water Power Company, Spokane, WA
Wells Rural Electric Company, Wells, NV
West Kootenay Power & Light, Trail, BC
West Oregon Electric Coop, Inc., Vernonia, OR
Whatcom County PUD, Ferndale, WA

UTILITIES & UTILITY ASSOCIATIONS

Central Oregon PUD, Bend, OR
Cominco, Ltd. Utility Services, BC, Canada
Industrial Customers of NW Utilities, Portland, OR
Intercompany Pool, Spokane, WA
Northwest Irrigation Utilities, Richland, WA
Northwest Irrigation Utilities, Portland, OR
Northwest Natural Gas, Portland, OR
Northwest Power Pool, Portland, OR
Oregon Municipal Utilities, Salem, OR
Oregon PUD Association, Salem, OR

Oregon Rural Electric Co-op Association, Salem, OR
Pacific Northwest Generating Company, Portland, OR
Pacific Northwest Utilities Conference Committee, Portland, OR
Public Generating Pool, Portland, OR
Public Power Council, Portland, OR
Sierra Pacific Power Company, Reno, NV
Transalta Utilities Corp., Calgary, Canada
Western Public Agencies Group, Mill Creek, WA

BUSINESSES

ACPC, Inc., Vancouver, WA
American Piping and Boiler Company, Honolulu, HI
Argonne National Laboratory, Portland, OR
Bacon and Hunt, Inc., Portland, OR
Basin Electric Power Coop, Bismarck, ND
Battelle Pacific NW Labs, Richland, WA
Bistline Law Office, Boise, ID
Boeing Aerospace Company, Seattle, WA
Bogle & Gates, Seattle, WA
Buell and Associates, Inc., Beaverton, OR
C. Grist Energy Consulting, Portland, OR
California Energy Company, Santa Rosa, CA
Camas Associates, Roseburg, OR
Chadbourne Parke, New York, NY
CH2M Hill, Boise, ID
Chickering & Gregory, San Franciso, CA
Cogeneration Services, Inc., Portland, OR
Columbia Gas System Service Corp., Wilmington, DE
Cross Engineers, Inc., Tacoma, WA
Culp, Dwyer, Gutterson, & Grader, Seattle, WA
Dezendorf Et Al, Portland, OR
Don Chapman Consultants, Inc., McCall, ID
ECO Northwest, Eugene, OR
Ebasco Services, Bellevue, WA
Ecology and Environment, Buffalo, NY
Energy Management Associates, Santa Clara, CA
Engineering and Design Association, Inc., Tigard, OR
Evergreen Legal Services, Seattle, WA
Farmers Electric Co., Rupert, ID
G. H. Bowers Engineering, Seattle, WA
GEO Newberry Crater, Inc., Bend, OR
Gary Danielson and Associates, Inc., Jamestown, CA
Geo Operation Corp., San Mateo, CA
Geothermal Resources International, San Mateo, CA
Glacier Energy Company, Maple Falls, WA
Golderg, Fieldman & Letham PC, Washington, DC
Gordon Taylor Associates, Inc., Portland, OR
H. H. Burkitt Project Management, Inc., Portland OR
Heller Ehrman White & McAuliffe, Portland, OR
Heller Ehrman White & McAuliffe, Seattle, WA

Humboldt Research Associates, Inc., Walnut Creek, CA
Hydro West Group, Inc., Bellevue, WA
Idaho Mining Association, Boise, ID
Independent Power Corp., Oakland, CA
Intermountain Gas Co., Boise, ID
JBS Energy, Inc., West Sacramento, CA
Jaqua, Wheatly, Gallagher, & Holland, Eugene, OR
John Nureen & Company, Seattle, WA
Jones, Grey & Bayley PS, Seattle, WA
KINK, News Director, Portland, OR
KPTV Channel 12, News Director, Portland, OR
La Grande Clinic, La Grande, OR
Lindsay Hart Neil & Weigler, Portland, OR
Lindsay Hart Neil & Weigler, Boise, ID
Lloyd Controls, Inc., Mountlake Terrace, WA
Logan Associates, Sacramento, CA
MCR Geothermal Corp., Los Angeles, CA
Magma Power Co., Los Angeles, CA
Mail Tribue, News Editor, Medford, OR
Methven and Associates, Federal Way, WA
Mission Energy Company, Irvine, CA
Modesto Irrigation District, Modesto, CA
Morrison Knudsen Power Eng., Boise, ID
Morse, Richard, Miller, Weisen, and Associates, Oakland, CA
Mt. Spokane Enterprises, Spokane, WA
Newman and Holtzinger PC, Washington, DC
Northwest Resource Information Center, Eagle, ID
Oppenheimer and Company, Inc., New York, NY
Paine, Hamblen, Coffin, and Brooke, Spokane, WA
Potomac Management Group, Alexandria, VA
Power Engineers, Inc., Hailey, ID
Preston, Thorgrimson, Ellis, Holman, Seattle, WA
QED Research, Palo Alta, CA
Quilici Glass, Butte, MT
R. L. Mitchell & Assoc, Manhattan Beach, CA
R. W. Beck & Associates, Seattle, WA
R. W. Beck & Associates, Sacramento, CA
Reid and Priest, Washington, DC
Resource Management Int'l., Sacramento, CA
Riddell, Williams, Bullet, and Walkenshaw, Seattle, WA
S&W Enterprises, Mukilteo, WA
Sartron, Inc., Newberg, OR
Schwabe, Williamson and Wyatt, Portland, OR
Seattle Times, Seattle, WA
Shapiro & Associates, Seattle, WA
Shawinigan Integ, Vancouver, BC, Canada
Sierra Energy & Risk Assessment, Sacramento, CA
Slotta Engineering Association, Inc., Corvallis, OR
Small Hydro Systems and Equipment, Inc., Bellingham, WA
Sol Earth, Inc., Coeur d'Alene, ID
Spears Lubersky, et al., Portland, OR
Spensley, Horn, Jubas, and Lubitz, Los Angeles, CA

Spiegel & McDiarmid, Washington, DC
Standard Oil Company, Niagara Falls, NY
Stoel, Rives, Boley, Jones, and Grey, Portland, OR
Stoll & Stoll, PC, Portland, OR
Sustainable Resource Development Group, Underwood, WA
Thermal Power Company, San Francisco, CA
Thomson McKinnon Securities, Inc., New York, NY
Touche Ross and Company, Seattle, WA
Turlock Irrigation District, Turlock, CA
Union Oil Co., Santa Rosa, CA
Union Oil Company of California, Los Angeles, CA
Unitel, Los Angeles, CA
Utility Data Institute, Washington, DC
Weyerhauser Co., Tacoma, WA

