ADMINISTRATOR'S DECISION

LONG-TERM INTERTIE ACCESS POLICY

U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
MAY 17, 1988

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Abbreviations Used in Decision

LIST OF COMMENTERS

Anglers	Southwest Washington Anglers
APAC	Association of Public Agency Customers
Basin	Basin Electric Power Coop
BC Hydro	British Columbia Hydro and Power Authority
Benton Coop	Benton Rural Electric Assn
Benton PUD	Benton County PUD #1
Big Bend	Big Bend Electric Coop
BLM	Bureau of Land Management
BPA	Bonneville Power Administration
Canby	Canby Utility Board
CEC	California Energy Commission
Chelan	Chelan County PUD #1
Clark	Clark County PUD
COE	U.S. Army Corps of Engineers
Cowlitz	Cowlitz County PUD
CPUC	California Public Utilities Commission
CRITFC	Columbia River Intertribal Fish Commission
DSI	Direct Service Industries
EWEB	Eugene Water and Electric Board
Ferry	Ferry County PUD #1
Flyfishers	Clark-Skamania Flyfishers
Grant	Grant County PUD #2
Harney	Harney Electric Coop
ICP	InterCompany Pool
IPUC	Idaho Public Utilities Commission
IPC	Idaho Power Company
LADWP	Los Angeles Department of Water and Power
Mason	Mason County PUD #3
Mid-Columbia	Mid-Columbia PUD
MPC	Montana Power Company
NCAC	National Conservation Act Coalition
NCPA	Northern California Power Agency
NGPU	Non-Generating Public Utilities
NIU	Northwest Irrigation Utilities
NMFS	National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NRDC	National Resources Defense Council
NWPPC	Northwest Power Planning Council
OPUC	Oregon Public Utilities Commission
ORECA	Oregon Rural Electric Cooperative Association
PG&E	Pacific Gas & Electric Company
PGE	Portland General Electric Company
PGP	Public Generating Pool
PNGC	Pacific Northwest Generating Company
PNUCC	Pacific Northwest Utilities Conference Committee
Port Angeles	Port Angeles City Light

PP&L	Pacific Power & Light Company
PPC	Public Power Council
PSP&L	Puget Sound Power & Light Company
Ravalli	Ravalli County Electric Coop
SCE	Southern California Edison Company
SCL	Seattle City Light
SDG&E	San Diego Gas & Electric
Sierra	Sierra Club
Skagit	Skagit System Cooperative
SMUD	Sacramento Municipal Utility District
TANC	Transmission Agency of Northern California
TCL	Tacoma City Light
Tillamook	Tillamook County PUD
Umatilla	Umatilla Electric Coop
UP&L	Utah Power & Light Company
Vernon	City of Vernon, CA
Vigilante	Vigilante Electric Coop
WAPA	Western Area Power Administration
Wasco	Northern Wasco County PUD
WPAG	Western Public Agencies Group
WPSC	Wyoming Public Service Commission
WUTC	Washington Utilities and Transportation Commission
WWP	Washington Water Power Company

OTHER ABBREVIATIONS

AC - alternating current
aMW - average megawatts
ASC - Average System Cost
BPA - Bonneville Power Administration
COTP - California-Oregon Transmission Project
CT - combustion turbine
DC - direct current
DOE - Department of Energy
DSI - direct-service industrial customer
EIS - environmental impact statement
FCRPS - Federal Columbia River Power System
FERC - Federal Energy Regulatory Commission
FY - fiscal year
IAP - Intertie Access Policy
IDU EIS - Intertie Development and Use Environmental Impact Statement
IOU - investor-owned utility
kV - kilovolt (one thousand volts)
kWh - kilowatthour (one thousand watthours)
LTIAP - Long-Term Intertie Access Policy
MW - megawatt (one thousand kilowatts)
NEPA - National Environmental Policy Act
NTIAP - Near-Term Intertie Access Policy
O&M - operations and maintenance
OY - operating year
PF - priority firm power (rate)
PNW - Pacific Northwest
PURPA - Public Utility Regulatory Policies Act
WNP - Washington Public Power Supply System Nuclear Project

This decision on the Long-Term Intertie Access Policy (LTIAP or policy) is divided into five parts. Part One is an Introduction, covering important background information on the Intertie and our access policies. Part Two resolves issues regarding "Formula Allocation" provisions for short-term energy transactions utilizing the Pacific Northwest-Pacific Southwest Intertie. Part Three analyzes issues on "Assured Delivery" of long-term firm power transactions. Part Four discusses issues related to the IAP's fish and wildlife provisions. Part Five sums up the entire decision by analyzing the effects of the LTIAP on each group interested in the outcome of our decisions on Intertie access.

Issues each are discussed in three steps. First, we explain our proposal in the 1987 draft LTIAP. Second, we summarize the comments received in the public comment process. Third, we discuss the points raised in comments and explain our decision.

The citations to the record of this proceeding are of two forms. Written comments are cited using the form: commenter, record citation, and comment page number. Citations to the transcript appear as "Tr. __."

PART ONE

INTRODUCTION

Section 1. Operation Of The Intertie

The Facility. Since its completion in 1968, the Intertie has served as the principal means for transmitting surplus capacity and firm power and nonfirm energy between the Pacific Northwest and California. This section briefly describes the Pacific Northwest-Pacific Southwest Intertie and gives a picture of the complex nature of its operation.

Legislation authorizing construction of an Intertie system focuses on two objectives. [1/]

First, Congress sought to provide an additional market for BPA power, enabling us to increase revenues and repay the U.S. Treasury in a timely manner. BPA owes the Treasury $8 billion associated with capital investments in the Federal Columbia River power generation and transmission systems. By transmitting surplus power and energy to California, we can obtain additional revenue to repay the Treasury in a timely manner.

Second, the Intertie makes more efficient use of resources in the Northwest and California. When the Northwest has surplus power during summer months, power generally can be sold to California more cheaply than California utilities can operate their thermal generation plants. When the Northwest has "peak" needs in winter for heating and California loads are lower, the Northwest can purchase power from California. Existing resources can be used more efficiently, and both regions can avoid building generation to meet peak loads at some times of the year.

1/ 16 U.S.C. §837 (Northwest Preference Act) (1964). See also Department of Water and Power v. BPA, 759 F.2d 684 (9th Cir. 1985).

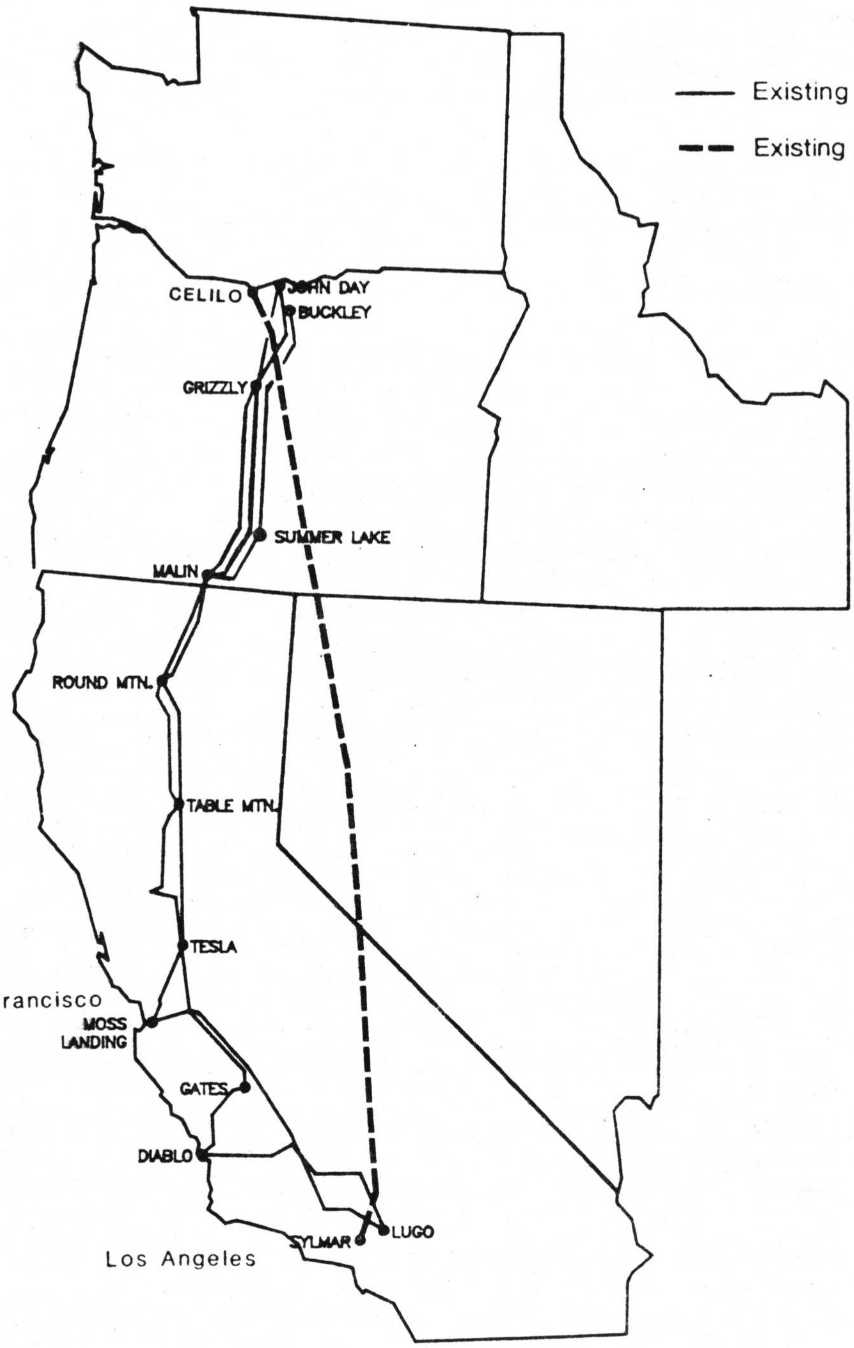
In the Northwest, the Intertie consists of several high-voltage transmission lines -- two 500-kilovolt (kV) alternating-current (AC) lines, a portion of a third 500-kV AC line, and one 1,000-kV direct-current (DC) line (see Figure 1). The AC lines extend about 945 miles from John Day Substation near 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 DC line runs from the Celilo Station near The Dalles Dam, Oregon, to the Sylmar Station near Los Angeles. The DC line transmits power between the Northwest and Southern California.

The present physical capability of the Intertie lines is approximately 5,200 MW -- about 3,200 MW on the AC lines and 2,000 MW on the DC line. The terminals at both ends of the DC line are currently being upgraded, which will increase the line's capacity by approximately 1,100 MW. There are also plans to increase the capability of the AC lines to approximately 4,800 MW. In the Northwest, the facilities of the AC Intertie are individually and jointly owned by BPA, PGE, and PP&L. BPA owns or controls nearly 80 percent of the Intertie capacity north of the Oregon border. BPA shares its Intertie capacity with nonfederal utilities for both spot-market and long-term transactions.

Discussing the northern portion of the Intertie tells only half the story. California utilities constructed AC and DC lines to meet the lines constructed in the Northwest. Capacity on the southern portion matches that of the northern portion. Four utilities -- PG&E, SCE, LADWP, and SDG&E -- own approximately 80 percent of the Intertie capacity south of the Oregon border.

The Operation. It is important to distinguish between two distinct levels of operation to understand the complex and integrated nature of the Intertie system.

Existing Intertie System



The first level is the daily operation of the Intertie. The three northern owners and all other utilities using the Intertie must coordinate and cooperate in the operation of the Intertie. The northern portion of the Intertie connects with two other utility service territories. The Intertie can receive and dispatch energy at each of these interconnections for sales over the facility.

In the north, we serve as the central scheduler for transactions and deliveries of energy. In the south, PG&E is the scheduler for the AC line and SCE is the scheduler for the DC line. All utilities who use the Intertie are in close communication with the schedulers. A single spot-market sale requires two utilities to agree in advance on quantity, price, and timing; to arrange with the schedulers in advance of the delivery; and then to deliver and receive the energy at the appointed time. Frequently these scheduled deliveries change on a "real-time" basis due to changes in a utility's system operations. As scheduler for the northern portion of the Intertie, we employ people around the clock to coordinate these activities.

The Intertie serves a variety of markets. Energy may flow in either direction depending on the conditions of supply and demand. Utilities purchase energy both on the spot market for short periods of time and on a long-term basis. Utilities exchange energy on a daily, weekly, monthly, or seasonal basis. For instance, a Southwest utility may receive Northwest energy in the summer to meet its peak cooling load and return it to a Northwest utility in the winter to meet its peak heating load. The Northwest with its large hydroelectric and storage capability is well equipped to meet the peaking capacity requirements of California. With this type of transaction a California utility purchases the right to demand energy over the Intertie if it needs it. In critically low water years, Northwest utilities can rely on Southwest utilities for similar needs.

The second level of operation is contractual. The existing rights to the Intertie are based on ownership of facilities. On the northern portion, BPA owns the DC Intertie and the majority of facilities in the two AC lines. PGE owns a segment of the existing two-line AC Intertie and has contractual rights to 25 percent of the capacity produced by those two lines. Our agreement with PGE expires this year; BPA and PGE are currently negotiating a replacement agreement.

PP&L and BPA have executed an agreement that provides PP&L a firm right to 300 MW of capacity for delivery to California at the Malin substation. This right will increase if the AC systen is upgraded. We received the right to utilize PP&L's facilities for Intertie deliveries and the right to participate with PP&L in construction of a 500-kV line from Alvey substation to Meridian substation, if we determine that would be the best plan-of-service for increasing capacity in the Northwest to accommodate the California-Oregon Transmission Project for upgrading AC Intertie capability in California. BPA's agreement with PP&L expires in 2016. In addition, we have a number of agreements with PGE and PP&L addressing construction and operation and maintenance of Intertie facilities.

Construction of the third AC line in the Northwest would add another layer of contract and ownership rights to the Intertie system, as would nonfederal participation in the third AC project.

We have agreements with other Northwest utilities for use of BPA's capacity on the Intertie and one agreement with an extraregional utility, Basin Electric Cooperative in North Dakota. These agreements consist of long-term contracts for wheeling over the Federal portion of the Intertie. Prevalence of this type of contract will increase with adoption of the LTIAP.

Competing Demands. The Intertie is a resource that generates hundreds of millions of dollars per year of revenues and that eliminates the need for new resources, particularly in the Southwest. Generating utilities in the Northwest and California have access for firm and spot-market sales. It is not surprising that these utilities compete for access rights to this limited resource.

If the only demand on Intertie use came from utilities with surplus power to sell, the answers to the issues involved in developing a reasonable access policy might be more clear. However, other groups have placed demands on how and for what purpose the Intertie is used. One group is BPA's full requirements customers, which include nongenerating public utilities and direct-service industrial customers, primarily aluminum smelters. They have consistently demanded a policy that would allow BPA to use the Intertie in such a manner as to maximize BPA revenues from sales of BPA's surplus power.

Environmental groups and fish and wildlife organizations also have stated their preference for how the Intertie should be used. They have focused on implementing a policy which would have no adverse impact on fish and wildlife resources in the Northwest. Environmentalists support a policy which would prevent hydro development on rivers and streams in the Northwest, no matter how economically rewarding for developers.

California utilities seek a policy which provides the maximum amount of Northwest energy at the lowest cost. They would like to rely on inexpensive, abundant Northwest energy to meet their future load growth by means of either firm purchases or exchanges.

Finally, BPA has demands of its own, based on the objectives specified in the enabling legislation for construction of the Intertie. The LTIAP must be structured to assist us in repaying the $8 billion Treasury investment in the Federal power and transmission systems. Furthermore, we do not want to encourage hydro development that could jeopardize our $120 million investment in fish and wildlife protection.

Section 2. Evolution Of The Intertie Access Policy

Interim IAP. Before adopting an Intertie access policy, we were often unable to make the sales we wished due to the requirements of the Northwest Regional Preference Act, 16 U.S.C. §837, et seq. Under this law we must announce our price to Northwest utilities prior to selling energy out of the region, which allows those utilities, our competitors, to underbid our price when they make sales to California.

This situation was exacerbated by the restricted market in California, where there are relatively few buyers because owership of the Intertie is limited. Consequently, insufficient competition has existed on the southern end to balance the downward pressure on prices in the Northwest. As we lost sales, our reservoirs would rise, hastening the time when we would have to implement the Exportable Agreement (including the very low prices which at that time were tied to the Agreement). Although we were assured of sales under the Exportable Agreement, the prices we obtained were much lower than we otherwise would have received.

The unexpected power surplus in the Northwest and Canada that materialized in the early 1980s caused us to review our use of the Federal share of the Intertie. BPA, as well as many of the generating utilities in the Northwest, suddenly had a large firm power surplus. This was also the case for British Columbia Hydro and Power Authority (BC Hydro) and utilities as far away as North Dakota. All were hoping to sell their surplus in the Southwest over available Federal Intertie capacity.

At the same time, BPA finances took a downturn due to (1) costs imposed by the Northwest Power Act for conservation, fish and wildlife, the residential exchange subsidy program, and other Congressional goals; (2) decisions relating to the Washington Public Power Supply System nuclear plants;

(3) direct-service industrial customer (DSI) aluminum plant shutdowns and closures; and (4) an economic recession in the Northwest. BPA needed to take fuller advantage of its own transmission lines to market surplus power at fully allocated cost.