INTEREST GROUPS

1000 Friends of Oregon, Portland, OR
Association of Idaho Cities, Moscow, ID
Association of Idaho Cities, Boise, ID
Association of Oregon Counties, Salem, OR
Association of Washington Cities, Yakima, WA
Association of Washington Cities, Seattle, WA
Association of Western Pulp & Paper Workers, Portland, OR
Audubon Society, Seattle, WA
Citizens Utility Council, Wallace, ID
Clearing Up, Seattle, WA
Coalition to Protect Park Resources, Hungry Horse, MT
Columbia Basin Fish & Wildlife Authority, Portland, OR
Columbia River Citizens Compact, Portland, OR
Columbia River Inter-Tribal Fish Commission, Portland, OR
Common Cause, Challis, ID
Common Cause, Eugene, OR
Common Cause, Olympia, WA
Don't Bankrupt Washington, Seattle, WA
Environmental Defense Fund, Washington, DC
Environmental Defense Fund, Oakland, CA
Environmental Information Center, Helena, MT
Eugene Future Power Commission, Eugene, OR
Fair Electric Rates Now, Olympia, WA
Flathead Basin Commission, Polson, MT
Forelaws on Board, Boring, OR
Friends of the Earth, Seattle, WA
Friends of the Greensprings, Ashland, OR
Grey Panthers of Portland, Portland, OR
Idaho Citizens Coalition, Boise, ID
Idaho Conservation League, Boise, ID
Idaho Consumer Affairs Inc., Boise, ID
Idaho Consumer Affairs, Inc., Nampa, ID
Idaho Steelhead and Salmon Unlimited, Boise, ID
Izaac Walton League of America, Inc., Portland, OR
League of Oregon Cities, Hillsboro, OR

League of Women Voters of Montana, Missoula, MT
League of Women Voters, Bend, OR
League of Women Voters, Salem, OR
Libby Creek Watershed Association, Carlton, WA
National Wildlife Federation, Portland, OR
Natural Resources Defense Council, San Francisco, CA
Natural Resources Law Institute, Portland, OR
Natural Resources, Vancouver, WA
Nature Conservancy, Seattle, WA
Northern Plains Resource Council, Billings, MT
Northwest Conservation Act Coalition, Seattle, WA
Northwest Pulp & Paper Association, Bellevue, WA
Northwest Resource Information Center, Eagle, ID
OSPIRG, Portland, OR
Oregon Environmental Council, Portland, OR
Oregon Natural Resources Council, Bend, OR
Oregon Review Committee, Malin, OR
Oregon Student Public Interest Research Group, Portland, OR
Oregon Transmission Committee, Keno, OR
Oregon Water Watch, Inc., Hillsboro, OR
Plumas Sierra Rural Electric Coop, Portola, CA
Resources of the Future, Washington, DC
Robert L. Teeter, Inc., McLean, VA
Save Our Klamath River, Klamath Falls, OR
Sierra Club, Corvallis, OR
Sierra Club, Klamath Falls, OR
Sierra Club, Missoula, MT
Sierra Club, Oakland, CA
Sierra Club, Portland, OR
Sierra Club, Seattle, WA
Soda Mountain Wilderness Council, Ashland, OR
Spokane Canoe and Kayak Club, Inc., Spokane, WA
USED, Stevenson, WA
Washington Environmental Council, Seattle, WA
Washington Wilderness Coalition, Seattle, WA
Wilderness Society, Portland, OR

LIBRARIES/COLLEGES

Aberdeen Timberland Library, Aberdeen, WA
Boise Public Library, Boise, ID
Boise State University Library, Boise, ID
Butte Silver Bow Public Library, Butte, MT
California State University Library, Documents Section, Sacramento, CA
Carroll College Library, Helena, MT
Central Washington University Library, Ellensburg, WA
Clark County Library, Las Vegas, NV
College of Southern Idaho Library, Twin Falls, ID
Colorado State University, Fort Collins, CO
Denver Public Library, Regional Depository, Denver, CO
Eastern Montana College Library, Billings, MT

Eastern Oregon College Library, La Grande, OR
Eastern Washington University Library, Biology Fishery Research Center, Cheney, WA
Eastern Washington University Library, Cheney, WA
Everett Public Library, Everett, WA
Evergreen State College Library, Olympia, WA
Fort Vancouver Regional Library, Vancouver, WA
Hot Springs Public Library, Hot Springs, MT
Idaho State Library, Boise, ID
Idaho State University, Department of Biology, Pocatello, ID
Idaho State University, Museum, Pocatello, ID
KSOR, Southern Oregon College, Ashland, OR
Kitsap Regional Library, Bremerton, WA
Laboratory of Anthropology, Moscow, ID
Lewis & Clark College Library, Portland, OR
Lewis and Clark College, Department of Political Science, Portland, OR
Library Association of Portland, Portland, OR
Library FOI DOE MA 232.1, Washington, DC
Linfield College Library, McMinnville, OR
Lopez Island Library, Lopez Island, WA
Los Angeles Public Library, Los Angeles, CA
Mid-Columbia Library, Kennewick, WA
Missoula City-County Library, Missoula, MT
Montana College of Mineral Science & Technology Library, Butte, MT
Montana Historical Society Library, Helena, MT
Montana State Library, Helena, MT
Montana State University Library, Bozeman, MT
Municipal Research and Services Center Library, Seattle, WA
North Olympic Library System, Port Angeles, WA
Northern Arizona University Library, Flagstaff, AZ
Northern Montana College Library, Havre, MT
Northwestern School of Law Library, Portland, OR
OSU Extension Service, Land Use Training Program, Corvallis, OR
Oregon College of Education Library, Monmouth, OR
Oregon Institute of Technology, Klamath Falls, OR
Oregon State Library, Salem, OR
Oregon State University Library, Corvallis, OR
Oregon State University, Kerr Library Documents Division, Corvallis, OR
Oregon Supreme Court Library, Salem, OR
Pacific University Library, Forest Grove, OR
Pierce County Rural Library District, Tacoma, WA
Port Angeles Public Library, Port Angeles, WA
Portland State University Library, Portland, OR
Reed College Library, Portland, OR
Ricks College, McKay Library, Rexburg, ID
San Diego County Law Library, San Diego, CA
San Diego State University Library, San Diego, CA
San Francisco Public Library, San Francisco, CA
Seattle Public Library, Seattle, WA
Shasta County Library, Redding, CA
Southern Oregon State College Library, Ashland, OR

Spokane Public Library, Spokane, WA
State of Arizona Regional Depository Library, Phoenix, AZ
State of California Library, Sacramento, CA
State of Washington Regional Depository, Olympia, WA
Tacoma Public Library, Tacoma, WA
US Court of Appeals, 9th Circuit Library, Seattle, WA
University of Arizona Library, Tucson, AZ
University of California at Los Angeles, Research Library, Los Angeles, CA
University of Idaho College of Law, Moscow, ID
University of Idaho Library, Moscow, ID
University of Montana Library, Missoula, MT
University of Montana, Biological Station, Bigfork, MT
University of Nevada Library, Reno, NV
University of New Mexico, Albuquerque, NM
University of Oregon Libraries, Eugene, OR
University of Oregon, Bureau of Governmental Research and Science, Eugene, OR
University of Oregon, Survival Center, Eugene, OR
University of Puget Sound Library, Tacoma, WA
University of Puget Sound Law Library, Tacoma, WA
University of Washington Libraries, Seattle, WA
University of Washington, Department of Geography, Seattle, WA
University of Washington, Institute for Environmental Studies, Seattle, WA
University of Washington, School of Fisheries, Seattle, WA
Utah State Library, Salt Lake City, UT
Utah State University Library, Logan, UT
Washington State Library, Olympia, WA
Washington State University, Center for Pacific Northwest Studies, Bellingham, WA
Washington State University, Department of Economics, Bellingham, WA
Washington State University Library, Pullman, WA
Washington State University, Office of Applied Energy Studies, Pullman, WA
Western Oregon State College Library, Monmouth, OR
Western Washington University Library, Bellingham, WA
Western Washington University, Huxley College Environmental Resource Center, Bellingham, WA
Whitman College Library, Walla Walla, WA
Willamette University Law Library, Salem, OR
Willamette University Library, Salem, OR
Wyoming State Library, Cheyenne, WY

INDIVIDUALS

H.C. Allen
Rick Bauman
Joseph Barchtold
V. Blankenship
Paula Blaydes
George Blount
James D. Bollin
John A. Bower
Bruce Bowler

Mathew V. Brady
Allen Brown
David Brown
Sonya Bruce
Ralph L. Bunnell
Norma Jean Cameron
Dave E. Campbell
Paul Converse
Judy Converse
Gale C. Corson
M.E. Covert
Stuart Davies
William W. Deboer
Harold Deery
Peggy Wells Dobbins
Leslie E. Downing
Doug Frank
Georgia J. Frazier
David Fromer
Wendy Fullerton
Loren Goldberg
Walter S. Gordon
Sandra Grady
Ronald Gross
Robert M. Hall
M. Herron
Jan Howell
Barry Hyman
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Eric Weber
Walter J. Widmer
Ralph Zusman

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Affiliated Tribes of Northwest Indians, Portland, OR
Coeur D'Alene Tribe, Plummer, ID
Confederated Salish & Kootenai Tribes, Pablo, MT
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Duckwater Shoshone Council, Duckwater, NV
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OTHER

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GLOSSARY

Chapter 9

G L O S S A R Y

The words below are defined for the reader as they are used in this environmental impact statement.

AC - (see <u>Alternating current</u>)

aMW - (see <u>Average megawatts</u>)

Absolute - Being fully as indicated; independent of any other value or standard; not comparative or relative (opposed to relative).

Access - (see <u>Intertie access</u>)

Acid deposition - The combination of oxides of nitrogen and sulfur, in the air, with water, forming acid rain or snow, which may adversely affect water resources and plant and animal life.

Acre-foot - The volume of water that will cover an area of 1-acre to a depth of 1 foot.

Air basins - Defined areas which generally confine the air-borne pollutants produced within them. Air pollutants tend to circulate and mix together within a basin.

Alluvial fan - A low cone-shaped deposit of sediment laid down by a swift-flowing stream as it enters a plain or an open valley, commonly in dry regions with interior drainage.

Alpha - In the field of statistics, the probability (percentage) of erring by rejecting the null hypothesis when it is actually true.

Alternating current (AC) - Term applied to an electric current or voltage that reverses its direction of flow at regular intervals and has alternately positive and negative values, the average value of which (over a period of time) is zero.

Ambient Air - Ambient air is the air surrounding a particular spot, such as a power plant.

Anadromous Fish - Fish species that spawn and initially rear in fresh water, migrate and mature in the ocean and return to fresh water as adults.

Applicable rate - The rate(s) contained in rate schedules for service of a defined type.

Aquatic biota - The plant and animal life of a water body, considered as a total ecological entity.

Aquifer - Any geological formation containing water, especially one that supplies water to wells, springs, etc.

Artifact - An object of any type made by human hands. Tools, weapons, pottery, and sculptured and engraved objects are representative artifacts.

Assured (Intertie) access - The guaranteed assigned right to send a defined amount of electric power at a certain time over the high-voltage line system called the Pacific Northwest-Pacific Southwest Intertie.

Assured firm sales - Sales of power on a guaranteed basis for a specified length of time, pursuant to a contract.

Average megawatts (aMW) - The average amount of energy (number of megawatts) supplied or demanded over a specified period of time.

Avoided-cost methodology - A method used to determine the payments from utilities to qualifying facilities (QF's) under PURPA. The utility pays the QF an amount based on the costs for power the utility avoids by purchasing power from the QF.

Baseload - In a demand sense, a load that varies only slightly in level over a specified time period. In a supply sense, a plant that operates most efficiently at a relatively constant level of generation.

Benthic insects - Insects living on the bottom of reservoirs or streams.

Block slump - The (usually limited) downward displacement of a mass of earth as a unit, often caused by excessive soil saturation.

Boreal - Pertaining to the forest areas and tundras of the North Temperate zone and Arctic region.

Bottom-ash - Uncombusted materials which accumulate in the bottom of a boiler and which must be removed and, generally, disposed of as solid waste.

Brackish - Containing some salt. Brackish water often results where fresh waters meet the ocean.

Buffering capability - The ability of a material to resist a change in pH (acidity or basicity) when an acid or base is added.

Bypass - Water released from a project which does not go through the turbines or over the spillway. Bypass may include leakage, navigation lock releases, and fish ladders.

cfs - (see Cubic feet per second)

CFM VI - (see Common Forecasting Methodology VI)

Capacity - The amount of power that can be produced by a generator or carried by a transmission facility at any instant. Also, the service whereby one utility delivers firm energy during another utility's period of peak usage with return made during the second utility's offpeak periods; compensation for this service may be with money, energy or other services.

Capacity additions - Proposals to increase the power carrying capability of the Intertie--the Third AC/COTP and the DC Terminal Expansion Project.

Capacity/energy exchange - A transaction in which one utility provides another with capacity service in exchange for additional amounts of firm energy (exchange energy) usually during offpeak hours or money under specified conditions.

Capacity/energy diversity exchange - A transaction in which one utility provides another with capacity service during its peak season, with compensation as the delivery of additional amounts of energy to the first utility during its peak season. This type of exchange benefits utilities that do not peak at the same time, if deliveries and returns can be made at the time of each utility's system peak.

Capital costs - The costs to construct a power plant, including the costs of materials, permits, and interest on borrowing.

Capital investment in new resources - (see Capital costs)

Carrying capacity - The amount of energy that a Transmission facility can carry under specified conditions.