We began to develop an Intertie access policy in the summer of 1983 with a public notice and request for comment. The purpose of the policy would be to "guide [BPA's] response to requests from nonfederal parties for use of [our] Intertie capacity, within the context of existing contractual obligations." In early 1984, we published a paper discussing the major issues on Intertie access that had been identified to that point.

In July of 1984, we proposed an Intertim Near-Term Intertie Access Policy (Interim IAP) that would be in effect while a long-term policy was being developed. We held public meetings and technical sessions on the proposal. In September of 1984, BPA implemented its interim policy. We expected that the Interim IAP would be in effect for approximately six months pending further study of the issues. The policy responded both to increased nonfederal demand for access to the Intertie and a worsening BPA financial outlook.

We decided to strike a middle ground among all of these needs. Our first concern was to retain sufficient Federal Intertie capacity for our own use to aid us in meeting our costs, including our Treasury payments. This required that BPA have access to the California market at all times to sell significant amounts of surplus firm power and nonfirm energy. Our second concern was to provide the opportunity for Northwest utilities to sell their own firm and nonfirm surpluses to California buyers. This was important for economic as well as legal reasons. With respect to Canadian and other extraregional utilities, we took the position that their needs were to be met last.

The Interim IAP provided BPA and each Northwest generating utility with long-term access equal to their respective surplus firm power -- this number could not be increased by new construction. Only firm sales were allowed. No new capacity-energy exchanges, capacity sales, or seasonal exchanges were allowed. No firm capacity was reserved for extraregional entities.

Short-term capacity was made available on an hourly basis for BPA and each Northwest generating utility according to "Formula Allocation." Allocations were made on a pro-rata basis based on each entity's declarations of available surplus energy for sale. Entities could not transfer their allocations among themselves. Extraregional entities would be granted hourly access only when all needs of Northwest entities had been satisfied.

Under the Interim IAP we were unable to make commitments for long-term power sales because of requirements imposed by the National Environmental Policy Act. We provided the opportunity to make short-term firm arrangements only until July 1986. We also limited resources eligible for export to those in operation, removing incentive to construct new resources potentially damaging to the environment.

The Interim IAP faced judicial review in Department of Water and Power v. BPA, 759 F.2d 684 (9th Cir. 1985). The Department alleged that (1) BPA could reserve only enough capacity on the Intertie to deliver existing sales; (2) BPA could not interfere with competition by allocating shares of the Intertie on an hourly basis; and (3) BPA could not discriminate against Canadian access to the Intertie.

In its opinion, the Ninth Circuit upheld BPA on all points. The court held that (1) Congress intended that we have first priority on the Intertie for our existing and projected sales; (2) Congress did not intend for BPA to compete with other utilities for access to the Intertie and therefore BPA could allocate Intertie capacity among itself and Northwest utilities in a nondiscriminatory manner; and (3) BPA was required to provide access to U.S. extraregional utilities before providing access to Canadian power.

Near Term IAP. In January 1985, we released a draft "Near-Term Intertie Access Policy" (NTIAP) for public comment. During the spring of 1985, the existing Interim IAP was extended twice while BPA prepared the final near-term policy.

In May 1985, after completing an environmental assessment, BPA issued the NTIAP. In all but minor ways, it was identical to the Interim IAP. The short-term nature of the policy was based on the need to conduct extensive environmental analysis of providing for long-term firm transmission for Federal and nonfederal resources. We consequently initiated an environmental impact statement on alternative long-term policies.

In establishing the policy, we stated that the Interim IAP had achieved the primary goal of assuring BPA access to the California market at prices based on our fully allocated costs. Though prices for Northwest nonfederal power had remained relatively stable under the Interim IAP, we found that prices for BPA's surplus power had increased to the levels paid by California buyers for other Northwest power. Overall, Northwest power remained competitive with other power supplies available to California.

The California Energy Commission and the California Public Utilities Commission challenged the Near Term IAP. Petitioners alleged that: (1) the NTIAP was a rate established without the process required under section 7 of the Northwest Power Act; (2) basing the NTIAP on BPA's financial needs was arbitrary and capricious; (3) BPA was unlawfully discriminating against extraregional utilities; (4) the NTIAP failed to conform to antitrust policy; and (5) BPA unlawfully excluded new generating resources from Intertie access.

On November 6, 1987, the Ninth Circuit again upheld our policy against legal challenge. The court held that: (1) the NTIAP was not a rate; (2) our financial rationale for adopting the policy was reasonable; (3) BPA and Northwest utilities have priority access over extraregional utilities; (4) our balance of antitrust policy with other requirements was sufficient, although the court suggested that BPA review and consider the CEC alternative for Formula Allocation in the development of its LTIAP; and (5) exclusion of new generating resources from the Intertie for environmental reasons was justified. California Energy Commission v. BPA, 831 F.2d 1467 (9th Cir. 1987).

Long-Term IAP. Public involvement in the development of the LTIAP has been extensive. During the winter of 1985-86, we held several public meetings on the topics of long-term wheeling, nonfederal subscription rights to the Intertie, and access for extraregional resources. In March 1986, we issued a "Discussion Paper of Major Issues in the Development of the Draft Long-Term Intertie Access Policy."

In October of 1986, we issued our first proposed LTIAP and our draft "Intertie Development and Use Environmental Impact Statement" (IDU EIS) for public review and comment. The proposed LTIAP differed from the NTIAP in the following significant ways:

1. Long-term (20-year) firm wheeling (Assured Delivery) contracts;
2. Increased procedural requirements and harsher remedies for hydroelectric resources destructive of fish resources;
3. A "Hydro Cap" for spot-market allocations during "Condition 1" to ensure that utilities with hydro resources, particularly BPA, would have sufficient access to the Intertie during high water conditions;
4. Access for new resources necessary to support long-term firm transactions over the Intertie;
5. A requirement that nonfederal Intertie oweners use their own capacity before making demands for access to the Federal Intertie;
6. Access for resources entitled to priority under Northwest Power Act section 9(i)(3);
7. A requirement that utilities exporting firm energy either commit to BPA service to meet their load growth or waive BPA's obligation to provide such service.

Extensive written comments were received on this proposal. During the summer of 1987, the Administrator held a series of face-to-face meetings with utility executives and interest groups for a frank discussion of the issues.

Based on these comments and discussions, we issued a second draft LTIAP on December 15, 1987. Changes from the October 1986 draft were intended to provide greater specificity and a wider variety of transactions for purposes of greater planning certainty and enhanced revenue protection to BPA. The revised proposal contained the following changes:

1. A near doubling of the amount of Intertie capacity set aside for nonfederal utilities by providing 440 MW for seasonal exchanges;
2. Additional capacity for long-term transactions if they involve a joint venture with BPA;
3. "Mitigation" requirements on firm transactions to reduce adverse impacts on our revenues resulting from providing long-term firm Intertie capacity to nonfederal utilities;
4. Allocation under Condition 1 based on the size of the market rather than the amount of available Intertie capacity;
5. A statement that BPA would change the method of allocating short-term capacity to nonfederal utilities during Conditions 2 and 3 when the third AC Intertie was constructed;
6. Prohibition of the transmission of the output of new hydroelectric projects located in "protected areas" within the Columbia River Basin.

Since releasing this "revised draft" policy last December, we have used a combination of formal and informal processes to better explain our proposal and better understand the positions of others. As a government agency, we are required to conduct a structured record-building process. At the suggestion of the California Energy Commission and the California Public Utilities Commission, we used a mutually agreeable moderator during four public sessions to ensure that we heard every point of view. Since December, the formal process has yielded over 3,000 pages of transcript and written comments, which we have reflected in our decision. A total of 149 written comments were received on the draft policy.

However, we did not stop there. Our project manager and staff have spoken informally to each utility and group expressing an interest in the policy.

Section 3. Concepts And Terms In The LTIAP

This section briefly discusses the provisions in the Long Term Intertie Access Policy and introduces some of the technical terms and concepts in the policy.

Assured Delivery means long-term firm contracts for delivery of power over the Intertie. The long-term commodity market between the two regions historically has been underdeveloped. The Interim and Near Term access policies did not provide for such transactions. Permitting long-term energy sales and exchanges can allow utilities to take advantage of the regional diversities between the Northwest and California. This will decrease the cost of power for both regions and defer future resource construction.

A **Scheduling Utility** is the Northwest portion of a nonfederal utility that operates a generation control area within the Northwest, or any utility designated as a BPA "computed requirements customer." The LTIAP will provide 800 MW of Intertie capacity to Scheduling Utilities for Assured Delivery service. This amount may be increased after the proposed third AC transmission line is completed.

Of the 800 MW made available for Assured Delivery service, 444 MW is reserved for utilities with a firm power surplus for any type of transaction up to each utility's total firm power surplus as shown in a utility's **Exhibit B**. A utility's Exhibit B as set in the Policy cannot increase. The remainder of the 800 MW is available to all Scheduling Utilities for any type of long-term energy transaction on a first-come, first-served basis.

Utilities which own or control transmission lines of their own to California may receive access on the Federal portion of the Intertie after using their own capacity first. This provision attempts to distribute equally the benefits of the inter-regional transmission service.

Mitigation means compensatory requirements imposed on a utility in return for an Assured Delivery contract. Mitigation helps offset operational and economic problems attributable to a Scheduling Utility's firm power transaction that inhibit BPA's ability to generate revenues. The LTIAP allows utilities the flexibility to negotiate contract-specific mitigation measures or to choose the "generic" mitigation measures outlined in the Policy.

Formula Allocation means the Intertie capacity made available to a particular utility for short-term sales of energy on the spot-market. This is the other important energy commodity market the Intertie serves in addition to long-term sales. Due to varying water and weather conditions, hydro-based Northwest utilities and BPA often have surplus energy to sell on the spot-market. If this energy goes unsold it may be spilled over dams, wasting the energy potential. Northwest utilities and BPA also use this market for selling surplus firm power on a short-term basis. Utilities in California have short-term needs that are met by the spot-market. Historically, the Intertie has been used mainly to serve this market. Billions of dollars of benefits have flowed between the regions since the completion of the Intertie in 1968.

BPA has provided a methodology for allocating the remainder of the Intertie capacity after first providing for BPA firm contracts and Assured Delivery. This methodology varies with three differing conditions on the Intertie. BPA declares **Condition 1** when the Federal Columbia River Power System (FCRPS) is in likelihood of spill. **Condition 2** is when the FCRPS is not likely to spill but the supply of declared surplus energy in the Northwest exceeds the capacity of the Intertie. Finally, **Condition 3** is when the supply of declared surplus energy in the Northwest is less than the capacity of the Intertie.

During Condition 1 it is critical to provide sufficient Intertie access to both BPA and Northwest utilities in order to avoid unnecessary waste of hydroelectric resources. During spill or likelihood of spill conditions the amount of potential generation far exceeds the capacity of the Intertie. Consequently, Condition 1 reserves specific Intertie shares for utilities with energy to sell. Conditions 2 and 3 are more competitive, relying more on the marketplace to determine which nonfederal utility receives access to the facility.

Protection of fish and wildlife is an important part of this policy. BPA is committed to preserve and enhance its programs and investments for fish and wildlife in the Columbia River Basin. The LTIAP adopts the **Protected Area** concept first proposed by the Northwest Power Planning Council's staff. The LTIAP prohibits Intertie access to resources developed in river and stream reaches within the Columbia River Basin designated by BPA as Protected Areas due to the presence of wildlife, high-value resident fish, and anadromous fish (fish that migrate to and from the ocean). The LTIAP will reduce Intertie access to a utility if it builds or purchases power from a project located in a protected area.

Section 4. Environmental Consequences

Council On Environmental Quality regulations for implementing the National Environmental Policy Act require that we identify any environmentally preferable alternatives within the range of alternatives considered in arriving at our decision. That is the purpose of this section.

Three approaches to Formula Allocation for hourly access to the Intertie were considered in arriving at the method contained in the LTIAP. These included the Pre-IAP, Proposed, and Hydro-first procedures. Analyses presented in the IDU EIS (volume 1, chapter 4) indicate no significant difference in the environmental effects of the Pre-IAP and Proposed Formula Allocations. The Hydro-first Formula Allocation would result in slight increases in Northwest hydro generation and small reductions in Northwest coal generation (IDU EIS, volume 1, section 4.1.2.2). The changes in hydro operations would not be significantly more adverse for Northwest fish resources (IDU EIS, volume 1, section 4.2.3) than those resulting from the other two Formula Allocation approaches. The decrease in coal operations would result in a small reduction in air pollution in the Northwest. However, this would be offset by small increases in air pollutant emissions as a result of increased operation of oil and gas plants in California and coal plants in the Inland Southwest (IDU EIS, volume 1, section 4.3.2). Overall, from an environmental perspective, the Formula Allocation options do not differ significantly.

With regard to Assured Delivery, environmental analyses were conducted for alternatives involving amounts of capacity ranging from 0 to 800 MW for nonfederal firm transactions (IDU EIS, volume 1, section 4.1.3). Several environmental tradeoffs were identified in these analyses. Assured Delivery results in small increases in new resource development in the Northwest and reduced development of new resources in California and the Inland Southwest (IDU EIS, volume 1, section 4.4). It also has the potential, at least regarding seasonal power exchanges, to have significant adverse effects on resident fish at Hungry Horse reservoir (IDU EIS, volume 1, section 4.2.3.3) and on cultural resources surrounding the following storage reservoirs: Grand Coulee, Hungry Horse, Albeni Falls, Libby (particularly), and Dworshak (IDU EIS, volume 1, section 4.2.2.3).

Assured Delivery is also associated with slight increases in pollutant emissions in the Northwest and slight emission reductions in the Southwest (IDU EIS, section 4.3.2), though neither of these effects is considered significant. On balance, given the mitigation measures taken by BPA to address the adverse effects of Assured Delivery on resident fish and cultural resources, the provision of Assured Delivery for power sales and seasonal power exchanges is neither more nor less environmentally preferable than denial of such access.

The fish and wildlife protection measures included in the LTIAP are intended to ensure that our fish and wildlife investments are not jeopardized. Their inclusion in the policy is environmentally preferable to their absence.

A more wide-ranging definition of protected areas may be environmentally preferable to one limited to the Columbia basin. However, we have chosen to focus on the basin to comport with the range of our fiscal investments, relying on other regulatory processes to assure protection outside the basin. It cannot be concluded that any significant environmental benefits would derive from extension of BPA's protected areas beyond their current limits.

The decision on the Intertie Access Policy is based in part on the IDU EIS. Subsequent decisions on the DC terminal expansion, the Third AC Interconnection and potential power marketing actions will also be based on the IDU EIS.

PART TWO

TRANSMISSION CAPACITY AVAILABLE FOR SPOT MARKET TRANSACTIONS

"FORMULA ALLOCATION"

Section 1. Federal Capacity Needs

ISSUE NO. 1: **Should the LTIAP accommodate all BPA's transactions on the Intertie, and make only the residual capacity available to nonfederal utilities (the "Federal-first" option)?**

REFERENCE: **1987 draft policy §5(c)**
Final LTIAP §5(c)

A. BPA Proposal

It is important to distinguish between two distinct commodity markets served by the Intertie. The long-term market consists of firm power commodities that provide capacity-deferral value to California utilities and, in the case of certain types of exchanges, to Northwest utilities as well. The short-term market consists of spot-market commodities (both firm and nonfirm) that allow California utilities to displace their own generation (principally oil- and gas-fired units) whenever their decremental costs are greater than Northwest selling prices (including wheeling and losses). BPA and Northwest scheduling utilities depend on the same Intertie capacity to engage in both long-term and short-term transactions. 2/

If we were concerned only about BPA firm sales, large amounts of Intertie capacity could be made available to others without material revenue losses for BPA. Projected BPA firm power sales to California would utilize only a portion of the full Intertie.

2/ Except for PGE and PP&L, which have their own Intertie capacity.

A more difficult allocation issue arises because of BPA's need to make spot-market sales. If our only objective were to maximize revenues available for Treasury repayments, supply conditions on the Federal hydro system during normal hydrological conditions would cause BPA to load the entire Intertie with Federal energy 74 percent of the time during the spring runoff from January through June (46 percent of the time over a year), just to make spot-market sales. 3/ Tr. 472. During wet years, we would utilize even more. If we satisfied all these Federal needs for transmission capacity before making <u>any</u> capacity available to others, nonfederal utilities would receive little Intertie capacity for their spot-market sales and <u>no</u> capacity for their year-round, firm-power transactions.

This is the "Federal-first" method of Intertie allocation that is so attractive to our total requirements customers. Under Federal-first, BPA would utilize whatever Intertie capacity was necessary to sell all its firm and nonfirm energy to California. No nonfederal utility would gain access until all BPA sales had been made. By utilizing the Intertie in this manner, we would cover more of our costs from sales to California utilities, lessening the upward pressure on rates to total requirements customers. 4/

3/ These figures are based on present Intertie capacity and surplus amounts (including 846 average MW of surplus Federal firm energy). Percentages, based on monthly averages, would tend to increase if we assumed that Federal energy sales were concentrated into hours of peak demand.

As Intertie capacity increases with the DC terminal upgrade and addition of a third AC line, the percentages would likely decrease. However, between January and June in years with average water, we will often have energy sufficient to load the entire Intertie even if rated at 7,900 MW.

4/ Some commenters seem to believe that Federal-first would apply only to BPA's usage of the Intertie for firm power sales. However, the Federal system was planned and is now operated to produce optimum amounts of firm and nonfirm energy. <u>U.S. Dept. of Energy - Bonneville Power Administration</u>, 29 FERC ¶63,039, p. 65,123 (1984) (administrative law judge's findings of fact), <u>affirmed</u>, 36 FERC ¶61,335 (1986). This fact and underlying legislation, described in the text, make it clear that no distinction between firm and nonfirm transactions need be drawn.

Support for this proposal is found in two of BPA's organic statutes. Section 6 of the Regional Preference Act, 16 U.S.C. §837e, states that Intertie capacity "which is not required for the transmission of Federal energy ... " shall be made available for transmission of other electric energy. Section 6 of the Federal Columbia River Transmission System Act, 16 U.S.C. §838d, provides that "[t]he Administrator shall make available to all utilities on a fair and nondiscriminatory basis any capacity in the federal transmission system which he determines to be <u>in excess of the capacity required</u> to transmit electric power generated or acquired by the United States" (emphasis supplied).

The United States Court of Appeals held in <u>Department of Water and Power v. BPA</u>, 759 F.2d 684, 692 (9th Cir. 1985) that these statutes require BPA to "reserve sufficient Intertie capacity not only for its current needs but also for its 'foreseeable' future needs, so long as the agency does not compete with other utilities on the mere speculation that it 'may have energy available' sometime in the future to sell to the same customer." The availability of nonfirm energy generated at Federal hydro projects is not a matter of speculation. "In four out of five years, large amounts of nonfirm energy are available because streamflows seldom are anywhere near as low as historic records." <u>U.S. Dept. of Energy - Bonneville Power Administration</u>, 29 FERC ¶63,039, p. 65,123 (1984) (administrative law judge's findings of fact).

BPA has never utilized a Federal-first policy to determine who may use the Intertie. Allocation methodologies date back to the "Exportable Agreement" (Contract No. 14-03-73155), executed in 1969. This contract among BPA and Northwest generating utilities allocates Intertie capacity when the Federal hydro system faces spill -- the condition in which flood-control restrictions on the system force water to be "spilled" past turbines without generating electricity. [5/] The Exportable Agreement allocates Intertie capacity on the basis of each Northwest seller's declared surplus energy in relation to total Northwest declared surplus supply.

Without a policy that provides for long-term transactions, this share-and-share-alike arrangement still makes it difficult for utilities to engage in firm power transactions over the Intertie. There is nothing in the Exportable Agreement to ensure that a utility's pro-rata share of Intertie capacity during spill conditions will be sufficient to cover any firm obligations. In this sense, the Exportable Agreement makes all Intertie wheeling service interruptible -- with two specific exceptions. [6/]

Both the Interim IAP and the NTIAP carried forward the Exportable Agreement's pro-rata sharing concept, denominated "Condition 1." The 1986 and 1987 draft LTIAPs also utilized Condition 1.

BPA's Interim IAP, NTIAP, and draft final policies have also shared Intertie capacity among Federal and nonfederal utilities during all other Northwest energy supply conditions. Condition 2 is declared when the Federal hydro system is not likely to spill, but energy supply declarations by Northwest generating utilities exceed available Intertie capacity. Each utility then receives a pro-rata allocation of capacity. Condition 3 is declared when the Federal hydro system is not likely to spill and energy supply declarations by Northwest generating utilities are less than the available Intertie capacity. Each utility receives capacity to transmit its full declaration; extraregional utilities have access to remaining capacity.

5/ Spill occurs when river flows exceed the generating capability of a particular hydro project or when flows exceed the demand for power.

6/ Firm wheeling was provided for two seasonal exchange transactions involving WWP, SCE, and SDG&E.

In reviewing the Interim IAP, the court of appeals upheld BPA's action to reserve a pro-rata share of Intertie capacity for Federal sales under the three conditions. Responding to an allegation that BPA should be required to compete with other Northwest utilities for Intertie access, the court wrote in Department of Water and Power v. BPA, 759 F.2d at 692:

> it is clear from the legislative history that Congress did not intend BPA to compete with other Northwest utilities for access to the Intertie. The theme of the [Preference] Act is that BPA, as owner and operator of the Intertie, should be allowed preference in transmission of its electricity as necessary to meet its statutory mandate of being self-financing. Only if the agency still has capacity remaining on the Intertie after it has sold available and foreseeable power, is it required to make the Intertie available to other utilities.

The court has not addressed directly the question of whether we must reserve for BPA Intertie capacity greater than a pro-rata share. This Federal-first issue seems to be open for consideration under the LTIAP. 7/

B. Summary of Comments

The Exportable Agreement expires December 31, 1988. BPA's total requirements customers therefore suggest that we face a new decision about allocating Intertie capacity for spot-market sales. These customers want us to adopt a Federal-first policy that ensures that BPA retains enough Intertie capacity to market all of its surplus energy. The DSIs claim that applicable statutes require a Federal-first policy to ensure that the agency repays the Treasury and keeps its rates to industrial customers as low as possible. Tr. 401.

7/ There are two discrete issues pertaining to Formula Allocations. The first issue deals with BPA's usage in relation to nonfederal utilities. The second issue relates to the appropriateness of making an individual allocation of capacity available to each nonfederal utility in the Northwest. This part of the decision deals with only the first issue.

Speaking for utilities that rely on BPA for their total energy requirements, WPAG states the argument for a Federal-first policy most strenuously. WPAG would reduce the capacity made available to nonfederal utilities and impose a new charge on the capacity we make available:

> [After the Exportable Agreement expires] BPA will have no contractual obligation to continue this sharing of Federal Intertie capacity with non-Federal entities. It appears that continuation of Formula allocation will cause BPA to lose about $50 million annually. It is time for BPA to discontinue this practice of giving up Federal Intertie capacity it could use in order to facilitate non-Federal sales. BPA should either commence a policy under which it takes whatever amount of Intertie it needs for nonfirm sales, or imposes a fixed per kilowatt charge on non-Federal utilities to reimburse it for revenues foregone due to operation of the Formula allocation provisions. WPAG, #3-201, p. 5.

NGPU also supports a Federal-first policy but recognizes that such a policy choice would be controversial. While NGPU believes that BPA should not become the "deep pocket" for the region by adopting a policy which harms its revenues, NGPU admits the problems associated with adopting a Federal-first policy:

> BPA would likely achieve its greatest revenues under such a policy although there would be severe utility and political unrest. BPA has long since abandoned such a policy...We understand the need for cooperation within the utility industry and the desire to share markets and try to operate the power system as if it is under one ownership. NGPU, #3-100, p. 2.

Other total requirements customers supported a "Federal-first" policy, arguing that BPA owes them a responsibility to maximize revenues through Federal sales over the Intertie. Umatilla Electric Coop., #3-104, p. 1; Benton Electric Coop., #3-163, p. 1; Big Bend Electric Coop., #3-90, p. 1; Clark County, Wash., PUD, #3-109, p. 2; Harney Electric Coop., #3-103, p. 1; NGPU, #3-100, p. 2; NIU, #3-081, p. 1; Ferry County, Wash., PUD, #3-83, p. 1; Vigilante Electric Coop., #3-139, p. 1.

The CEC also supports a Federal-first policy by which BPA would reserve enough capacity for its own needs. CEC Chairman Imbrecht believes BPA "should reserve to itself, on a long-term basis to deliver, capacity sufficient to deliver the surplus firm power and nonfirm energy that it is reasonably likely to market." Tr. 419. Under CEC's alternative Formula Allocation methodology, no nonfederal utility would gain access to the Intertie until "[a]fter BPA's allocation has been sold . . . ." CEC, #3-218 (Attachment 1). Also, CEC proposes that "BPA could restrict competition with its sales when it is selling at or below [its] 'cost-based' [nonfirm energy] rate, but permit competition with its sales when it sets a rate higher than its fully allocated cost." CEC, #3-218, p. 16.

This recommendation contains a qualification, however. Chairman Imbrecht would also require BPA to limit its Intertie usage each hour to "capacity needed to deliver its actual sales for that hour." Id. CEC does not explain how we might preschedule Intertie usage 24 to 72 hours in advance, based on actual sales which may or may not materialize later on a real-time basis.

Among California utilities, SDG&E supports a policy under which "BPA simply set[s] aside a fixed amount of Intertie capacity needed for its own use and make[s] the remainder available for use by willing buyer and seller utilities on a fair and non-discriminatory basis." SDG&E, #3-196, p. 1.

Another California utility, PG&E, also advances as one of three alternative policies a Federal-first proposal whereby we would reserve two-thirds of the available Intertie for BPA's energy sales. PG&E, #3-188, appendix, pp. B-2, B-3. The remaining one-third would be made available as a block to nonfederal utilities. Id. We will address this PG&E alternative in greater detail later in this decision.

As one would expect, Northwest generating utilities unanimously oppose a Federal-first policy. They support continuing the allocation methodologies used in past Intertie access policies that gave BPA no more than a pro-rata share of capacity. For example, PGP concludes:

> The idea of setting aside intertie capacity for BPA's nonfirm energy transactions and in effect, reducing any non-federal utility's Formula Allocation so that BPA can sell all of its energy is not economic, is inefficient, and is illegal. PGP, #3-194, p. 8.

These are strong words, left unexplained in PGP's comments. However, PGP's message is unescapable: the LTIAP should not reduce publicly owned utilities' sales over the Intertie. In its reply comments, PGP suggests that nonfederal utilities would react to a Federal-first policy by using their own nonfirm energy to serve their loads and thus displace firm BPA power sales. Id. PGP is supported by the Tacoma, Seattle, Eugene, and Chelan publicly owned generating systems. TCL, #3-130, p. 1; SCL, #3-136, p. 1; EWEB, #3-137, p. 1; and Chelan, #3-121, p. 1.

PPC, which represents a consortium of public generating and nongenerating utilities, sided with the former on this issue. It asks "that some kind of allocation mechanism be continued under Condition 1 and 2." PPC, #3-125, p. 4.

Investor-owned utilities also side with the public generators. WWP claims the present allocation system is supported by existing law and ensures widespread use of this regional resource among Northwest generators. WWP, #3-122, pp. 22-23. Allocation of Intertie capacity adds to the transmission resources of Northwest generating utilities. Id., p. 22. See comments of Montana Power Co., Utah Power and Light Co., and the Intercompany Pool: MPC, #3-111, p. 1; UP&L, #3-191, p. 1; ICP, #3-131, p. 1, and ICP, #3-199, p. 4.

PSP&L opposes any Federal-first policy. It states that BPA is not entitled to receive any "preferential or disproportionately large allocation of Intertie capacity for nonfirm transactions." PSP&L, #3-117, p. 5. However, in oral comments PSP&L seemed to argue both for and against Federal-first. On the one hand, it claimed that "the idea of BPA-first is something that never arose during the [1964] Intertie negotiations." Tr. 479. On the other, PSP&L argued that the Intertie was a regional resource which BPA would use for its own purposes, "the balance of which would be made available to the Region and allocated appropriately within the Region." Id.

C Analysis and Decision

A strong case can be made for a Federal-first policy in terms of BPA revenue needs. However, this alternative would effectively prohibit the use of Intertie capacity for firm power transactions between Northwest nonfederal utilities and California. Nonfirm energy transactions by nonfederal utilities would also be greatly curtailed. We do not believe that all commenters who advocate Federal-first are aware of this outcome of their proposal.

A more balanced approach allows nonfederal utilities to share Intertie capacity while still permitting BPA to sell all of its firm surplus power and large amounts of nonfirm energy. Of course, this decision causes some jeopardy to our ability to recover costs and meet Treasury obligations: we would utilize less Intertie capacity to make fewer sales. However, commenters such as PSP&L are correct in observing that the Intertie was envisioned as a resource available to nonfederal utilities. The statutes cited above have been interpreted by BPA and the court of appeals to grant the Administrator substantial discretion in exercising business judgment to balance these conflicting objectives.

Another point to be considered is that Federal-first would cause nonfederal generating utilities to use their energy to displace BPA power sales in the Northwest. Maximum Federal usage of the Intertie shifts nonfederal energy to Northwest markets presently served by BPA.

There are other ways of addressing the concerns of total-requirements customers and the Treasury. First, the LTIAP will provide that BPA utilizes at least its pro-rata share of Intertie capacity for Federal spot-market sales during each Formula Allocation condition, regardless of decisions about continuing allocations for nonfederal utilities. Second, we are adopting the "true-up" adjustment in Conditions 1 and 2 for application when BPA is unable to utilize its full Intertie allocations. Third, we are preserving pro-rata allocations for BPA and nonfederal utilities during Condition 1, when spill conditions are most likely to drive our price below the cost of providing spot-market energy. Fourth, the LTIAP will allow us to increase Federal allocations under all conditions when necessary to minimize revenue losses from emergency actions taken to protect fish in the Columbia basin. Each of these provisions is described later in this decision.

We stress the importance of reserving Intertie capacity for BPA under each Formula Allocation condition. This follows the holding in <u>Department of Water and Power v. BPA</u>, 759 F.2d 684, 692 (9th Cir. 1985) ("it is clear from the legislative history that Congress did not intend BPA to compete with other Northwest utilities for access to the Intertie"). Each revenue-protective measure in the LTIAP depends on a pro-rata share of Intertie capacity for BPA.

When we fail to make sales, one of two things must occur. Either our costs must be borne by our total-requirements ratepayers or the Treasury is not repaid. Because the Treasury is the last creditor in line, BPA's payments to the U.S. Treasury are impacted the most. We believe we have a responsibility to establish policies that ensure that BPA sells a significant amount of its surplus. Failure to do so puts at risk BPA's other customers and our ability to make Treasury payments.

It is not reasonable to suggest that we incur revenue losses to be recovered through rate increases to our Northwest customers. As explained above, our total requirements customers have a strong statutory argument -- apparently supported by many in California -- that we should adopt a Federal-first policy to maximize Federal sales over the Intertie. Additionally, we are guided by the directive to provide "the lowest possible rates consistent with sound business principles." Imposing some of the cost of power sold to California on our Northwest customers is not consistent with that directive. By rejecting Federal-first, we incur an obligation to provide these customers with rate stability through alternative means. First among these alternative protections is the reservation of Intertie capacity for BPA's spot-market sales.

If the revenue-protective measures adopted in the LTIAP prove unworkable or unduly controversial, the obvious remedy is not more Intertie access for nonfederal utilities. Instead, it is Federal-first.

ISSUE NO. 2: **How should BPA compensate for side effects of the Regional Preference Act that impair its ability to sell energy in the spot-market?**

REFERENCE: **1987 draft policy §5(c)(1)(B)(ii)**
Final LTIAP §5(c)(1)(B)(ii), §5(c)(2)(B)

A. BPA Proposal

One feature of the 1987 draft was a proposal to compensate for an inhibition of our ability to sell spot-market energy caused by the Northwest Regional Preference Act, 16 U.S.C. §837, et seq. We face a serious revenue problem because of the Regional Preference Act requirement that we quote our energy price to Northwest utilities before making any sale to California.

Northwest demand at our quoted price determines whether energy is surplus to the needs of the Northwest and available for sale to California.

This requirement was intended to give our Northwest customers a first right of refusal on energy before it is marketed to the Southwest. However, the requirement also allows Northwest utilities, which are both our customers and our competitors, to know BPA's price even when we do not know their prices.

The market for power in California is often less than available Intertie capacity because of California minimum generation requirements. When this situation occurs during Condition 1, Northwest utilities are able to employ their knowledge of the BPA price to undercut the BPA price. They can use their allocations to cut our hourly sales to a small Southwest market just when we have the least ability to store water for future energy sales. 8/ If a "real-time" BPA pricing iteration were even possible, we would again be required to announce our new price to the Northwest. Regional preference makes BPA a "sitting duck" for its Northwest competitors. We can waste hydro energy, by spilling, in a situation where competition cannot work properly because of the special competitive advantage provided to our competitors under the Regional Preference Act. As the Intertie is expanded and Southwest utilities bring on new generation that cannot be displaced with spot-market purchases, the frequency of this problem will increase.

The 1987 draft policy reduced BPA's vulnerability by reducing the size of Scheduling Utility allocations. We did this by limiting Intertie capacity available for allocation to the size of the California market in Condition 1 situations when market size was less than Intertie capacity. The 1987 draft allocated Intertie capacity to Northwest utilities based on the size of the

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8/ This problem can occur during Conditions 2 and 3 as well. However, we have greater ability to store water under those circumstances.

market in California at BPA's then-applicable rate.

Before making this proposal, we set out to assess its revenue impacts. Analyses indicate that BPA would lose approximately $16.4 million in 1989 if we did not rectify this problem. This loss would decrease to $10.7 million in fiscal year 1992. Beyond 1992 the loss is expected to increase, mainly due to projected fuel price increases. See BPA staff Analysis of Condition 1: Intertie Allocation Alternatives (January 6, 1988).

Allocations based on market size would not necessarily cause the Intertie to be underutilized. Purchasers with low decremental costs may choose to displace those resources with additional energy purchased at BPA's market expansion rates after the first allocations are made. Tr. 36, 203.