Cogeneration - The generation of power in conjunction with (usually) an industrial process, using waste heat from one process to fuel the other.

Common Forecasting Methodology VI (CFM VI) - Filings of projected loads, costs, and prices by California utilities to the California Energy Commission.

Composite retail rates - The average retail rates calculated for (1) all the publicly owned utilities and (2) all the investor-owned utilities in the Pacific Northwest.

Critical period average energy generation - The average amount of energy projected to be generated during a period (which can vary in length depending on the purpose of the planning) of extremely low streamflow. Used as a basis for resource planning.

Critical Rule Curve - A set of end-of-month reservoir contents which take the reservoir from full to empty during a critical period. Critical rule curves are used to guide reservoir operation during actual operation.

Crustaceans - Aquatic creatures such as barnacles and crabs, which have a segmented body, an exterior shell-like skeleton, and paired, jointed limbs.

Cubic feet per second (cfs) - A unit of measurement pertaining to flow of water. One cfs is equal to 449 gallons per minute.

Cultural resources - The nonrenewable evidence of human occupation or activity as seen in any district, site, building, structure, artifact, ruin, object, work of art, architecture, or natural feature that was important in human history at the national, state, or local level.

DC - (see Direct current)

DSI - (see Direct-service industries)

Dam passage - The percentage of fish which get from one side of a dam to the other alive.

Damage functions - Mathematical expressions based on scientific and socioeconomic observations which can be used to relate exposure to an environmental condition to an economic or social condition.

Declining block rate structure - In a rate schedule for a particular customer class, a structure that specifies lower kWh rates as consumption increases for specified ranges of usage.

Decremental cost - The cost that a utility could avoid by not operating a power plant; a utility's decremental cost is considered by some regulators to be a "fair" rate for the utility to pay for purchased power.

Deoxygenation - The depletion of dissolved oxygen in water.

Dewater - (a) To remove water from a solution containing wastes in order to concentrate and then dispose of the wastes. (b) To divert or remove water from a stream or river channel in order to construct or rebuild dams and related hydroelectric facilities.

Direct current (DC) - Term applied to an electric current or voltage which may have pulsating characteristics, but which does not reverse direction at regular intervals.

Direct-service industries (DSIs) - Industrial customers, primarily aluminum smelters, that buy power directly from BPA at relatively high voltages.

Dispatch - The monitoring and regulation of an electrical system to provide coordination; or the sequence by which electrical generating resources are called upon to generate power to serve changing amounts of load.

Displacement - The substitution of less-expensive energy (usually hydroelectric energy transmitted from the Pacific Northwest or Canada) for more expensive thermal energy produced in California. Such displacement means that the thermal plants may reduce or shut down their production, saving money and often reducing air pollution as well.

Dissolved gas concentrations - The amount of chemicals normally occurring as gases, such as nitrogen and oxygen, which are held in solution in water, expressed in units such as milligrams of the gas per liter of liquid.

Distribution costs - Costs faced by a utility that sells electricity at retail to consumers, the costs of transporting the power from the transmission substation to the consumer.

Double-circuit - The placing of two separate electrical circuits on the same row of towers. For alternating current, each circuit consists of three separate conductors or bundles of conductors.

Downstream Migrant Survival - The survival of an individual juvenile salmon or steelhead from the time it enters the mainstem Snake or Columbia Rivers, until it gets below Bonneville Dam.

Drawdown - The distance that the water surface of a reservoir is lowered from a given elevation as water is released from the reservoir (drafted).

Economic dispatch - Scheduling the operation (or, for the EIS, access to the Intertie) of power plants in the order of increasing monetary costs; that is, the least-expensive first.

Economy energy - Nonfirm energy that can be generated on a partially loaded generating unit, or purchases of energy, at a price less than decremental cost. Economy energy is unconditionally interruptible.

Electrostatic precipitators - Devices used to remove particulate air pollutants from an air stream by establishing an electric charge on the particles which then are attracted to an oppositely charged collector.

Emergence - Migration of hatched salmon fry up through the gravel of a redd preparatory to continuing their life cycle in open water.

Endangered - A plant or animal species which is in danger of extinction throughout all or a significant portion of its range because its habitat is threatened with destruction, drastic modification, or severe curtailment, or because of overexploitation, disease, predation, or other factors; federally endangered species are officially designated by the U.S. Fish and Wildlife Service and published in the Federal Register.

Energization - The point at which a completed energy facility is put into operation.

Energy Content Curve (ECC) - A set of end-of-month reservoir contents which assure a high probability of refilling the reservoirs.

Energy losses - The difference between power supplied and power received, due to dissipation by the transmission line or other facility.

Energy surplus - A condition in which a utility system can supply more energy than is demanded; the energy may be nonfirm, due to water conditions, or firm, due to excess generating capability.

Entrainment - The drawing of fish and other aquatic organisms into tubes or tunnels carrying water for cooling purposes into thermal plants or for generating purposes into hydroelectric plants. Entrainment increases mortality rates for those organisms.

Environmental dispatch - Scheduling the operation (or, for this EIS, access to the Intertie) of power plants in the order of increasing damage to the environment; that is, the most environmentally benign first.

Equilibrium values - For the projection of BC Hydro's retail power rates for the EIS, the rates that reflect an economic equilibrium of supply and demand, considering the cost to supply the power (less revenues from secondary sales) and the loads.

Estuary - A coastal inlet where salt water meets fresh water, as at a river's mouth.

Eutrophication - The increase of aquatic vegetation (at the expense of animal life) as more plant nutrients are supplied.

Exchange energy - Under a capacity/energy exchange contract, the energy that must be generated or purchased by a utility as compensation for capacity service that was provided by another utility.

Export sales - The sales of electricity from one region to another.

Exportable Agreement - A signed agreement (between BPA and numerous Pacific Northwest utilities) on procedures for sharing access on the Intertie when more water has been stored behind dams than can be used or when more power at the applicable rate is available than can be scheduled on the Intertie. No extraregional utilities or nonsignatories are afforded access. The Agreement, signed in 1969, is due to expire in 1989.

Exportable energy - Under the Exportable Agreement, the energy that the Pacific Northwest is unable to sell to California at the applicable rate.

Extraregional - Any entity or place not within the Pacific Northwest.

FCRPS - (see Federal Columbia River Power System)

FGD - (see Flue-gas desulfurization)

Federal Columbia River Power System (FCRPS) - The hydroelectric dams on the Columbia River financed by the U.S. Treasury, which operate as a coordinated generation system, and for which BPA serves as the power marketer.

Fingerlings - Young or small fish, especially very small salmon or trout.

Firm - In the power industry, guaranteed or assured. May refer to a guaranteed supply of power, to guaranteed access to a means to transmit power, or, with reference to loads, to guaranteed service for a defined need. Usually defined for a given period of time.

Firm displacement power - Under the Firm Displacement Power (FD-85) rate, power that BPA would sell to Pacific Northwest utilities to displace their planned resources, which would then be sold out of the region for at least 3 years.

Firm energy load carrying capability - The minimum level of energy that can be produced and shaped to load during the period it would take reservoirs to be drafted from full to empty under critical streamflow conditions.

Fish ladder - A series of ascending pools constructed to enable salmon or other fish to swim upstream around or over a dam.

Fish passage facilities - Features of a hydroelectric or other type of dam to enable fish to move around, through, or over them without harm.

Fish Spill Plan - A plan to provide a certain percentage of the total flow of a project as spill, for Federal and non-Federal projects.

Flaring - The practice of disposing of a waste combustible gas by burning it in a open flame without recovery of heat and, typically, at the top of a stack.

Flow rate - The volume of a fluid which passes a point in a defined channel per unit of time.

Flow regimes - The pattern of flow as it changes with time over the course of some specific time period.

Fluctuation zone - The area between the maximum and minimum water levels in a reservoir.

Flue-gas desulfurization (FGD) - The process of removing sulfur dioxide and other oxides of sulfur from gases generated by combustion or some other process before they are discharged to the atmosphere.

Fly-ash - Particulate matter remaining after combustion of a material which is entrained into the gas stream, and which may in large part be captured by an air pollution control device and, generally, disposed as a solid waste. Fly-ash not so captured is discharged as particulate matter into the atmosphere.

Foodweb - The interlocking pattern of food chains that results from their interconnection with one another; a way of presenting the flow of energy through an ecosystem.

Forced outage - The unexpected failure of some part of the power system to perform its function.

Forebay - The portion of the reservoir at a hydroelectric plant which is immediately upstream of the generating station.

Formula allocation - Conditions established by the NTIAP for allocating access to the Intertie, specified by formula.

Fossil fuel - A combustible, carbonaceous material formed from the remains of ancient plants and animals. Common fossil fuels include coal, natural gas, and derivatives of petroleum such as fuel oil and gasoline.

Functional capacity - The actual power carrying capability of a transmission line.

Fuel conversion efficiencies - The ratio (commonly expressed in percent) of the heating value of the fuel used per unit time to the power output of a generating plant.

Generic firm contract - A hypothetical regional firm power sale that converts to a capacity sale and capacity/energy exchange as the region's surplus firm energy disappears.

Geothermal (energy) - The heat energy available in the rocks, hot water, and steam in the earth's subsurface.

Groundwater - The supply of fresh water under the earth's surface in an aquifer or soil.

Guaranteed access - (see Assured access)

High/low export conditions - The range of availability of export power from the Pacific Northwest due to water conditions was analyzed to provide a background against which to see the effects of the various Intertie decisions: the high 10 percent, low 10 percent, and middle 80 percent of export availability conditions were grouped.

Hourly allocation (nonfirm) basis - The method for allocating access to the Intertie for short-term (hourly) transactions of nonfirm energy.

Hydraulic head - The vertical distance between the surface of the reservoir and the surface immediately downstream of the turbine and dam.

Hydraulic residence times - The average travel time for a particle of water through a reservoir or other body of water.

Hydro Block - The electrical energy available from the hydro system which is divided into various portions or "blocks," depending on conditions applied to its use.

Hydrocarbons - Chemical compounds containing hydrogen and carbon. Some hydrocarbons may become air pollutants. Some hydrocarbon air pollutants are carcinogenic, and some react with other air pollutants to form photochemical smog.

Hydroelectric - With reference to a power system, the production of electric power through use of the gravitational force of falling water.

Hydrology - The localized conditions relating to the occurrence, circulation, distribution, and properties of ground and surface waters.

Hydrostatic testing - The use of pressurized water to test a tank, pipeline, or other equipment for leaks.

IOU - (see Investor-owned utilities)

ISW - (see Inland Southwest)

Impoundment - The accumulation of water in a reservoir.

Incubation - The period between fertilization of an egg and its hatching.

Inland Southwest (ISW) - For the purposes of this EIS, the States of Nevada, Arizona, Colorado, Utah, and New Mexico.

Instantaneous flow rate - The minimum amount of flow required (usually in terms of fish survival and functioning) at a given moment in time.

Interruptibility - The extent to which the flow of power can be stopped for a given period of time. By agreement, the supply of interruptible power can be shut off to a customer on relatively short (hours or a few days') notice.

Intertie Access - The assigned right to send a defined amount of electric power at a certain time over the high-voltage line system called the Pacific Northwest-Pacific Southwest Intertie.

Inundation - The flooding or covering up of an area with water. Inundation occurs when a reservoir is first filled.

Investor-owned utilities (IOU's) - Privately owned utilities whose programs are financed by private (nongovernment) investors in the utility's stocks and bonds. (In contrast to publicly owned utilities.)

Juvenile - The stage in the life cycle of anadromous fish when they migrate downstream to the ocean.

kcfs - One thousand cubic feet per second. A measure of speed and volume of water flow. (see Cubic feet per second)

Kilowatthour (kWh) - The common unit of electric energy equal to 1 kilowatt of power supplied to or taken from an electric circuit for 1 hour. A kilowatt equals 1,000 watts.

LCMM - (see Least Cost Mix Linear Program Model)

LP - (see Marketing Linear Program Model)

LTIAP - (see Long Term Intertie Access Policy)

Laissez-faire - A hypothetical hands-off policy of Intertie access that would allow the Intertie to be used on a first-come, first-served basis; no restrictions would be imposed on access to the Intertie for new resources.

Larvae - The newly hatched, earliest stage of anadromous fish.

Lead Federal agency - The Federal agency charged with primary responsibility for evaluating in conformance with the National Environmental Policy Act the potential environmental effects of a project involving Federal action.

Leakage - An amount of water which leaks around a dam without passing through the turbines, spillway gates, or navigation locks.

Lockage - An amount of water which passes through the navigation locks and does not pass through the spillway gates or turbines of a dam.

Least Cost Mix Linear Program Model (LCMM) - A linear program computer model that estimates the amount of regional generation and conservation resources that should be acquired to yield a least-cost resource mix to meet a given firm load over a 20-year planning horizon.

Least cost mix of resources - The combination of generating (including conservation) resources that would meet a given amount of load at a given time or for a given period most economically.

Leveed islands - An area of land completely surrounded by water protected from flooding during high water by levees, embankments of earth rimming the island.

Levelized - Of costs, a method of calculating equal, periodic payments or receipts from unequal cost data for the same time period, considering the time value of money.

Linear regression analysis - The derivation of a mathematical relationship between dependent and independent variables based on a random sample of observations.

Littoral zone - The shallower waters near the shore of a reservoir or lake.