During public meetings in January 1988, we heard many criticisms of the latest proposal. On January 27, 1988, we therefore advanced an alternative that would (1) allocate Intertie capacity without regard to California market size, but (2) allow BPA to increase ("true-up") its Condition 1 allocations on subsequent days if its sales into a small California market were cut below its pro-rata share of that market by Northwest competitors with their knowledge of BPA's price. Another notable change in the January alternative is that it does not require us to determine California market size based on price.

B. Summary of Comments

This issue drew comments from both California and the Northwest. The 1987 proposal is opposed by Northwest investor-owned utilities and California utilities and regulators. Some prefer adoption of the January alternative. On the other hand, Northwest public generators favor the 1987 proposal.

ICP objects to allocating to the market size because of the incentive it gives BPA to determine market size. On behalf of Northwest IOUs, ICP states:

> Bonneville has provided itself rate flexibility over a very wide range. Based on its own selection of price, Bonneville will determine the size of the market. Setting a high price can make the market, and resulting allocation, very small. ICP, #3-119, p. 7.

Utilities in California echo this concern. SCE comments that allocating access based on BPA's determination of the California market "constitutes classic price fixing." SCE, #3-187, p. 16. See also CEC Chairman Imbrecht's comments, Tr. 417; and SDG&E, #3-196, p. 2. SMUD and SCE also express concern that the 1987 proposal, if adopted, would leave portions of the Intertie unused. SMUD, #3-183, p. 3; SCE, Tr. 435.

ICP indicates that the proposal discussed at the January 27 public meeting "solves our concerns about ... allocation to a market." ICP, #3-119, p. 8. WPAG's total-requirements customer membership agrees:

> Of the two proposals offered by BPA, it appears that the most recent offering would be the most workable. It eliminates the notion of allocating to the market, which seemed to raise serious problems. WPAG, #3-123, p. 13.

The following parties also find the January 1988 alternative preferable to the 1987 proposal: MPC, #3-111, p. 6; PG&E, #3-188, p. 31; TANC, #3-182, p. 3; WAPA, #3-189, p. 2; and WWP, #3-122, p. 21.

In contrast, Northwest public generating utilities tend to favor the 1987 draft LTIAP. EWEB comments that:

> [A]llocating to the Southwest market will assure BPA of a fair share of the market, thus providing a measure of Federal revenue protection by reducing non-federal opportunities to undercut price. Second, non-federal utilities will avoid the need to pay for wheeling costs associated with allocation that are greater than the market. EWEB, #3-200, p. 5; see also City of Port Angeles, #3-71, p. 1.

PGP also states that BPA should retain the proposal in the 1987 draft policy. PGP, #3-194, p. 6. To prevent portions of the Intertie from going unused, PGP suggests that Condition 1 could occur in two steps. "[T]he allocation is made first at BPA's applicable rate. Then, BPA should allocate remaining Intertie access based upon markets available through BPA's market expansion rate." Id.

PGP believes that the true-up mechanism will introduce marketing uncertainty for nonfederal utilities. PGP, #3-194, p. 7. SCE fears that "BPA's proposal will eliminate nonfederal allocations when BPA's energy is uneconomic to the Southwest because BPA over-prices its energy." SCE, #3-187, p. 18.

C. Analysis and Decision

Given the support for our 1988 alternative proposal from a cross section of interest groups, we see no reason to adopt the 1987 proposal that Condition 1 allocations ever be based on market size. The 1988 alternative satisfies the conflicting concerns about market manipulation and revenue protection.

We will attempt to utilize the full capacity of the Intertie during every Condition 1 hour. The BPA price will be known in advance to our Northwest customer/competitors pursuant to the Regional Preference Act; however, that price will not be used to limit the spot-market. In determining Intertie access, BPA will not need to estimate the market at any rate. Purchasers and sellers may negotiate any price. See Tr. 816.

SCE expressed some concern that even the true-up alternative might give BPA some ability to manipulate a market. We do not think that this will be the case. After all, the true-up would operate only when (1) the Federal hydro system is either spilling or facing likely spill, and (2) we are losing sales to Northwest competitors knowledgable of our price. On subsequent days, the true-up provides us with some opportunity to minimize spill conditions, or -- if we are not actually spilling yet -- utilize any unsold energy we were able to store on the first day. This is hardly a situation in which we would offer energy at "excessive prices." Compare, SCE, #3-187 p. 18. It is not unlikely that our asking prices would actually decline on subsequent days even with the true-up. There would seem to be little if any upward pressure on price, and Northwest customer/competitors would not know any clear BPA pricing pattern in advance of the notice required under the Regional Preference Act.

No one disputes that the Regional Preference Act causes BPA a revenue dilemma, especially at times when we face spill on the hydro system. The true-up alternative is the least obtrusive remedy. 9/ We believe that it avoids any implication of market manipulation.

Under Condition 2 the Regional Preference Act side effect is somewhat less critical. However, BPA still loses sales by absorbing the difference between the actual market and the allocated capacity of the Intertie. The LTIAP, therefore, now includes a true-up for Condition 2. Since we are more removed from actual spill conditions, Condition 2 true-up is optional rather than automatic. This provision protects BPA's revenues.

It is true, as PGP suggests, that the true-up provision will cause some marketing uncertainty for nonfederal utilities. This uncertainty has heretofore been borne by BPA and its total-requirements customers. The true-up mechanism spreads this uncertainty among other sellers of spot-market energy.

9/ Energy sold by BPA under the operational mitigation provisions of policy section 4(d) will be credited against the true-up account.

ISSUE NO. 3: **Should Federal allocations be increased to minimize revenue losses from emergency actions taken to protect fish?**

Reference: **1987 draft policy §5(a)**
Final LTIAP §5(a)

A. BPA Proposal

On occasion, water must be released from Federal reservoirs in quantities sufficient to cover fish spawning areas, facilitate downstream fish migration, or achieve other measures to protect fish resources. Sometimes, we first learn of the need for these water releases only after Formula Allocations have been established under section 5 of the LTIAP. Without an override provision to increase BPA's allocation, we could be forced to spill water past hydro turbines without generating electricity. The 1987 draft policy gives us the flexibility to increase BPA's allocation when necessary to limit revenue losses associated with actions to protect fish in the Columbia River basin.

B. Summary of Comments

Only two parties commented on this issue. ICP objects to BPA "reserving the right to wipe out nonfederal allocations whenever BPA's fish and wildlife requirements, such as water budget, would otherwise cause spill on the Federal system." ICP, #3-119, p. 10. See also Tr. 378. The other comment comes from PSP&L: "BPA may not reduce the amount of Intertie capacity available for Formula Allocation to ... 'minimize revenue losses associated with actions taken to protect fish in the Columbia River drainage basin.'" PSP&L, #3-117, p. 5. Neither commenter elaborated on its position.

C. Analysis and Decision

The LTIAP retains this provision, which is necessary to cover those situations when BPA must take emergency actions to protect fish and wildlife; for example, when entities managing the fish and wildlife resources in the Columbia River Basin call us on short notice to release water. We need to protect BPA's revenues from unforeseen releases of stored water.

This provision will accomplish three objectives. First, it gives BPA the ability to act quickly to protect fish resources in the Columbia River Basin. When the situation arises, we will not be forced to call the scheduling utilities and rely on their good will to relinquish a portion of their allocations. This will save time. Second, it reduces all allocations proportionally, thereby equitably spreading the impact among all utilities. Third, it protects us from unnecessarily losing revenues due to circumtances beyond our control.

We stress that the provision covers only extreme circumstances in which BPA lacks sufficient prior notice of the need to change the water release and therefore has been unable to make an adequate declaration.

ISSUE NO. 4: **How much flexibility should we incorporate into the criterion for implementing Condition 1?**

REFERENCE: **1987 draft policy §5(c)(1)(B)**
Final LTIAP §5(c)(1)(B)

A. BPA Proposal

Under both the 1986 and 1987 draft policies, BPA declares Condition 1 when the Federal hydro system is in "spill or likelihood of spill." This criterion is intended to provide our schedulers with enough flexibility to avoid spill whenever possible. A more rigid definition would push us closer to the time when flood control restrictions force spill. Once the Federal system begins spilling, water cannot be stored for later sale and hydro energy is wasted.

B. Summary of Comments

Of the California utilities and regulators only SMUD and PG&E commented on this issue. BPA's total requirements customers offered no comments.

Northwest generating utilities, public and private, ask that BPA should quantify the definition of "spill or likelihood of spill." Although these comments are short on elaboration, we discern that generating utilities believe we will use the flexibility of the proposed criterion to advantage BPA in relation to nonfederal sellers. PP&L asks us to bound our flexibility with a definite limit, such as likelihood of spill over the next 30 days. PP&L, #3-138, p. 2. PGP states, "We encourage BPA to 'announce' a condition based on anticipation of spill within a reasonable period of time, or upon a determination by BPA that energy would be wasted otherwise." PGP, #3-194, p. 8; see also ICP, #3-119, p. 6; PSP&L, #3-117, p. 9.

Among some IOUs, this concern is coupled with dissatisfaction about the Condition 1 Hydro Cap proposal. The Hydro Cap would have given disproportionately large Condition 1 allocations to hydro systems such as BPA's. IOUs did not want the LTIAP to give an impression that only hydroelectric energy would be transmitted during Condition 1. E.g., PP&L, Tr. 218.

SMUD states that "the definition of Condition 1 should be made more precise, particularly since there may be significant incentive for BPA to declare Condition 1 if the proposed mitigation measures are adopted." SMUD, #3-183, p. 3. PG&E in its proposal for a preferred long-term Intertie access policy suggests that Condition 1 be determined by a condition of "spill or imminent spill conditions." PG&E, #3-188, p. 35.

C. Analysis and Decision

BPA schedulers do not believe they can manage the Federal hydro system to minimize the waste of hydro energy if they are constrained to an arbitrary time limit such as the one proposed by PP&L. Anticipating a spill condition is an operational determination that relies on the interplay of numerous unpredictable factors, many subject to sudden change. Arbitrary constraints limit our ability to protect BPA when these conditions change.

The Northwest depends on the hydro power system for a large percentage of its electrical needs. The runoff in this system is highly variable. Average annual runoff is 134 million acre-feet (MAF), but in the past has ranged from a low of 78 MAF to a high of 193 MAF. Monthly mean streamflows (unregulated) can range from 40,000 cubic feet per second (cfs) in January to 1,240,000 cfs in May.

The hydro system consists of many small run-of-the-river projects -- with limited daily or weekly storage -- and much larger "seasonal storage" projects whose storage may be drafted over a year or more before emptying or refilling. Since streamflows do not occur in the same pattern as electric energy requirements, water is used as a storage medium for potential energy.

The streamflow pattern is regulated into a more usable "shape" by controlling project outflow to store energy when natural streamflows exceed load requirements and to release stored energy when needed. Total storage capacity of the system is only about 42 MAF -- significantly lower storage capacity than average runoff. Thus, the hydro system has the potential of producing about 12,000 average MW (aMW) of "firm" energy during low runoff conditions. It can generate about 16,000 aMW on a long-term average basis and about 19,000 aMW in a high runoff year. This means that in planning the coming year there is an additional unknown factor. Up to 7,000 aMW of nonfirm energy may or may not be available.

In January, the first snowpack measurements and forecasts of spring runoff are made. Flood control curves are developed to prevent flooding in the spring, and refill requirements are developed to ensure that firm loads are met and reservoirs refill by July 31. This would not be difficult if accurate forecasts of the January-through-July runoff were available. However, the January forecast is based on actual snowpack and projected precipitation through July. Actual precipitation can vary greatly from projections. Since most storage reservoirs and drainage areas are relatively remote, little accurate data are available on amounts of snowpack loss or gain between surveys.

Even with January-through-July runoff projections updated monthly, flood control requirements may cause a hydro project to be run full-load one month and at minimum the next month to permit refill because of an unexpectedly low snowpack measurement. The closer to July, the more accurate the forecast, since less of it is based on forecasted precipitation. If a reservoir is not drafted enough, flood control will force water to be spilled, a loss that can run to tens of thousands of dollars per hour. With an annual runoff that varies between about 60 percent and 145 percent of normal, and limited storage space, hydro operations is really a continual balancing act between maximizing revenues and the need to refill annually for recreation, fisheries, and to assure future energy needs.

In this context, a 30-day limit on determining the "likelihood of spill" seems completely arbitrary. Of course, what we call flexibility, others call ambiguity. However, this tension has existed to some degree since the Intertie went into commercial operation. The Exportable Agreement, which has governed similar situations since 1969, covers situations where BPA schedulers anticipate "electric energy of the Federal Columbia River Power System ... which would otherwise be wasted because of the lack of a market therefore in the Pacific Northwest at any established rate ... ." Subjective terms in this criterion, which simply repeats language from section 1(c) of the Regional Preference Act, obviously leave much discretion to BPA's schedulers.

During the public meetings, no one rebutted the BPA chief scheduler's statement that we have been able to explain, after the fact, decisions to implement Condition 1 in the past. Tr. 214. On a prospective basis, however, "we're not capable of forecasting all the kinds of conditions we can get into." Id. Therefore, the criterion of the 1987 draft is retained in the final LTIAP.

PG&E asks us to use "imminent spill" as an implementing criterion. "Imminent" is defined as "likely to occur at any moment." Random House Dictionary, 1980. Under such a narrow definition, we could not avoid unnecessary spill. This appears to be a problem of semantics. PG&E's proposal is intended to give our system schedulers some degree of flexibility; however, the "imminent spill" criterion fails to meet this objective.

Regarding SMUD's concern about mitigation requirements for Assured Delivery contracts under the LTIAP, we discuss below the mitigation charge alternative open to any utility as an alternative to Condition 1 mitigation.

ISSUE NO. 5: **Should the LTIAP incorporate the "Hydro Cap" limit to increase allocations for BPA and other predominantly hydro-based utilities during times of likely spill?**

REFERENCE: **1987 draft policy**
Final LTIAP

A. **BPA Proposal**

The 1987 draft policy calls for BPA and Northwest scheduling utilities to declare surplus energy available for export. Whenever the Federal hydro system is likely to spill, each seller would receive a share of Intertie capacity approximating the ratio of its hydro capacity to total Northwest hydro capacity, multiplied by "available Intertie capacity." This sharing based on hydro capacity is called the "Hydro Cap." Since Condition 1 is in effect during times of likely spill, we proposed that allocations favor hydro generation over thermal generation. The Hydro Cap gives larger allocations to BPA and other sellers whose generation mix is predominately hydro. Tr. 219.

We responded to criticisms of the Hydro Cap by advancing an alternative at the public meeting of January 27, 1988. Tr. 804. The proposal eliminated the Hydro Cap and based allocations on all surplus energy declared by Northwest sellers. This January 1988 proposal also contained the "true-up" mechanism described earlier in this decision as a method of protecting BPA revenues.

B. Summary of Comments

Publicly owned generating utilities objected to the Hydro Cap when it was first proposed in the 1986 draft policy. They labeled the provision an "overkill" solution that provided BPA with excessive allocations. EWEB, #1-082, p. 6; PGP, #1-056, p. 18; SCL, #1-090, p. 15. After the 1987 draft policy was released, however, the public generators changed positions. They now appreciate that as hydro systems they too would stand to benefit:

> The Hydro Cap is the appropriate method of allocating Intertie capacity while BPA is in a spill condition. ... It is irrelevant and irresponsible to include thermal generation in the allocation of Intertie capacity while the Northwest's hydro resources are being spilled. EWEB, #3-200, p. 5.

Seattle concurs, stating that a "policy ... where thermal resources are running [at the same] time hydro is spilling, is a policy that is not in the best interests of anybody in the region." Tr. 844. PGP and APAC also support allocations based on the Hydro Cap. APAC, #3-110, p. 2; PGP, #3-124, p. 8.

Northwest investor-owned utilities have more balanced mixes of thermal and hydro resources. PP&L sums up the position of those who oppose the Hydro Cap:

> To limit a Scheduling Utility's formula allocation to hydro capacity unfairly penalizes those utilities who, in cooperation with the rest of the Northwest, developed thermal resources under the Hydrothermal Program to ensure regional adequacy. It also appears that BPA's basis for this discriminatory provision is unsound, since such an allocation basis has no link to the actual total regional energy surplus. PP&L, #3-138, p. 2.

<u>See</u> comments of ICP, #3-119, p. 6; MPC, #3-212, p. 2; and WWP, #3-122, p. 23.

Washington Water Power Co. addressed the public generators' fear that removal of the Hydro Cap would cause Northwest utilities to spill hydro resources while thermal resources were operated to sell energy over the Intertie. WWP's Vice President Bryan stated:

> I think the point needs to be made that once we make a preschedule, that doesn't mean that we don't talk to each other during the day. And at any time that a thermal resource is operating and somebody else in the Northwest has a hydro facility that has surplus and [is] spilling, my company is always willing to take energy in to displace that thermal. We talk to each other hourly as to what's going on in our systems, so I think the issues of operating thermal plants and having hydro plants spilling just doesn't make sense. Tr. 845.

Pacific Power & Light also indicated that it is always willing to displace its thermal with hydro: "If there is energy out there to buy, we'll buy at any time, on an hourly basis, generally." Tr. 846.