Load - The amount of electric power or energy delivered or required at any specified point or points on a system. Load originates primarily at the energy-consuming equipment of the customers.

Load growth - Increase in demand for electricity.

Load management - Influencing the level and shape of the demand for electrical energy so that it matches resources available as well as long-run objectives and constraints.

Load profiles - Information on the shape of customers' demands for electricity over time.

Load/resource balance - The point at which the demand for electricity matches or balances the amount and type of resources available to serve that demand.

Long Term IAP - (see Long Term Intertie Access Policy)

Long Term Intertie Access Policy (LTIAP) - The policy being developed by BPA to allocate use of the Federal portion of the Intertie for the long term, an indefinite period that would at least encompass long-term power sales (up to 20 years) and long-term transmission contracts.

Long-term transmission contracts - Contracts between BPA and other entities for the use of the Federal transmission system, including the Intertie, for 20 years.

Loopflow - The unscheduled flow of power across a transmission path. It occurs because power flows in accordance with the resistance (impedance) of the transmission paths in an interconnected power system. At times, loopflow can be strong enough to causes equipment overloads on a transmission path, so that power schedules must be reduced.

Low water years - Years in which less water than usual is received in a river system producing power from water flow. This is usually a consequence of reduced rain/snow fall over the fall and winter months.

MW - (see Megawatts)

Macroinvertebrates - Nonmicroscopic animals without a spine.

Marginal energy costs - For a generating resource, the cost to produce one more kilowatthour of electricity.

Marketing Linear Program Model (LP) - A linear program computer model that calculates decremental cost for each utility in the Southwest.

Megawatts (MW) - A megawatt is one million watts, an electrical unit of power.

Microclimate - The climate of a small area, as of houses, of plant communities, or of urban communities.

Mine-mouth - Used to refer to thermal generating plants located close enough to the fuel source (generally coal) that no long-distance fuel transport is necessary.

Minimum generation constraints - For thermal power plants, the minimum level of operation that must be maintained to keep the plant ready to generate power when needed.

Monthly sale shape - While sales of electricity are generally made in the amount of a yearly or seasonal average, demand for electricity can vary month-to-month. Thus, some contracts allow sales to be shaped to conform to monthly demand.

NTIAP - (see Near Term Intertie Access Policy)

Near Term - In general, the immediate future--a period of time usually less than 3 years.

Near Term Intertie Access Policy (NTIAP) - A policy BPA developed to allocate use of the Federal portion of the Intertie while the LTIAP is being developed; the NTIAP was put into effect in September 1984 to address immediate issues of Intertie access.

Nitrogen supersaturation - A condition of water in which the concentration of dissolved nitrogen exceeds the saturation level of the water. Excess nitrogen can lead to bubbles of nitrogen in the circulatory systems of fish.

Nominal dollars - For economic analysis, dollars in the year specified, not adjusted for the effects of inflation or the time value of money.

Nonfirm energy sales - Sales of electricity that are not guaranteed, but are interruptible under specified conditions.

Nonfirm access - Use of the Intertie to transport sales of nonfirm energy.

Nonfirm allocation procedure - The method to allocate use of the Intertie on an hourly basis for sales other than long-term firm power sales.

Nonfirm energy - Energy available due to water conditions better than critical, sold on an interruptible (nonguaranteed) basis.

Null hypothesis - A statistical hypothesis to be tested and accepted or rejected in favor of an alternative; specifically, the hypothesis that an observed difference is due to chance alone and not due to a systematic cause.

Nutrient loading - The quantity of elements or compounds essential as raw materials for organism growth and development which are dissolved or suspended in a sample of water.

Offpeak hours - Period of relatively low system demand for electrical energy, as specified by the supplier (such as the middle of the night).

Operating year - The 12-month period from September 1 through August 31.

Outplantings - Fish hatched and initially reared in a hatchery, which are then planted into natural habitats to continue juvenile rearing.

Overburden - The topmost layers of soil. In this EIS, the 30-50' layers of soil stripped off to reveal coal seams in the process of strip mining.

PCB's - (see Polychlorinated biphenyls)

PF rate - (see Priority Firm rate)

PNW - (see Pacific Northwest)

PSD - (see Prevention of Significant Deterioration increments)

PURPA - (see Public Utilities Regulatory Policy Act)

Pacific Northwest (PNW) - For this EIS, the States of Washington, Oregon, and Idaho; the portion of Montana west of the Continental Divide; and areas in Montana, Nevada, and Wyoming surrounding coal plants that serve the PNW.

Pacific Northwest Electric Power Planning and Conservation Act - Signed into law December 5, 1980, the Act provides for coordinated planning of the Pacific Northwest's energy future, through a Regional Planning Council with representation from Oregon, Idaho, Montana, and Washington.

Pacific Northwest Power Act - (see Pacific Northwest Electric Power Planning and Conservation Act)

Paired t-test - A statistical comparison between two sets of data used to determine to what extent they are dissimilar.

Passage survival - The survival rate of migratory fish through, around, or over dams or other obstructions in a stream or river.

Peak loads - The maximum electrical demand in a stated period of time. It may be the maximum instantaneous load or the maximum average load within a designated interval of the stated period of time.

Percolation - The movement of water through the subsurface soil layers, usually continuing downward to the groundwater and water table reserves.

Photochemical smog - A type of air pollution resulting when sunlight induces chemical reactions of other pollutants, notably nitrogen dioxide and hydrocarbons. Elevated ozone levels are an indicator of photochemical smog since ozone is one of the products of the photochemical reaction.

Phytoplankton - The plant portion of the floating or weakly swimming organisms, often microscopic in size, in a body of water.

Plume - The discharge of gas and other pollutants into ambient air, or the discharge of polluted or heated water into a body of water from its source to the point where the discharge is no longer identifiable since it has mixed with the ambient air or the water.

Plunging flows - Water flow over a very steep surface or off of a precipice into a pool. This situation is one which produces high levels of dissolved gases in the water, such as nitrogen supersaturation.

Polychlorinated biphenyls (PCB's) - A group of non-combustible synthetic insulating/dielectric fluids used in certain electrical equipment; found to be very persistent in the environment and strongly suspected of having carcinogenic effects.

Pool Mortality - Death that occurs to a juvenile salmon or steelhead as it migrates through the pool or reservoir of a run-of-the river project.

Power broker - A central power scheduling utility that matches lowest cost power offers in the Pacific Northwest with the highest offers to buy in the Southwest.

Power pool - A power pool is two or more electric systems interconnected and coordinated to supply power in the most economical manner for their combined load requirements and maintenance program.

Pre-emergent fry - Fish after they have hatched from their eggs but before they have left their incubation environment.

Predation - The capturing of prey as a means of maintaining life.

Preference customers - Cooperatives and public bodies (states, public utility district, counties, and municipalities, in the Northwest which have been given preferential rights by Congress to Federally generated hydroelectric power.