Public utility commissions addressing this issue oppose the Hydro Cap. The Wyoming Public Service Commission supports the IOUs' claim that fairness dictates that BPA does not use the Hydro Cap in determining allocations under Condition 1. It states that "thermal generation which is available to the Pacific Northwest during drought conditions, benefits all of the Pacific Northwest including Bonneville. Since Bonneville derives such a benefit it should then give some consideration to these facilities and their owners when the Pacific Northwest is experiencing surplus conditions." WPSC, #3-73 p. 1. The Oregon Public Utility Commission prefers an alternative of allocating available capacity to all resources with a variable cost less than the BPA nonfirm energy rate. OPUC, #3-134, p. 2.

Two California commenters further the argument laid out by the Northwest IOUs. TANC recognizes that when the Northwest is in Condition 1, "there will be base loaded thermal units operating which will be contributing to the surplus condition as well as hydro." TANC believes those utilities should be allowed access to the Intertie during Condition 1. TANC, #3-182, p. 3. SCE also favors abandoning the Hydro Cap. SCE, #3-187, p. 17.

During the January public meetings, those favoring the Hydro Cap advanced a new concern about its elimination. EWEB made the point that "uneconomical resources, such as combustion turbines, could be included in a utility's declaration without any intention by the utility to actually operate them." EWEB, #3-137, p. 4. This is a fear that the thermal-based systems will seek to inflate their Condition 1 allocations by declaring surplus energy from every possible source, including high incremental-cost combustion turbines which operate only on occasion to meet a utility's peak load and do not contribute to a utility's hourly energy surplus. Tr. 822.

A response to this second concern was provided by ICP director Merrill Schultz who pointed out that over-declaration has never been a serious problem:

> [T]here is always the potential of people over-declaring. It hasn't happened. There are good reasons that it hasn't happened. There are people watching. Occasionally, you get stuck with your declaration and have to make good on it. Tr. 830.

As we understand Mr. Schultz's point, it is that utilities would be wary of inflating their declarations with gas-turbine energy at incremental costs of 40 to 50 mills/kWh. Any abuse would become apparent if that utility succeeded in inflating its allocation and then left it unused because its

50-mill resource would command only 18 mills/kWh in a Condition 1 market.

Late in the process, PGP offered a compromise proposal:

> We are concerned that surplus energy declarations are often manipulated to the detriment of BPA and other non-federal utilities. As an example, we oppose inclusion of uneconomic combustion turbines in a utility's declaration. In order to enforce this proposal, we suggest that BPA utilize the concept embedded in the Exportable Agreement, and request, on an occasional basis, documentation which identifies the resource composition of the surplus energy declaration. PGP, #3-194, p. 5.

C. Analysis and Decision

When the Federal hydro system faces spill, other systems might not always be in the same condition. The Hydro Cap could give disproportionately large shares of Intertie capacity to hydro-based utilities when they may not face a threat of spill, while frustrating the marketing activities of utilities with hydro and thermal resources.

We also agree with the ICP that several factors deter over-declarations. First, the take-or-pay feature of our IS-87 transmission rate requires a utility to pay for its allocation regardless of its actual use. Tr. 840. Second, BPA monitors declarations and is aware of each utility's resources and capabilities. We have not observed significant over-declarations under past policies. Tr. 187. From time to time we can request documentation on each utility's declaration as a further assurance against inflation. The content and frequency of such requests are left for BPA power schedulers to resolve in implementing the policy.

Given our adoption of the true-up mechanism and our decision about Condition 1 allocations (discussed below), we do not believe that the Hydro Cap is necessary to protect BPA revenues or avoid spill on the Federal hydro system. Also, the Hydro Cap also does not appear necessary to protect nonfederal utilities from spill.

Section 2. Allocations Of Capacity To Nonfederal Utilities

ISSUE NO. 1:	**How should the policy differentiate between the spot-market Intertie capacity requirements of Northwest and extra-regional utilities?**
REFERENCE:	**1987 draft policy §6 Final LTIAP §§6, 8(b)**

A. BPA Proposal

We proposed to distinguish between Northwest and extraregional needs by limiting extraregional access to Condition 3. During times of likely spill on the Federal hydro system and when Northwest surplus energy supplies could fill the entire Intertie, we proposed to serve BPA and Northwest needs first. This principle and our underlying legal position were reflected in earlier versions of the Intertie access policy expressly affirmed on review. Department of Water and Power v. BPA, 759 F.2d 684, 694 (9th Cir. 1985) ("Congress intended that the Intertie be used primarily for the benefit of Northwest and Southwest utilities and not for the benefit of Canadian utilities"); California Energy Commission v. BPA, 831 F.2d 1467 (9th Cir. 1987).

B. Summary of Comments

No California utility expressly requests that extraregional resources be given Intertie access during Condition 1. However, they do request that extraregional utilities be given access during Condition 2.

PG&E is most adamant in its comments on this issue. Its position is based on legal argument. PG&E claims that 16 U.S.C. §837e and §838d make "no mention of any distinction between utilities inside and outside the Pacific Northwest." PG&E, #3-188, p. 9. PG&E further cites 16 U.S.C. §839f(d) and §839f(i)(3) and concludes that there is "no basis in law for BPA to create a priority in the provision of its transmission services for utilities within the Pacific Northwest." Id.

Turning its attention specifically to Canadian extraregional utilities, PG&E believes that both BPA and the court of appeals in Department of Water and Power v. BPA "misread" the legislative history of 16 U.S.C. §837e. PG&E believes that language of the statute prohibits any distinction between the Northwest and extraregional utilities.

British Columbia Hydro does not request Condition 1 access. Tr. 447-49. BC Hydro has much greater hydro storage capability than the Northwest; it rarely faces a spill condition. Instead, BC Hydro simply requests that we abolish Condition 2 -- with its limitations on extraregional access -- when the Northwest's firm power surplus decreases below 500 average MW. BCH, #3-186, p. 2.

BC Hydro asks for clarification of section 6(b) in which it would receive Intertie access under Condition 2 if it agreed to increased participation in the Northwest's coordinated planning and operation in the Columbia River Basin or to provide other consideration of value. BCH, #3-186, p. 2.

C. Analysis and Decision

We have decided to continue the limitation that allows extraregional utilities Intertie access only during Condition 3. This limitation may be relaxed in the future, as specified in section 6(b) of the policy. Tr. 240.

Our legal authority to grant Intertie access priority to Northwest utilities over extraregional utilities has been fully considered by the court of appeals. The Court has held that Congress intended the Federal Intertie to be used primarily for BPA's present and foreseeable needs. BPA has the authority to establish the terms and conditions of nonfederal access to protect its ability to generate revenue to cover its costs and repay the Federal Treasury.

Capacity excess to our needs must be provided on a fair and nondiscriminatory basis first to Northwest utilities. 10/ Capacity surplus to the needs of Northwest utilities must be made available on a fair and nondiscriminatory basis to U.S. extraregional utilities. Capacity beyond the needs of U.S. extraregional utilities may be made available to Canadian utilities.

Northwest utility priority is clear from the legislative history of the Regional Preference Act and P. L. 88-511 (appropriations for the Federal portion of the Intertie). Congress's listing of the expected Intertie benefits included only those arising from transactions between the Northwest and Southwest. 11/

The only exception was the narrow category of Canadian Treaty power which has priority under section 6 of the Regional Preference Act, 16 U.S.C. §837e. In all other respects, the legislative history states only that BPA "may" contract with Canadian utilities for Intertie transmission of non-Treaty Canadian power. H. Rep. No. 590, supra, p. 3350.

The court also held that Congress did not establish equal priority for extraregional utilities in section 6 of the Federal Columbia River Transmission System Act. 759 F.2d at 694.

Recent legislative actions also support the distinction made between regional and extraregional utilities. Section 9(i)(3) of the Northwest Power

10/ A change in this priority might result from a mutually beneficial arrangement between BPA and an extraregional utility. Department of Water & Power v. BPA, 759 F.2d 684, 694, n.14 (9th Cir. 1985).

11/ H. Rep. No. 590, 88th Cong., 2d Sess. pp. 2, 4 (1964); Conf. Rep. No. 1822, 88th Cong., 2d Sess. 4, 7 (1964); Department of Interior, Report to the Appropriations Committees ... Recommending a Plan of Construction and Ownership of EHV Electric Interties Between the Pacific Northwest and Pacific Southwest, p. 32 (1964).

Act, 16 U.S.C. §839f(i)(3), directs the BPA Administrator to provide transmission and other services "unless he determines such services cannot be furnished without substantial interference with his power marketing program ... ." This is broad discretionary language emphasizing the primary obligation of BPA to cover BPA's costs and repay the Treasury and the requirement to balance all other activities against this obligation. BPA consequently has broad authority to determine that access for extraregional power will substantially interfere with the BPA's power marketing program.

In 1985, four months after the Ninth Circuit issued its opinion in Department of Water & Power, Congress passed an appropriations act authorizing construction of additional Intertie facilities between the Northwest and California. The act expressly provides:

> Nothing in this Act or in the Memorandum [of Understanding between the California utility owners] shall in any way affect, modify, change, or expand the authorities or policies of the Bonneville Power Administration under existing law regarding ... transmission access.

P. L. 99-88, 99 Stat. 293 (1985) (emphasis added).

Late in 1986, Congress passed the Electric Consumers Protection Act, 16 U.S.C. §797(e). A savings clause was inserted (§ 17(a)(4) and (7)) to clarify that the Act was not intended to affect in any way the transmission authorities of Federal power marketing administrations, such as BPA, or to affect the Northwest Power Act. A colloquy on the Senate floor between Senator Evans and Senator McClure, the Senate Energy Committee chairman, indicated their intent that the Electric Consumers Protection Act not affect BPA Intertie access policy upheld in Department of Water & Power:

> [T]he authority of Federal power marketing agencies to regulate access to transmission facilities owned by the Federal government ... has recently been upheld against court challenges ... and it is not the intent of this legislation to alter or diminish that authority in any fashion." 132 Cong. Rec. S.15388, October 6, 1986 (emphasis added).

Priority access for regional utilities over nonregional utilities has a sound policy basis, as well. First, Northwest generating utilities operate their systems in a coordinated fashion with BPA. One major example is the Pacific Northwest Coordination Agreement. Through this agreement, Northwest generating resources are coordinated to produce the most power at the least cost from all of the region's generation, regardless of ownership. This agreement and others depends upon assured access to the region's transmission system to efficiently move power between utilities and from generation to load.

Second, most of the Northwest region shares the hydrologic characteristics of the Columbia River system (which includes the Snake system). It is the characteristics of this system which were the reason for the construction of the Intertie in the first place. High spring flows produce more generation than can be used in the Northwest and which is valuable in California.

The Intertie was built primarily to move this surplus power to California. Opening up the Federal transmission system on an equal basis to extraregional utilities is contrary to Congress's intent to move Northwest power out of the region when it is surplus and potentially spilled.

ISSUE NO. 2:	**Should the LTIAP continue the Condition 2 and 3 practice of allocating individual capacity shares to Scheduling Utilities?**
REFERENCE:	**1987 draft policy §§5(c)(2), 5(c)(3), 5(d)** **Final LTIAP §§5(c)(2), 5(c)(3), 5(d), 5(e), 5(f)**

A. <u>BPA Proposal</u>

Condition 1 exists when we face the likelihood of spill on the Federal hydro system. Pro-rata capacity allocations are made among BPA and Northwest utilities on the basis of their surplus energy in relation to the total Northwest surplus. There seems to be little controversy about the need for a Condition 1 allocation methodology. Support for the basic concept of Condition 1 allocations comes even from PG&E. PG&E, #3-188, p. 35; and PG&E appendix, p. 7 ("During spill conditions the Intertie is allocated to its capacity based on its declarations on a take or pay basis."). 12/

Nonfederal allocations during Conditions 2 and 3 have been far more contentious. California utilities and regulators have argued that the practice of allocating individual capacity shares to nonfederal utilities is anti-competitive and needlessly paternalistic toward the Northwest.

Condition 2 exists when we do not face a likelihood of spill, but declarations of surplus energy from Northwest utilities exceed available Intertie capacity. Pro-rata allocations are made to each Northwest utility declaring surplus energy. 13/ In Condition 3, there is even less likelihood of spill and available Intertie capacity exceeds declarations of surplus energy from Northwest utilities. After Northwest needs are met, residual capacity is made available first to U.S. extraregional utilities and then to Canadian utilities.

Competition. We have proposed Condition 2 and 3 allocation procedures to offset the market power of California utilities over the southern portion of the Intertie. Pro-rata allocations under Intertie access policies mirror Intertie access in California. Four California utilities own approximately 80 percent of Intertie capacity in California. They are extremely reluctant to share their unused capacity among either themselves or nonowners (the "California have-nots"). As a result, we cannot transmit our spot-market

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12/ "Take-or-pay" obligations is apparently a reference to the IS-87 Intertie transmission rate, which remedies over-declarations. Supra, p. 11.

13/ When there is sufficient energy within the Northwest to fill the Intertie, BPA shares capacity with only Northwest utilities. Department of Water & Power v. BPA, 759 F2d. 684, 693-94 (9th Cir. 1985).

products to willing California buyers lacking transmission capacity. Also, access restrictions in California reduce the price for Northwest energy -- including BPA energy -- below levels prevailing in a competitive market.

This is a major concern for BPA, which incurred a net expense of $213 million in fiscal year 1987 and $65 million in fiscal year 1986. Nevertheless, the 1987 draft policy sought to address California's concerns by adding a new section 5(d), which ceased making individual allocations to nonfederal utilities under Conditions 2 and 3 when the third AC line was completed. We concluded that California Intertie concentration would be lessened by addition of this new line in which other California utilities would have ownership. Under our proposal, nonfederal utilities would then compete for access to a broader California market.

However, section 5(d) also contained a qualification designed to provide a test of our conclusion about California market concentration:

> ... 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.

Indirect revenue effects on BPA. A second reason for LTIAP allocation procedures has been concern about the indirect revenue effects of their elimination. Actions that depress nonfederal revenues from California sales harm our balance sheet due to our statutory obligations to Northwest utilities.

A change in Formula Allocation procedures could depress the revenues of Northwest utilities that receive $160 million in annual residential exchange subsidies under Northwest Power Act section 5(c). See Pacificorp v. FERC, 795 F.2d 816 (9th Cir. 1986). Surplus energy revenues are used as a credit in calculating each utility's "average system cost" under the program. Id. When these utilities make less money on sales to California, it has the unfortunate side effect of increasing their residential exchange payments. To some extent, Congress has made BPA an insurer against the risk that Northwest utilities fail in their own California marketing programs.

Different Formula Allocation procedures could also reduce the surplus energy revenues of publicly owned generating utilities. These BPA preference customers buy some of their power requirements from BPA, generate the rest from their own resources, and also use their resources to generate surplus energy for sale to California. If this energy is not sold to California, their recourse is to displace purchases from BPA without notice. City of Seattle v. Johnson, 813 F.2d 1364 (9th Cir. 1987). Our "availability charge," upheld in City of Seattle, has been an incomplete and very controversial remedy to this displacement problem. Two more challenges to the availability charge are pending before the Ninth Circuit.

Throughout discussion of the 1987 draft policy, we asked the public to consider ways in which section 5(d) might be implemented sooner than the commercial operation date of the third AC transmission line. E.g., narrative explanation of the 1987 draft, p. 10 (December 15, 1987); and Tr. 231. On February 11, 1988, we released two sensitivity studies which identify the revenue impacts on BPA of implementing proposed section 5(d) immediately. One study identified revenue losses of $6 million per year, growing to $10 million per year, if the public generators stopped making sales to California and used all their nonfirm energy to displace purchases from BPA. A second analysis studied the growth in residential exchange overheads related to implementing section 5(d). This study showed a BPA cost increase of about $6 million per year. See letter dated February 11, 1988, from IAP project manager.

B. Summary of Comments

California Energy Commission. CEC's first alternative proposes that "BPA could restrict competition with its sales when it is selling at or below this 'cost-based' rate, but permit competition with its sales when it sets a price higher than its fully allocated cost." CEC, #3-218, p. 16. 14/

CEC believes that this prolix alternative would allow us to harmonize revenue concerns with competition. Id., pp. 17-18. The CEC proposal incorporates a mixture of Federal-first principles, a Federal "true-up" mechanism, pro-rata allocations whenever the market price was "at or below the cost of nonfirm energy as determined in the most recent BPA rate case," and

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14/ The "below-cost" component of CEC's first proposal reads:

> "(a) In each hour when BPA declares its nonfirm energy standard rate to be at or below the cost of nonfirm energy as determined in the most recent BPA rate case, BPA shall allocate Intertie capacity first to itself based on the ratio of its declaration to the sum of all declarations, multiplied by the available Intertie capacity. BPA may increase this allocation by multiplying it by a further factor, determined in the most recent rate case, if BPA determines in that rate case that additional capacity is necessary to mitigate the revenue impact on BPA, as predicted in the decision in the most recent rate case, of (i) allowing others to compete with BPA when it sells above cost, and (ii) allowing competition among Scheduling Utilities and Extraregional Utilities. After BPA's allocation has been sold, all remaining Intertie Capacity shall be made available to the remaining Scheduling Utilities and Extraregional Utilities, first come-first served based on first transactions arranged with California utilities. If BPA is unable to sell its allocation at its declared price in time to preschedule the remaining capacity, it may, at its option, (I) lower its price to a market expansion rate in order to sell its allocation and make the remainder of the capacity available to the remaining Scheduling Utilities and Extraregional Utilities, first come-first served based on first transactions arranged with California utilities, (II) sell all available BPA energy using the entire Intertie capacity at whatever rate or rates it can get at or below its initially declared price and allocate those sales, after the fact, pro rata, based on the declarations to those Scheduling Utilities and Extraregional Utilities who wish to participate, or (III) sell what it can at its original price and leave the remainder of the Intertie unfilled." [CEC, #3-218, Attachment 1.]

first-come, first-served allocations under other circumstances. [15]

This alternative is remarkable because it is a Federal-first alternative more extreme than anything ever proposed even by our total-requirements customers. Not only would we reserve all Intertie capacity necessary for BPA firm and nonfirm energy sales, CEC would also allow us to prohibit all nonfederal sales at any price until "[a]fter BPA's allocation has been sold ... ." See footnote 14, above. If we failed to sell all our energy at our asking price, CEC then proposes that we (1) reduce our price to some market-clearing rate and then make residual capacity available to others first-come, first-served, (2) reduce our price and implement a pro-rata allocation plan like the one used in Conditions 1 and 2 of the 1987 draft policy, or (3) adhere to our original price, sell what we can, and "leave the remainder of the Intertie unfilled," Id., thereby prohibiting nonfederal sales.