Prevention of significant deterioration (PSD) increment - Any one of several incremental changes in ambient total suspended particulate or sulfur dioxide concentrations established by the Environmental Protection Agency to protect existing air quality from being degraded significantly through new developments, such as construction and operation of a new air pollution source.

Priority Firm (PF) rate - The priority firm (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 Pacific Northwest Power Act.

Project outflow - The volume of water per unit of time downstream from a project.

Public Utilities Regulatory Policy Act (PURPA) - Enacted in 1978, it is the Federal legislation that requires utilities to purchase electricity from qualified independent power producers at a price that reflects what the utilities would otherwise have to pay for the construction of new generating resources.

Pumped Storage - An arrangement whereby electric power may be generated during peak load periods by hydroelectric plants using water previously pumped into a storage reservoir during offpeak periods.

Qualifying Facilities (QF's) - Renewable and cogeneration resources developed under the Public Utilities Regulatory Policy Act of 1978.

Real cost escalations - The increase in cost over a period of time due solely to the time value of money; that is, adjusted for price inflation.

Real discount rate - The factor used to compute the present value of a future amount, which adjusts solely for the time value of money and does not include price inflation.

Reclamation - The restoration of land to resemble its original condition or an acceptable substitute as to shape, vegetation, and wildlife; reclamation takes place after an area has been stripmined or after an energy facility has been built.

Record of Decision - The document notifying the public of a decision taken on a power project, together with the reasons for the choices entering into that decision. The Record of Decision is published in the Federal Register.

Recordation - The making of appropriate records (following National Park Service guidelines) to insure that a permanent record of a cultural resource's present appearance and context are made before the resource is disturbed through destruction, demolition, or inundation. Such a record might consist of written description, photographs, and so on.

Redds - Gravel nest created by female salmon or trout where its eggs are laid, subsequently hatched, and fry emerge.

Regional - Referring to the characteristics of an area, as opposed to those of a surrounding or adjacent area. Generally used in this EIS to distinguish between the Pacific Northwest and Canada or California or the Inland Southwest. (see Extraregional)

Relative - Considered in relation to a base case condition; comparative; not absolute or independent (opposed to absolute).

Relative change in survival - The difference in survival between the two alternatives divided by the base case survival value. The change in survival in relation to the base case survival.

Reliability level - For a power system, a measure of the degree of certainty that the system will continue operation for a specified period of time.

Relic collecting - The seeking out and removal of artifacts or other cultural resources by private persons. The practice consequently excludes opportunities for study or preservation of the site, and often results in destruction of artifacts, the site itself, and/or nearby sites.

Renewable resources - Resources for energy which are continually replenished. Water, for instance, is a renewable resource, while coal which is converted into carbon dioxide, water, and ash when burned is not.

Replication - A copy or reproduction of a cultural artifact. Replication is most often done for rock art or engravings, by making a mold or cast of the work.

Reserve margins - For a power plant or transmission facility, extra capacity above the amount projected to be needed, to allow for unanticipated demand for power, equipment failure, or other unforeseen events.

Reservoir draft rate - The rate at which water, released from storage behind a dam, reduces the pool elevation of the reservoir.

Reservoir elevations - The various levels reached by water stored behind a dam.

Resident fish - Fish species which reside in fresh water during their entire life cycle.

Residential Exchange Program - An exchange of power prescribed by section 5(c) of the Pacific Northwest Power Act. Pacific Northwest utilities sell BPA an amount of power equal to their residential and small farm load, in exchange for less-expensive Federal electricity. The cost benefits are directly passed on by the utilities to their residential and small farm consumers, in the form of lower retail rates to those customers.

Residual fuel oil - Fuel oil that remains after separation of valuable distillates (such as gasoline) from petroleum through distillation.

Resource dispatch - For this EIS, the order of access or the monitoring of power resources for access to the Intertie.

Resource mix - The different types of resources used to generate power (e.g., hydroelectric, thermal, etc.) within a given area or for a given utility.

Resource schedule - The planned schedule of when and what resources will be available in the future to serve load in a given area or of a given utility.

Retrofit - To weatherize an existing structure.

Return energy - The energy that is returned to the Pacific Northwest, equalling the amount of energy previously sent south, under the terms of the capacity sales and capacity energy contracts.

Riprap - Broken rock, cobbles, or boulders placed on the bank of a stream or river for protection against the erosive action of water.

Run-of-river plant - A hydroelectric plant with little or no ability to regulate flow.

Run-of-the-River Dams - Hydroelectric generating plants that operate based only on available streamflow and some short-term storage (hourly, daily, or weekly).

Running costs - Also called variable costs--the costs that are incurred or are increased when a power plant operates.

Salmonids - Fish belonging to the family of salmonidae, including salmon, trout char, whitefish, and allied freshwater and anadromous fish.

Scheduling Utilities - Pacific Northwest scheduling utilities include Bonneville Power Administration, Seattle City Light, Tacoma City Light, Grant County PUD, Douglas County PUD, Chelan County PUD, Pend Oreille PUD, Eugene Water and Electric Board, Cowlitz County PUD, Snohomish County PUD, Montana Power Company, Idaho Power Company, Pacific Power & Light Company, Portland General Electric Company, Puget Sound Power & Light and Washington Water Power Company. Utilities that either operate a generation control area or are within BPA's control area that schedule with BPA.

Scoping - The definition of the range of issues requiring examination in studying the environmental effects of a proposed action. Scoping generally takes place through public consultation with interested individuals and groups, as well as with agencies with jurisdictions over parts of the project area or resources in that area. Scoping is mandated by the Council on Environmental Quality regulations.

Secondary power - The excess above firm power to be furnished to a customer when, as, and if available.

Secondary revenues - Revenues received from sales of secondary energy, which is the energy produced in excess of firm power due to favorable water conditions.

Secondary sales - Surplus power, both firm and nonfirm, in the Pacific Northwest that is available for sale to the Pacific Southwest.

Sedimentation - The settling of material (such as dust or other particles) into water and eventual deposition on the bottoms of streams, rivers, and so on.

Settling ponds - A pond into which water containing suspended solid material is discharged to allow the solid material to separate from the water by gravity.

Shaping - The scheduling and operation of generating resources to meet load of changing levels. Load shaping on a hydro system usually involves the adjustment of storage releases so that generation and load are continuously in balance.

Short-run marginal cost - The cost per unit of buying (or the amount saved by not buying) or producing a specified amount of a product in the near future.

Short-term sales - Sales made for a relatively short period of time.

Simulation - The representation of an actual system by analogous characteristics of some device easier to construct, modify, or understand, or by mathematical equations.

Slag - In the context of this EIS, molten or solidified ash formed from noncombustible material in a fuel by chemical action and fusion at boiler operating temperatures.

Sludge - The wet, solid or semisolid material formed when particulate air pollutants and/or sulfur dioxide is removed by a wet scrubber air pollution control device.

Slurry pipeline - A means of coal transport in which the coal is finely ground, mixed with water, and run through a pipeline to its destination, where it is dewatered and combusted.

Small hydro - Generating resources which use running water to generate electric energy, but which are small in generating capacity. BPA generally considers small hydro projects to be those capable of producing 25 average MW or less.

Smolt - A juvenile salmon or steelhead that is migrating to the ocean and is in a physiological state to transition from fresh to salt water.

Snowmelt freshet - Increased streamflow from the melting of accumulated snowfall.

Spawning - The act of fish releasing and fertilizing eggs.

Spill (forced) - Water for which there is not storage capability in the system reservoirs and which could not be used for power production because the resulting flows would exceed turbine capacity.

Spill (inadvertent/overgeneration) - An amount of water which could have been used to generate electricity but was not because of lack of available market, and inability to store for later use.

Spill (programmed or planned) - Water intentionally passed through a hydroelectric project without producing electricity. This is usually done for fisheries mitigation proposes.

Spoil piles - Heaps of soil and other material removed during surface mining, and later used to reclaim the site.

Sport fish - Fish which are sought by recreational fishermen.

Spot market - A market for electricity characterized by negotiation almost solely on the basis of price, for relatively short-term sales.

Storage reservoirs - Reservoirs maintained behind dams for the purpose of retaining excess water readily available during springtime flows as snow melts. Retained water is then released, as necessary, during periods of lower flow in order to maintain necessary levels of power production. (Water may also be released for other purposes, such as navigation, irrigation, and maintenance of life support for fish.)

Storage rights - Rights provided to BPA for use of storage in Canadian reservoirs.

Stratification (chemical) - The separation into layers differentiated by chemical composition.

Stratification (thermal) - The separation into layers differentiated by temperature.

Subalpine - A terrestrial zone of high upland slopes, immediately below the timberline, characterized by conifer forest consisting of spruce and fir.

Subscription - A proposed offer to Pacific Northwest generating utilities that after completion of the Third AC project would allow them to buy a portion of 800 MW of uprated Intertie.

Subyearling - A juvenile salmonid, normally a fall or summer chinook salmon, that hatches and migrates to the ocean in the same year.

Surplus capacity - The amount of excess Intertie capacity available after reserving sufficient capacity for sale of BPA surplus firm and nonfirm energy.

Surplus energy - Generally energy generated that is beyond the immediate needs of the producing system. Specifically for BPA, firm or nonfirm electric energy generated at Federal hydroelectric projects which would otherwise be wasted if there was not a market for the energy.

Surplus firm energy - Energy that can be generated and guaranteed to be provided, but is excess to demand.

Surplus firm power - Power that can be provided on a guaranteed basis, that is excess to system demand, and that can be provided in an agreed upon shape.

Surplus nonfirm energy - An excess of interruptible energy that is available due to water conditions better than critical.

Surplus peaking capacity - Electric peaking capacity for which there is no demand in the Pacific Northwest at the rate established for the disposition of such capacity.

System Refill - The coordinated hydro system is considered full, for the purposes of the IDU EIS modeling, when the amount of water stored in reservoirs is equal to 94 percent of the total available space.

System Stock Survival - The survival of migrating juvenile salmon or steelhead of a particular fish stock from the point of entry into the hydroelectric system to a point below Bonneville Dam.

TSP - (see Total suspended particulates)

Tailwater - The water surface immediately downstream from a dam or hydroelectric powerplant.

Thermal resources - Generating plants which convert heat energy into electric energy. Coal, oil, and gas-fired power plants and nuclear power plants are common thermal resources.

Thermal Structure - Reservoirs stratify into three layers in summer months: light warmer water on surface, a thermocline of cooler water, and a layer of cold oxygen deficient water on bottom. Rapid drawdowns cause this stratification to breakdown, reducing production of food organisms, and cooling water temperatures.

Thermally enhanced oil recovery - A process by which heavy crude petroleum underground is subjected to live steam, which reduces the oil's viscosity so it can flow up the pipe to the surface. Steam from the process can be used to cogenerate energy, which can be sold to utilities pursuant to PURPA. Thermally enhanced oil recovery is being used in California's San Joaquin Valley.

Tiered pricing - In California, the practice of setting two prices for sale of natural gas to electric utilities; one price for smaller purchases, a lower price for larger purchases.

Total suspended particulates (TSP) - An air pollution term referring to all matter contained in a sample of air which is in solid or liquid form regardless of its particle size or chemical composition.

Trace elements - Pollutants, often metals in ionic or chemically combined form, which appear in very small concentrations in water, or in reference to air pollution, which constitute a very small part of the total amount of particulate pollution by weight.

Transfer capability - The amount of power that can be transmitted between one interconnected system and another, based on installed facilities.

Transfer capacity - (see Transfer capability)

Transmission grid - An interconnected system of electrical transmission lines and associated equipment for the transfer of electric energy in bulk between points of supply and points of demand.

Transmission losses - Power lost in transmission between one point and another.

Turbidity - A measure of the optical clarity of water, which depends on the light scattering and absorption characteristics of both suspended and dissolved material in the water.

Turbine Capacity - The maximum amount of water that can be passed through the turbines of the dam at any instant.

Upgrades - Increases to the physical capacity of the existing Pacific Northwest-Pacific Southwest Intertie to 7900 MW.

Utility retail rates - The prices for electricity that a utility charges its classes of consumers.

Variable ECC - The January through July portion of the ECC. It is based on expected amount of spring runoff with available forecasts. The variable can be no higher than the Base ECC.

Venting - The release of limited amounts of gases or vapors to maintain pressures within tanks, pipes, and other equipment involved in oil and natural gas processing and transportation within design limits.

Water Budget - A part of the Pacific Northwest Power Planning Council's Fish and Wildlife Program calling for a volume of water to be reserved on a planning basis and released when and if needed to augment stream flows in order to assist in the downstream migration of juvenile salmon and steelhead.

Water conditions - The overall supply of water to operate the Pacific Northwest hydroelectric generating system at any given time, taking into account reservoir levels, snowpack, needs to provide water or retain water to meet various operating constraints (such as the Water Budget, flood control, flow constraints, etc.), weather conditions, and other factors.

Wholesale rates - The prices for electricity that a utility charges for power that will be resold. In BPA's case, BPA also charges wholesale rates to its DSI customers because they buy at relatively high voltage.

Yearlings - Juvenile salmon and steelhead that migrate to the ocean, often spending a full year rearing in fresh water.

Zooplankton - Aquatic animals which cannot actively swim against the current and which cannot make their own food by photosynthesis.

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Chapter 10

I N D E X

The following items identify where major references or discussions are located. For chapter, section, and subsection headings, see the Table of Contents.

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