As we understand the CEC's first alternative Formula Allocation methodology, it would give BPA complete control over Northwest sales whenever the California bid for spot-market energy was "at or below" our cost-based rate for nonfirm energy. What Northwest utility would ever offer spot-market energy below the BPA nonfirm rate, if we could respond by prohibiting nonfederal sales -- even during spill conditions? If we were more concerned about BPA's share of the spot-market than the unit price of our energy, the CEC alternative would permit us to offer energy only at the cost-based rate and prohibit access to nonfederal utilities day after day.

As a variant on its extreme Federal-first policy, CEC suggests that we might offset, in advance, the estimated revenue losses associated with

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15/ The "above-cost" component of CEC's first proposal reads:

> "(b) In each hour when BPA declares its nonfirm energy standard rate to be above the cost of nonfirm energy, BPA shall allocate all Intertie capacity, first come-first served based on first transactions with California utilities."

competition among nonfederal utilities by taking more than our pro-rata share of the Intertie and making the remainder available to other sellers as a block. CEC, #3-218, pp. 17, 44.

> [W]hile most of the attention in the past has been focused on the extreme alternative of a 'BPA first' policy that gives no one else access until BPA has sold all of its energy, we want to suggest ... the alternative of simply mitigating the estimated revenue impacts of allowing competition among non-federal sellers by taking a small amount more than a pro rata share for itself and making the rest available to others as a block. Id., p. 45.

CEC estimates that BPA would normally reserve for itself 60 percent of Intertie capacity available for spot-market transactions. Increasing that amount to 63 percent would offset revenue impacts identified on our two sensitivity analyses released on February 11, 1988. Id., pp. 44, 48.

CEC's second proposal focuses on its perception that the benefits of Intertie transactions should be shared equitably over time between the Northwest and California. "If BPA were serious about trying to share the benefits equally between the regions, it could adopt an LTIAP that would alternate periodically between competition and pro rata allocation." Id., p. 37, note 37. This alternative calls for periodic reassessment of inter-regional benefits from Intertie transactions. If California's benefits were greater than the Northwest's, we would allocate Intertie capacity on a pro-rata basis as in the 1987 draft policy. A year later, we would reassess the balance. If the Northwest were then the net beneficiary, we would cease allocations and make capacity available first-come, first-served.

The cycle would continue annually. This second CEC alternative seems to make interregional controversy an annual event, undoubtedly followed by Congressional oversight hearings and judicial review.

In responding to our 1987 draft policy, CEC criticizes proposed section 5(d) as "an inadequate solution to the anti-competitive aspects of the

LTIAP" because of its vague terminology. CEC, #3-218, pp. 33-36. CEC objects to the lack of criteria for determining whether California Intertie usage is still restrictive after the third AC line goes into commercial operation. It characterized the section as "little more than window dressing which attempts to shore up a legally questionable part of the policy." Id., p. 36.

Pacific Gas & Electric. PG&E, on the other hand, suggests that section 5(d) be implemented "immediately and unconditionally." While stating that Condition 1 allocations are acceptable, it argues that we lack justification for allocating access under Conditions 2 and 3. PG&E, #3-188, p. 24. PG&E proposes these modifications to Formula Allocation provisions:

> During all times other than spill or imminent spill conditions on the Federal Columbia River System, BPA, Pacific Northwest utilities and extraregional utilities compete for access on Intertie capacity available after BPA has met its contractual obligations, including its own firm power transactions, Canadian Treaty power transactions and the provision of long-term firm transmission service ... .
>
> During spill or imminent spill conditions, a formula allocation mechanism similar to that proposed in the LTIAP is used to assign shares of available Intertie capacity to BPA and Pacific Northwest utilities. PG&E, #3-188, p. 35.

Appended to PG&E's comments is an "Economic Analysis of Bonneville Power Administration's Intertie Access Policy," by Decision Focus Incorporated ("DFI appendix"). The DFI appendix, which contains an analysis of three Formula Allocation alternatives, has several unfortunate shortcomings. First, none of its analyses were presented for review in the discussions held at the request of PG&E and other California parties early in 1988. Second, none of DFI's three alternatives correspond exactly to the Formula Allocation modifications (quoted above) proposed in the text of PG&E's comments. Third, DFI analyzed only Northwest markets; it assumes that the California market is competitive.

The DFI appendix describes two alternatives to our 1987 draft policy, denominated "BPA-first" and "Fully competitive when not spilling." PG&E's "BPA-first" alternative is similar to section 5(d) of the 1987 draft policy. DFI appendix, p. B-8. PG&E assumes that BPA revenues equal those generated under the 1987 draft LTIAP; however, share-the-savings pricing governs nonfederal spot-market transactions whenever the Intertie is full. Id., p. B-9. Under PG&E's "Fully competitive when not spilling" alternative, all sales are assumed to be governed by a share-the-savings price cap, established by BPA, whenever the Intertie is full. Id., p. B-10. Whenever the Intertie is not full, energy is assumed to be sold at lower, "market-clearing" prices. Id. That is, PG&E proposes a price cap whenever California demand might bid up energy prices, but no price floor when supply might cause prices to drop.

PG&E compares its calculation of benefits between each of the two alternatives and the 1987 draft in the following table shown in the DFI appendix:

Surplus Nonfirm Revenue Analysis
(FY 1989 $Million/Year)

	LTIAP	Competitive For Non-BPA	Change From LTIAP	Competitive For All PNW	Change From LTIAP
BPA Intertie Sales	182.0	202.3	+20.3	151.6	-30.4
Transmission Revenues	5.6	2.5	-3.1	2.5	-3.1
Expansion Sales	89.3	48.7	-40.6	48.7	-40.6
Total BPA Revenue	276.9	253.5	-23.4	202.8	-74.1
Non-BPA Intertie Sales	53.0	18.0	-35.0	17.9	-35.1
PSW Costs	235.0	220.3	-14.7	169.5	-65.5

Source: PG&E, #3-188, Appendix B, p. B-4.

Several conclusions are apparent from this DFI table, which we assume here to be accurate for purposes of this discussion.

First, PG&E's estimate of Formula Allocation effects on California is $65.5 million per year. See "Change from LTIAP" column. For California to realize this $65.5 million, BPA must forgo $74.1 million in annual revenue. This is not a "zero-sum" game because we would lose revenue in the Northwest as well as in California. 16/ DFI has failed to reflect higher residential exchange overheads in BPA's forgone revenues, so the $74.1 million figure could grow as high as $80 million per year.

Second, of the $65.5 million amount, $30.4 million represents increased BPA revenues under the 1987 draft LTIAP and $35.1 million represents extra revenues to Northwest nonfederal utilities receiving pro-rata allocations under all Formula Allocation conditions. California utilities and regulators have focused principally on the latter nonfederal revenue amount as the "paternalistic" effect of Intertie access policies. However, the measure of this alleged effect, shown in the table row labeled "Non-BPA Intertie Sales," is virtually identical between PG&E's "Competitive for Non-BPA" ($35 million) and "Competitive For All PNW" ($35.1 million) alternative Formula Allocation procedures. If PG&E's concern lies with the LTIAP's treatment of Northwest nonfederal utilities, it should be indifferent as between its two alternatives.

16/ The difference is the result of two changes in the Northwest. As "Non-BPA Intertie Sales" drop by $35.1 million, Northwest nonfederal utilities use more of their spot-market energy to displace higher incremental cost generation in the Northwest. Our "Expansion Sales" drop by $40.6 million, yielding a net loss to BPA of $5.5 million. Also, our Intertie "Transmission Revenues" drop by $3.1 million.

The DFI appendix reference to lost Expansion Sales confirms and materially increases our study results about Northwest public generators' use of spot-market energy to displace our firm power sales to those utilities. Because of the magnitude of DFI's lost "Expansion Sales" figure, we conclude that DFI has also computed the amount of lost nonfirm sales to Northwest investor-owned generating utilities.

Other comments. California utilities and regulators complain that the practice of allocating individual pro-rata shares of Intertie capacity to each nonfederal utility removes any incentive these utilities might have to reduce their prices in hopes of increasing their respective spot-market shares. California's basic position coalesces on the same proposition advanced to the Ninth Circuit in earlier review proceedings:

> CEC and CPUC argue that this pro rata allocation formula is an abuse of discretion because it is anti-competitive and BPA's stated justifications could be achieved by a less anti-competitive alternative. They assert that BPA should be required to adopt a policy whereby it would first allocate to itself whatever capacity is needed to satisfy its revenue obligations, and then allow the remainder capacity to be filled by competitive, spot-market transactions rather than by the pro rata formula. [California Energy Commission, 831 F.2d 1467, 1475 (9th Cir. 1987).]

With two exceptions, this is a description of section 5(d) of the 1987 draft policy. It is also very similar to the "BPA-first" alternative in the DFI appendix to PG&E's comments. The two exceptions relate to treatment of extraregional resources during Conditions 2 and 3 (resolved in this decision at pp. 44-48) and the continuation of pro-rata allocations during Condition 1.

SCE "welcomes" the addition of section 5(d), but "continues to advocate the immediate elimination of all pro rata allocations for nonfederal utilities under all three conditions." SCE, #3-187, p. 19. Edison does not distinguish between spill and nonspill conditions. SCE Vice President Bjorklund proposes that "transactions be prioritized through natural pricing with the least expensive energy used first." SCE, Tr. 436.

Generally, California Intertie owners believe that section 5(d) would place BPA in the inappropriate role of deciding how they share their Intertie. They argue that their Intertie practices carry implicit Congressional sanction and that any problems should be left for judicial resolution under Federal antitrust laws. Hall, PG&E, Tr. 429, and PG&E, #3-188, p. 24;

SCE, #3-187, p. 20; CEC, #3-218, pp. 26-33. They dispute the existence of anti-competitive practices in California and argue that they are not obliged to wheel for others. Gardiner, PG&E, Tr. 243, 248; SCE, #3-187, p. 20.

On the other hand, the municipal utility of Vernon, California, which lacks an interest in the Intertie, supports a section 5(d) review of alleged California anti-competitive practices. Vernon states that it has been denied access to the Northwest nonfirm energy market because of the ownership control of the southern portion of the Intertie. "Vernon is unable to obtain access even to the unused Intertie transmission ordered by the Administrative Law Judge in FERC Docket No. E7777." Vernon, #3-80, p. 2.

Among Northwest utilities, some oppose any change from pro-rata allocations during all conditions. WWP asserts that pro-rata allocations are consistent with existing law and ensure widespread use of the Intertie among all Northwest generators. WWP, #3-122, pp. 22-23.

PSP&L argues that the Exportable Agreement has allocated Intertie capacity since the construction of the Intertie. It "cannot now be argued that such an allocation was unlawful at the outset." PSP&L, #3-193, p. 2.

ICP and PGP also support allocating pro-rata shares of Intertie capacity to scheduling utilities. ICP, Tr. 374; PGP, #3-194, p. 8.

Other Northwest utilities specifically addressing section 5(d) support the provision. PGP applauded BPA's effort to go to a free and open market after construction of the third AC line. PGP, Tr. 384. PPC also supports section 5(d). PPC, #3-125, p. 5.

C. <u>Analysis and Decision</u>

California and the Northwest each claim support -- in statutes, legislative history and Congressional acquiescence -- for pro-rata allocations that the other labels "anti-competitive." In California, a similar debate has continued since 1973 before the Federal Energy Regulatory Commission and Federal district court between Intertie "haves" and "have-nots." At least regarding the LTIAP, it is time to end the stand-off by attempting some practical resolution of problems that trouble both regions. Attempts at a solution should not await commercial operation of the third AC line.

We begin this analysis with the opinion in <u>California Energy Commission v. BPA</u>, 831 F.2d 1467 (9th Cir. 1987). The court instructed us to develop a policy, from proposals advanced during this proceeding, that is predictable, fair and nondiscriminatory while ensuring adequate BPA revenues. 831 F.2d at 1476-77. We must consider antitrust policies in deciding how to allocate Intertie capacity. "This need to consider the interests of preserving competition, however, does not override BPA's statutory obligations, repeatedly expressed in 16 U.S.C. §§832f, 838g, and 839e(a)(1), to be fiscally self-supporting." <u>Id</u>. at 1475. This is a practical test, not a requirement that we strive for a theoretical ideal unworkable on a day-to-day basis.

CPUC cites <u>California Energy Commission</u>, 831 F.2d at 1475, for the proposition that "Congress specifically articulated its intent that BPA operate its transmission lines in part 'to prevent the monopolization thereof by limited groups.'" CPUC, #3-199, p. 3. To the extent this passage applies to transmission, we believe it relates with equal force to practices on California's portion of the Intertie, at least to the extent necessary to protect BPA revenues. Tr. 226-29.

<u>BPA concerns about California Intertie practices</u>. We continue to be concerned about California practices that affect the price of spot-market energy sold over the Intertie. These practices affect our revenues directly by lowering our prices of spot-market energy below levels that would prevail in a competitive market. Indirect revenue effects flow to BPA when lower spot-market prices cause Northwest nonfederal utilities to reduce their purchases of firm power from us or request higher residential exchange payments. 17/

We have been asked by California utility representatives to identify the practices among California Intertie owners that offend us and that we label "anti-competitive." Tr. 226, 230. We are troubled by pro-rata allocations in the Southwest that allow California Intertie owners to avoid sharing unutilized Intertie capacity among themselves or with the California "have-nots." We believe it economically unjustifiable for a California Intertie owner to leave portions of its share unutilized, even though other owners or nonowners have need for additional spot-market purchases from the Northwest. California Intertie practices suppress the price BPA and other Northwest suppliers can receive for their spot-market energy products. 18/

Pro-rata allocations under various Intertie access policies have always been intended to mirror and offset pro-rata allocations in the Southwest. California commenters argue that pro-rata allocations under the LTIAP tend to stabilize prices at levels higher than where sellers may increase their total

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17/ Some California commenters suggest that the sensitivity analyses released in February 1988 overstate the indirect revenue impacts on BPA. On the other hand, the DFI appendix to PG&E's comments suggests that Northwest displacement market losses could be four to seven times greater than we estimated. See pp. 55-56, above. The important point is that BPA lost $200 million during the last fiscal year and any change from present Formula Allocation procedures will diminish our revenues and increase our costs. We are not willing to dismiss as insignificant residential exchange cost increases of up to $6 million and Northwest displacement market losses of $6-to-$40 million per year. See footnote 16, above.

18/ Our concern about prices received by other Northwest sellers relates to the indirect revenue effects this has on BPA.

sales by reducing prices. It is equally logical to conclude that pro-rata allocations of California Intertie capacity suppress prices below levels that would prevail in a market where more buyers bid independently. 19/

This concern should not necessarily be read as a demand that Intertie capacity always be made available at cost-based transmission rates. The benefits of a Northwest energy purchase can be shared between wheeling and purchasing utilities. This is something we thought we had helped facilitate through the Western Systems Power Pool experiment. See Pacific Gas & Electric Co., 38 FERC ¶61,242 (1987). However, we do not believe that the promise of that experiment has been fulfilled.

Much of the discussion about California Intertie practices has focused on the supplemental letter agreement to the Memorandum of Understanding ("California Letter Agreement") among California utilities proposing to own and construct the third AC transmission line. Tr. 230. The California Letter Agreement establishes a pro-rata allocation methodology among all California Intertie owners -- new and existing -- after the third AC transmission line goes into commercial operation:

> In order that many California consumers share in the benefits of federally generated power, and in consideration of the benefits received by interconnection with the existing AC Interties (the Project and the two presently existing 500-kV Intertie lines), the Participants ... agree, in times when Bonneville Power Administration is allocating non-firm energy for export out of the Pacific Northwest and the availability of such energy is less than the total available transfer capability in the then-existing Interties (including the Project), that said Participants will share in the limited availability of such energy on a pro rata basis according to their respective allocations on all AC Interties. [Emphasis supplied.]

19/ We know that California Intertie owners have nonfirm wheeling arrangements with certain nonowners. The problem we hear repeatedly from nonowners, however, is that these arrangements are so cumbersome as to be unworkable in any practical sense. E.g., Vernon, #3-80, p. 23. Nonfirm wheeling made available to California "have-nots" on 15 minutes' notice has little practical value. In contrast, BPA preschedules nonfederal usage of the Northern Intertie 24 to 72 hours in advance.

The agreement divides the market for BPA energy among California utilities during Condition 3 and, sometimes, Condition 1. Tr. 226. The language of the California Letter Agreement suggests that no California utility would have an incentive to bid up the price for BPA energy, even to the FERC-approved rate of 18 mills/kwh, because no one could increase its pro-rata share.

If this language in the California Letter Agreement reflects the signatories' intent, there would be little reason for BPA to cease pro-rata allocations under Conditions 2 and 3. Doing so would simply lessen the chances of recovering <u>on average</u> the cost of our energy. During public meetings on the 1987 draft policy, no signatory seemed able to explain the effects of this agreement on competition. Tr. 236. Our questions about phrases such as "allocating non-firm energy for export" remained unanswered until PG&E filed its written comments.

Our understanding of the California letter agreement is now based on the written representations of PG&E (#3-188, p. 26), confirmed through informal discussions with PG&E, TANC, SCE, LADWP and CEC. According to these utilities, the letter agreement is intended by its signatories to neutralize the public preference requirement that we sell spot-market energy first to publicly owned utilities and cooperatives. The agreement applies only to BPA sales when our available energy is less than Intertie capacity and "only at times when BPA itself is allocating this energy among buyers on some basis other than price, i.e., selling all of it at one price." PG&E, #3-188, p. 26.

We express no opinion on the validity or wisdom of this agreement. However, California does claim that, if BPA offers energy at more than one rate (or under a share-the-savings rate), nothing in the California Letter Agreement will inhibit our ability to sell to the high bidder. TANC has represented that public preference would allow it only a first right of refusal to BPA energy priced at the high bid.

However, no such benign interpretation is possible for section 7.02 of the "California Companies Pacific Intertie Agreement" (California Intertie Agreement), between PG&E, SCE, and SDG&E. 20/ In fact, California disclaimers about the California Letter Agreement only heighten our concern about section 7.02. This provision applies across-the-board to all Northwest sellers, not just to BPA, for all types of spot-market and firm transactions, whether a single price or multiple prices are offered. Because it is an agreement among investor-owned utilities, it cannot possibly be construed as rectifying some perceived imbalance among them caused by public preference laws.

Section 7.02 creates a pro-rata allocation among these three utilities that inhibits price competition in California. The requirement that "[e]ach Company shall have the right to purchase its share, based on Relative Size Percentages, of any Northwest Power acquired by any one or more of the Companies, on the same terms and conditions as the acquiring Company" means

20/ The provision reads: "7.02 Northwest Power

"Each Company shall have the right to purchase its share, based on Relative Size Percentages, of any Northwest Power acquired by any one or more of the Companies, on the same terms and conditions as the acquiring Company. However, consistent with the principle stated in the first paragraph of Section 6, the Coordination Committee shall make studies and recommendations regarding the reallocation of such Northwest Power, if necessary, to provide maximum equitable benefits to all the Companies. If any Company rejects all or part of the Northwest Power so made available to it, the other Companies shall have the right to share the rejected amount in the ratio of their Relative Size Percentages; provided, however, that the rejecting Company shall retain the right to recapture the power rejected by giving written notice five years in advance of the date when the recapture is to become effective, which recapture date shall not be earlier than twelve months after the accepting Company or Companies began taking such power. Before any Company may assign or transfer all or any portion of its Northwest Power to a non-Company entity, such Company must first offer it to the other Companies in the ratio of their Relative Size Percentages on terms and conditions no less favorable than those on which it is then purchasing such Northwest Power. If one of the Companies rejects all or part of such offer, the other shall have a right to accept all or a part of the rejected amount."

that the price and quantity of every Northwest or BPA offer to sell spot-market energy can be communicated from PG&E to SCE to SDG&E. Any competitive motivation to bid up the price is counteracted by the fact that no utility is entitled to any more than a pro-rata share. Why would any buyer bid up the price if the amount of its purchases cannot increase? In effect, these three "competitors" act as a single dominant buyer of Northwest energy.

Elsewhere in section 7.02, parties to the California Intertie Agreement are accorded a first right of refusal over power from the Northwest. No California "have-not" may gain access until this right has been satisfied.

Section 7.02 of the California Intertie Agreement goes beyond the protection of private-property interests that the California investor-owned utilities hope to protect -- and which we have no intention of overturning. To borrow a criticism from SCE, the California Letter Agreement is, "by design, the death of price competition on the Pacific Intertie." SCE, #3-187, p. 15.

Section 7.02 has been found "anticompetitive, unjust and unreasonable" by a FERC administrative law judge. Pacific Gas & Electric Co., 26 FERC 63,048, p. 65,215 (1984). This provision is one we refer to when we complain of a California monopsony that affects us directly through our own spot-market sales and indirectly through cost consequences associated with Northwest utility sales to California.

SCE has asked with regard to Northwest energy that Intertie "transactions be prioritized through natural pricing with the least expensive energy used first." SCE, Tr. 436. However, this is only half the definition of an economically efficient power market. The least-expensive supply (the low offer in the Northwest) should be matched against the most-expensive displaceable resource in California (the high offer in California). Intertie restrictions embedded in section 7.02 of the California Intertie Agreement eliminate the possibility of SCE's "natural pricing" in the Southwest.

A new concern relates to a recent agreement between PG&E and Turlock Irrigation District under which PG&E has agreed to transmit energy from several different California utilities. Notably absent is an offer to transmit energy from BPA or other suppliers in the Northwest. The agreement indicates that PG&E will make power available from a variety of load-control areas in California, but not from the Northwest. We intervened in the regulatory proceeding on this agreement; however, FERC chose not to address the issue of PG&E's restriction on access to Northwest markets. 21/

These are our major concerns. They are shared by others in the Northwest and by California "have-nots." However, we would be remiss in stating our concerns without also proposing a way of resolving differences with our California customers. Section 5(d) has been rewritten to provide for an experimental period of 18 months during which we will cease making individual allocations to nonfederal utilities during Conditions 2 and 3. This experiment, which does not await commercial operation of the third AC line, is described as follows.

Experimental allocations. This experiment will commence only after the scheduling requirements, described below, have been developed. Then, during the 18 months of the experiment, Condition 2 and 3 procedures will be modified to exclude individual utility allocations.

Under Condition 2, when the declarations of BPA and Northwest utilities exceed available Intertie capacity, we would make a pro-rata allocation to BPA and leave the remaining block of Intertie capacity available to Northwest

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21/ See Pacific Gas & Electric Co., 42 FERC ¶61406 (1988).

utilities as a whole. Each Northwest utility could then compete to make sales to Southwest utilities -- with no assurance of any individual allocation.

Under Condition 3, when the declarations of BPA and Northwest utilities are less than available Intertie capacity, we would again make a pro-rata allocation to BPA and a block allocation for competition among Northwest utilities. U.S. extraregional utilities and then Canada could compete for remaining Intertie capacity. During Condition 3, we would expect significant competition whenever the size of the California market was less than Intertie capacity.

New scheduling requirements. Neither we nor participating utilities should rush head-long into this experiment. Before the experiment begins, our schedulers must resolve significant technical questions. To be effective, section 5(d) would require cooperation from all utilities involved. BPA and participating utilities would need a communications network to exchange current -- possibly instantaneous -- information on Intertie availability for both the Northwest and California segments. This information would include the unpurchased allocations by the hour for BPA, nonfederal utilities, extraregional utilities under Condition 3, and availability of the California Intertie -- disaggregated by owner. We have not yet estimated the cost of participating in the communication system. These technical concerns will be addressed in informal sessions following implementation of the LTIAP.

We must also develop a replacement for the pro-rata allocation system to determine which utilities receive Intertie capacity during particular hours. One possibility might be to preschedule transactions on a first-come, first-served basis until the total nonfederal allocation is exhausted. Another option might be to develop an open bidding system for nonfederal spot-market usage of the Intertie. A bidding system could be the economically optimal way of allocating demand for a limited transmission resource. It would tend to encourage transactions between sellers with the lowest incremental-cost resources and buyers with the highest decremental-cost resources. Use of a bidding system to allocate Federal Intertie capacity has been advocated by PG&E. E.g., comments on the draft IDU EIS, pp. 7, 17, (January 14, 1988). Revenues produced by such a bidding system would diminish the revenues lost by making the Intertie available to others, thereby providing us with a new source of funds with which to repay the Treasury.

Review. Our most significant measure of the success of the section 5(d) experiment will be increased Northwest sales to California utilities that lack ownership or contractual interests in the California portion of the Intertie. We expect that Intertie practices in the Southwest will have to change so as not to restrict the market for Northwest energy in California. We are especially concerned that California utilities bid independently for Northwest spot-market energy, refrain from sharing information about pricing and quantities, and not reallocate the power purchased over the Intertie since this would negate any benefit provided by the experimental mechanism.

Our objective will be to remove provisions, like section 7.02 of the California Intertie Agreement, which limit opportunities for Northwest utilities, including BPA, to sell energy to any willing buyer in the Southwest. If this is to occur, parties to coordination or wheeling agreements among California utilities, such as the one between PG&E and Turlock Irrigation District, must be willing to amend such contracts to provide access for BPA and other Northwest resources at terms no less favorable than those provided to any other bulk power supplier.

We anticipate that Turlock, Anaheim, and other "have-not" utilities will have incentive to bring restrictive agreements to light once the LTIAP is implemented. As we analyze the success of the section 5(d) experiment, it will not be a credible response for California Intertie owners to cite to wheeling or coordination agreements so cumbersome or restrictive that access to Northwest markets is rarely, if ever, provided to the "have-not" utilities.

We will also review effects of the experiment on smaller utilities in the Northwest. Utilities such as EWEB have expressed concern about policy changes that could affect their ability to make spot-market sales.

We will analyze the success or failure of the experiment throughout its term. Utilities, regulators, and other interested parties will be encouraged to express their views in writing and through informal discussions. Public comment will be invited. At least 30 days before the experiment ends, we will issue a written report on whether to make the experiment permanent. 22/

It is our hope that section 5(d) -- or an improved version thereof -- will be maintained at the end of the 18-month test. Critical to our determination, however, will be the willingness of California utilities and regulators to promote a competitive market in the Southwest.

Comparison to other proposals. As noted above, the section 5(d) experiment corresponds to the position of the CEC and CPUC during review proceedings in California Energy Commission v. BPA, 831 F.2d 1467, 1475 (9th Cir. 1987). It is also similar to one of the alternatives advanced by PG&E during this proceeding. The differences are explained here.

First, extraregional utilities do not receive Condition 2 access under section 5(d). Our reasoning for this distinction was explained earlier in this decision. However, during the course of the experiment, we anticipate that negotiations contemplated by section 6(b) of the LTIAP will proceed. If BPA and BC Hydro reach agreement on increased coordination of the two Columbia

22/ In the IDU EIS analyses, the "Pre-IAP" and "Proposed" allocation methodologies have essentially the same environmental consequences. Therefore, BPA has no environmental reservations about the experimental elimination of individual allocations for nonfederal utilities in Conditions 2 and 3.

watershed systems, BPA might then be able to provide Condition 2 access to this extraregional utility. We take this prospect quite seriously.

Second, pro-rata allocations continue during Condition 1. This element seems less critical to California alternative proposals. PG&E's comments expressly provide that Condition 1 allocations be maintained. PG&E, #3-188, p. 35. CEC's first alternative proposal would permit pro-rata allocations -- or even the complete exclusion of nonfederal sales -- whenever prices were at or below our cost-based nonfirm energy rate. CEC, #3-218, attachment 1.

Retention of Condition 1 allocations is crucial to the enforcement of the Protected Area provision, described below. The Condition 1 decrement will provide an effective reason for utilities to refrain from building or acquiring hydro projects located in protected areas. The decision in California Energy Commission v. BPA makes it clear that we should take our fish and wildlife responsibilities as seriously as antitrust policy and other concerns. This policy balances our numerous statutory obligations.

Also, retention of Condition 1 allocations gives every nonfederal utility some assurance of Intertie access when hydrological conditions might otherwise force them to spill. This was a critical concern of Northwest utilities, particularly the public generators. Tr. 386.

Third, section 5(d) makes no reference to share-the-savings pricing, which seems critical to the PG&E proposal. The fact that we are not resolving any pricing issues in this proceeding should not be read as a bias against share-the-savings. As explained later in this decision, we are open to the latest California suggestion regarding this pricing methodology.

Responding to other alternatives, neither of CEC's two proposals can be adopted. The first alternative, "restricted competition below cost," is far less competitive than any other proposal under consideration. It would give us complete control over spot-market Intertie transactions whenever we set our price at or below the cost-based rate we ourselves determined in the preceding BPA rate case. For reasons described earlier in this decision (pp. 52-54), this proposal carries serious "market manipulation" overtones. Ironically, this alternative seems inconsistent with the court's holding in the review proceeding initiated by CEC.

The second CEC alternative, "annual reconciliation," is well-intended but impractical. It would require us to monitor the relative benefits of nonfederal sales to California. We do not know the prices of these sales, not to mention resource cost information for both buyer and seller. Also, this approach would simply maintain controversy between BPA and California as an annual event. See pp. 54-55, above. The theory behind CEC's second alternative could be implemented on a more practical basis if the Northwest and California can reach a consensus on share-the-savings pricing. We take up share-the-savings in the next section of this decision.

Finally, we respond to PG&E's "fully competitive when not spilling" proposal for Formula Allocation. The observations we expressed on p. 55-57 of this decision are pertinent here. This proposal is an overkill solution to the problem PG&E alleges. By PG&E's own study (corrected to include residential exchange burdens), it would cause BPA to lose up to $80 million per year to correct the problem attributed to pro-rata allocations. This would expose to excessive risk our responsibility to be "fiscally self-supporting." California Energy Commission v. BPA, 831 F.2d at 1475. In contrast, PG&E's "BPA-first" alternative is a more revenue neutral proposal which resembles the final section 5(d) we are adopting.

Section 3. Other Issues

ISSUE NO. 1: **Should BPA renew efforts to establish share-the-savings pricing for spot-market transactions with Northwest and California utilities?**

REFERENCE: **This issue is not addressed in the policy.**

A. Proposal

BPA's SS-87 share-the-savings rate is an alternative schedule available to any utility purchasing nonfirm energy from BPA. We make no new share-the-savings proposal in this proceeding. Resolution of ratemaking issues would be undertaken only in proceedings under Northwest Power Act section 7(i).

Several California utilities and regulators advocated share-the-savings pricing during informal discussions with BPA staff and again in their written comments. They believe that widespread adoption of this rate form might lessen the need for Formula Allocations under the IAP.

BPA endorses the concept of share-the-savings pricing and is willing to proceed towards widespread adoption of such a rate. While BPA is committed to exploring this pricing mechanism in good faith with California utilities, everyone should be aware that BPA has attempted unsuccessfully to implement these rates in the past with the same utilities.

B. Summary of Comments

Much of the discussion about this matter occurred during the extensive informal discussion phase of this proceeding. Among utilities that submitted written comments, SDG&E suggests that the LTIAP should give priority allocations to spot-market sales made pursuant to share-the-savings rates. SDG&E, 3-196, p. 3.

PG&E takes the lead on share-the-savings pricing in its written comments. Each of the alternative proposals discussed in the body of its comments and in the DFI appendix rely on this pricing mechanism.

SMUD supports the concept of such a rate "as the basis for establishing Northwest surplus non-firm energy rates." It does not support the use of a "share the savings rate formula as the basis for allocation of Intertie access." SMUD, #3-183, p. 4.

WAPA also encourages BPA to include "permissive language in the LTIAP that would allow adoption of this concept." WAPA, #3-189, p. 3.

Unlike other California parties, TANC does not support a provision in the final LTIAP that allows for a reassessment of the policy if a share the savings rate is developed. TANC states:

> TANC does not agree with the suggestion put forward ... that the development of a share-the-savings rate is relevant to an allocation process for Intertie capability. Our concern is that if a share-the-savings concept were developed and coupled with Intertie access on the basis of matching lowest incremental cost power in the Northwest with highest decremental cost utilities in the Southwest in an effort to maximize benefits, then utilities in the Southwest with lower decremental costs such as TANC's members would risk not being able to access their own share of the Intertie. [TANC, #3-183, p. 2.]

From the Northwest, only DSIs offered comments on this question. During the public meeting of January 27, 1988, Mr. Durocher suggested that we again consider a share-the-savings approach to spot-market pricing. Tr. 823.

C. Response

We have stated a commitment to work toward implementation of share-the-savings pricing. However, to put this issue in perspective, it is wise to discuss the history of this rate form as a BPA pricing mechanism.

Between 1965 and 1974, the nonfirm rate to California was 2.0 mills per kWh, reflecting a static sharing of benefits between the Northwest and California's displaced 4.0 mill/kWh oil-fired generation. When California's oil costs rose to 15 mills/kWh, BPA increased its nonfirm energy rates to 3.0 mills/kwh in 1974. By 1979, when BPA adopted its "H-6" rate, California's alternative cost of oil-fired generation was between 30 and 40 mills/kwh.

The H-6 rate schedule incorporated a share-the-savings rate. The thermal displacement rate was based on both value-of-service and cost-of-service considerations. It allowed BPA to react to market and water conditions affecting maximum displacement of thermal resources both inside and outside the Northwest. It was priced at 50 percent of the buyer's decremental costs if the buyer purchased the power directly for use on its system or 33 percent of the buyer's displaced costs if the power was purchased indirectly through any Northwest utility. The rate for other sales was based on results from a cost-of-service analysis.

While we were considering adoption of the H-6 rate in 1979, legislation leading to the Northwest Power Act was debated in Congress. California utilities took the opportunity in Congressional hearings to protest the share-the-savings proposal in the H-6 rate because it was not cost-based. These utilities offered language that would have prohibited BPA from utilizing share-the-savings rates. <u>See</u> Pacific Northwest Power Planning, Hearings before the Subcommittee on Energy and Power, House Committee on Interstate and Foreign Commerce, 96th Cong., 1st Sess., pp. 338-414 (1979). Congress rejected the utilities' substantive amendments and adopted procedural requirements for nonfirm rates found in Northwest Power Act section 7(k).

We adopted the H-6 rate for a two-year period. Although BPA had projected an average rate of 8 mills/kwh, California utilities actually purchased nonfirm energy at an average rate of 7.1 mills/kwh -- displacing their 30-40 mill/kwh oil-fired generation. U.S. Department of Energy, Bonneville Power Administration, 23 FERC ¶61,342, 61,739 (1983).

In 1981 and 1982 BPA adopted cost-based rates for nonfirm energy which did not contain share-the-savings components. When these rates were reviewed by FERC, the Northwest utilities argued that BPA should have based its NF-1 and NF-2 rates on share-the-savings. However, California utilities and regulators opposed this suggestion and argued that a share-the-savings rate was unlawful.

FERC's administrative law judge found that a flexible share-the-savings rate could match market demands with the costs of supplying nonfirm energy. The judge held that there were no statutory limitations on the use of this type of rate. However, because BPA had not proposed it, no further consideration was required. U.S. Dept. of Energy - Bonneville Power Administration, 29 FERC ¶63,039 (1984). The Commission also declined to address the merits of share-the-savings rates. See 36 FERC ¶61,335 (1986).

In 1985, we adopted an experimental share-the-savings rates for sales of nonfirm energy. The "SS-85" rate had two components: an economy energy rate and a displacement rate. Purchasers whose decremental costs were equal to or greater than 24 mills/kwh purchased nonfirm energy under the economy energy rate at one-half their decremental cost plus six mills/kwh. Displacement rate purchasers had decremental costs less than 24 mills/kwh and purchased nonfirm energy according to a formula of the greater of 75 percent of decremental cost or 11 mills/kwh. Most Northwest utilities endorsed the SS-87 rate, while California utilities and regulators objected on statutory grounds.

In the spring of 1986, however, we initiated contract negotiations with the Los Angeles Department of Water & Power and Pacific Gas and Electric Company to explore their interest in an SS-85 contract. Although these discussions were informative, no contracts were executed.

In the summer of 1986 BPA continued informal discussions with California regulators concerning nonfirm rate "predictability." We conducted two workshops devoted to the share-the-savings pricing concept. It was our intention that the workshop would produce information useful in developing a new share-the-savings rate in 1987.

In 1987, BPA proposed a new share-the-savings rate, "SS-87." For the first time on the record, a California utility expressed an interest in a BPA share-the-savings rate. Pacific Gas and Electric Company supported a rate based on a 50-50 split of the seller's incremental costs and the buyer's decremental costs. BPA adopted an experimental SS-87 rate based on a formula to be negotiated between the buyer and seller subject to floor and ceiling prices. To date no sales have been made under this rate.

California Public Utility Commission claimed during our 1987 rate case that share-the-savings pricing was illegal -- for BPA. However, in testimony before the House Subcommittee on Water and Power, CPUC president Stanley Hulett stated that California utilities were interested in pursuing the development of BPA share-the-savings rates. Oversight Hearing on Intertie Access Policy of the BPA: Hearing before the House Subcommittee on Water and Power Resources of the Committee on Interior and Insular Affairs, Part 1, p. 264 (May 7, 1987).

Share-the-savings rate implementation is also complicated by regional and public agency preference laws. Against the mainstream Northwest position, Puget Sound Power & Light Company has maintained that a share-the-savings rate would violate the Northwest Preference Act. Of course, regional preference pertains only to the allocation of power and not to some preferentially low price, Central Lincoln PUD v. Johnson, 735 F.2d 1101, 1125 (9th Cir, 1984).

To sum up, we have had considerable experience negotiating share-the-savings rates with utilities simultaneously attempting to preserve litigation positions that BPA cannot offer such a rate. However, we are willing to try again if the legal posturing can be kept from interfering with practical issues about implementing such a rate. BPA continues to believe that this kind of rate promotes economic efficiency and equitable sharing of benefits of spot-market energy transactions.

ISSUE NO. 2: **Should utilities with unused contractual or ownership rights to non-BPA transmission facilities be allowed access to BPA's portion of the Intertie regardless during Condition 3?**

REFERENCE: **1987 draft policy §3(d)**
Final LTIAP §3(d), §5(c)(3)

A. BPA Proposal

The use-own-first provision in the 1987 draft required that utilities owning or controlling access to the Intertie fully utilize their transmission capacity prior to being allowed access to Federal capacity for spot-market sales. 23/ Tr. 14.

B. Summary of Comments

During the public meetings in January 1988 and in the comment letters we received no specific comment on this issue. However, in informal meetings PP&L, one of the two present Intertie owners, suggested that the use-own-first provision not apply during Condition 3 when available Intertie capacity

23/ This policy also applies to Assured Delivery service, discussed below.

exceeds the sum of Northwest utilities' declarations. They maintain that under this condition utilities without ownership or control of Intertie capacity to California are not impacted by allowing owners to use the facility.

C. **Analysis and Decision**

The purpose of the use-own-first provision is to provide equitable access to Northwest utilities to a scarce resource. Utilities should use their own Intertie rights before using the Federal portion of the Intertie. Under Conditions 1 and 2 Northwest demand exceeds available Intertie capacity. Therefore, in order to maintain a sense of equity an Intertie owner must use its own Intertie first. This argument is not as strong under Condition 3, as Intertie capacity meets the demand of all Northwest utilities. We concur with PP&L that allowing access to any utility regardless of ownership status during Condition 3 will not deprive other utilities of Intertie capacity.

ISSUE NO. 3: Should the LTIAP incorporate a mechanism to dispatch the Northwest's coal-fired generating units on the basis of sulfur dioxide emissions?

A. **BPA Proposal**

The 1987 draft policy did not address this issue.

B. **Summary of Comments**

Northern Plains Resource Council, the Idaho League of Women Voters and the Northwest Conservation Act Coalition suggested that we use the LTIAP to force Northwest coal-fired generating units to be dispatched in inverse order to their sulfur dioxide (SO_2) emissions. The Conservation Act Coalition suggested that this alternative may be more economic than the way coal plants have been dispatched.

C. Analysis and Decision

Unlike the protected area concept which focuses on hydro projects yet to be constructed, SO_2 dispatch would involve us in the day-to-day operations of several existing coal plants in which we have no financial interest. Also, the protected area concept is attractive because it focuses directly on hydro development that could jeopardize our statutory investments in fish and wildlife. In contrast, Congress has not made our ratepayers a source of funds for air-quality improvements and we are not inclined to use the LTIAP as a mechanism for enforcing a well-intended, but impractical, SO_2 dispatch idea.

We performed an analysis to examine how a change from economic dispatch to SO_2 dispatch might affect Northwest export sales. See IDU EIS, Vol. 2, pp. 1-20 through 1-22. In this analysis, Northwest coal-fired plants were ranked on the basis of their average SO_2 emissions per kwh. The rankings were taken from "Burning Coal For Export: Environmental and Economic Dimensions of Northwest Intertie Sales to California" by Robert Watson, NRDC.

The plants were then dispatched in order of increasing SO_2 emissions per unit of electrical energy produced. The Colstrip plants had both the lowest costs and the lowest SO_2 emissions per kwh. They were dispatched first. Valmy Units 1 and 2 have the second lowest SO_2 emissions per unit of electrical energy produced, but their costs are second only to Boardman. The SO_2 dispatch model blocks market access to other lower-cost coal plants in the Northwest. California buyers, who seek the lowest price, purchase less Northwest energy under SO_2 dispatch than under economic dispatch.

SO_2 dispatch generally caused reservoir levels to decrease. Of the four years analyzed in the IDU EIS, the largest decrease and the greatest impacts occurred in 1988. The greatest impacts were at Hungry Horse reservoir in the fall and winter months. Lower levels could harm resident fish and recreation.

Ideally, an "environmental dispatch" would consider all types of impacts, not just SO_2 emissions. Ranking generating resources of different types on the basis of their total environmental costs would require considerable effort and be fraught with controversy.

Further, for environmental dispatch to be feasible, there must be some mechanism for keeping power from Northwest generators competitive with California and Inland Southwest sources of power -- which are not similarly constrained. Some agreement among utilities would be necessary to ensure that owners of lower-cost plants would still recover their investments in plants operated less frequently. Owners of higher-cost, cleaner plants would have to be able to recover their costs and receive a return on their investments even though the price of power sold from their plants might be too low to do so. We could not implement such arrangements unilaterally through the LTIAP.

Also, we might be forced to attempt some tracing of power from a generating unit to the Intertie -- the LTIAP would not necessarily have an effect on power utilized within the Northwest. Yet, that would raise questions about whether units with high emission levels were being used within the Northwest so that "cleaner" resources could be exported.

This proposal is laden with complexities which the commenters have not addressed. Because of these complexities and the limitations of what we can accomplish through the LTIAP, we will not attempt to effect an SO_2 dispatch of resources. Such a proposal, if practical at all, could only be accomplished through a cooperative effort undertaken by coal-plant owners.

PART THREE

TRANSMISSION CAPACITY AVAILABLE FOR LONG-TERM FIRM TRANSACTIONS OF NONFEDERAL UTILITIES

"ASSURED DELIVERY"

Section 1. TOTAL INTERTIE CAPACITY MADE AVAILABLE

ISSUE NO. 1: **How much Intertie capacity should BPA reserve for Assured Delivery transactions?**

REFERENCE: **1987 draft policy §4(d)(1)**
Final LTIAP §4(c)(1)

A. BPA Proposals

Under the LTIAP, "Assured Delivery" means firm Intertie transmission service provided under a BPA transmission contract to wheel power covered by a long-term firm contract between a Northwest scheduling utility and a Southwest utility. The Interim and Near-Term policies did not provide for Assured Delivery service. Then, in the 1986 draft LTIAP, we proposed to set aside a maximum of 420 MW to be devoted exclusively to the long-term firm power sales of Northwest scheduling utilities. The capacity limit was based on the then-current Pacific Northwest Utilities Conference Committee (PNUCC) forecast of firm power surpluses for each Northwest generating utility.

The 1986 draft policy reflected our conclusion that we could best serve the firm transmission needs of Northwest utilities by facilitating long-term sales of their surplus firm power to the Southwest. We concluded then that nonfederal Northwest utilities, like BPA itself, were primarily interested in new long-term firm power contracts with California.

Before the 1987 draft policy was released, we conducted an informal survey of Northwest utilities to determine their needs for firm transmission. They increased our awareness that the long-term commodity market consists of more than firm power sales. The prevailing view expressed to BPA staff was that the transmission usage of choice was for seasonal exchanges -- firm transactions that take advantage of seasonal diversity between Northwest and Southwest loads through transfers of firm power from north to south during the Southwest's summer load season and from south to north during the Northwest's winter load season. Tr. 5. However, there was also a strong minority opinion -- espoused principally by MPC, Tacoma, and Cowlitz PUD -- that firm power sales should continue to be accommodated.

In the 1987 draft policy, we increased the limit on Assured Delivery capacity from 420 MW to 800 MW. We divided that capacity between 444 MW available for wheeling firm power sales and 356 MW available for seasonal exchanges.

The 444 MW limit was based on the most recent PNUCC firm surplus forecast and a continuation of the Tacoma and Cowlitz agreements with WAPA. However, we increased the individual number for MPC from 80 MW to 105 MW as part of a proposed settlement to resolve any claims of MPC against BPA under Northwest Power Act section 9(i)(3), 16 U.S.C. 839f(i)(3). Tr. 6. If this settlement -- which has been encouraged by many Northwest utilities -- is concluded, <u>Montana Power Co. v. BPA</u>, 9th Cir. No. 86-7330, will be dismissed with prejudice.

The new capacity limit carried two qualifications -- one expansive, the other limiting. First, we committed to reassess this number to determine the amount of any additional Assured Delivery capacity when the third AC interconnection was placed in commercial operation. This offered the prospect of additional firm wheeling capacity when the physical capacity of the Intertie increased to 7,900 MW. Second, the 800 MW limit was also made subject to possible reduction if the DC terminal expansion project was not completed on schedule. These qualifications reflected a note of caution about possible BPA revenue losses under new features incorporated into the 1987 draft policy. We would prefer to test the final policy at the 800 MW limit before committing to any larger amount. Tr. 109.

800 MW Cost Analysis. We studied the lost revenues associated with providing capacity on a long-term basis for Assured Delivery of both firm sales and exchanges. This study was provided during the public meetings in January 1988 on the LTIAP. The analysis was done with the Systems Analysis Model (SAM). For the purpose of the study, Assured Delivery contracts were assumed to begin in 1989 and terminate in 2006. Two alternatives were studied: the first included the MPC firm power sale of 105 MW and 695 MW of seasonal exchanges; the second included the MPC 105 MW firm power sale, 440 MW of seasonal exchanges, and 255 MW of sales of other firm surplus power. The second alternative represents the more likely case under the policy, since we are setting aside 444 MW for potential firm sales including the MPC transaction. We anticipate that part of the 444 MW of capacity set aside for firm power sales will be utilized for exchanges.

The exchanges in the study were considered to be seasonal with energy flowing south in June through October and returning north during November through March. With the exception of the MPC firm power sale, the firm surplus sales were shaped 1.8 times the allowed capacity during the months of September through December.

In preparing the final LTIAP, BPA staff worked within the SAM study's second alternative in determining the effects on revenues. We estimated the load factor for seasonal exchanges to be 50 percent. However, we chose not to include BPA's estimate of lost revenue due to lost firm capacity sales. This decision was made because of the uncertainty of BPA's market efforts in this area. However, we can be relatively certain of the impacts on our nonfirm sales as a result of the LTIAP.

The analysis includes a calculation of mitigation impacts. These were based on the proposed Condition 1 mitigation and restriction on seasonal exchange cash-outs. All returns were assumed to be at COB/NOB. For all north to south deliveries, under Condition 1 in the study a utility's Formula Allocation was reduced by the amount of its Assured Delivery. If the Formula Allocation was insufficient to cover the entire amount of its Assured Delivery contract, the utility was assumed to purchase the difference from BPA. The value of mitigation is estimated by determining the amount of overgeneration spill in megawatts up to 60 percent of the Assured Delivery under Condition 1. These megawatts are priced at the average price of Condition 1.

For all south-to-north deliveries during Conditions 1 and 2, we assumed BPA would receive revenues equal to 60 percent of the incremental benefits associated with serving the increased winter market. BPA's revenue protection due to mitigation is estimated to range from $62-$107 million depending on the alternative.

We assumed that if the system is constrained by supply there would not be any harm to BPA as a result of firm power sales. At all other times, BPA's loss is estimated to be 60 percent of the lost secondary revenues. In the case of exchanges, the study assumes that without mitigation we would incur 60 percent of the lost secondary revenues under all conditions during the summer and that BPA does not serve any of the increased winter return market.

Wheeling revenues were included in the consideration of net impacts on our revenues. Some commenters felt that BPA should not have to include the wheeling revenues in the calculation of the net impact. Without this calculation the net impacts would have been $154 million larger.

Without the mitigation, the net estimated revenue impacts, including lost nonfirm revenues and PF sales and the increase in wheeling revenues, was

$200 million. After mitigation the net estimated revenue impact was $118 million, or an annual impact of approximately $9 million.

The following table is from the March update to the January SAM study already made available. (Wheeling revenues were revised in the update.)

ASSURED DELIVERY ANALYSIS
(from March 1988 revised SAM study, Table 5)

105 MW MPC Power Sale
440 MW Seasonal Power Exchange@50%
255 MW Firm Surplus Sale (Shaped)
800 MW Assured Delivery

Impact to BPA (1989-2006)
including Mitigation
$Millions 1987 (NPV)

	Alternative 2			
	(a) MPC Power Sale	(b) Seasonal Exchange 50%	(c) Firm Surplus Sale	(a+b+c) Total
1. Secondary Sales	(76)	(60)	(161)	(297)
2. Wheeling Revenues	25	60	69	154
3. PF Sales	---	(57)	---	(57)
4. Net Impact (1+2+3)	(51)	(57)	(92)	(200)
5. Mitigation	13	32	37	82
6. Net Impact w/Mit	(38)	(25)	(55)	(118)
7. Annual Cost w/Mit	(3)	(2)	(4)	(9)

B. Summary of Comments

There is no simple breakdown of comments on this issue according to region or nature of commenter. Our most recent proposal is supported by commenters in the Northwest and California, and by generating and nongenerating utilities. However, there are also strong views that 800 MW is either too much Assured Delivery capacity or not enough.

Our nongenerating utility and DSI customers generally oppose IAP provisions that would reduce the transmission capacity available for BPA sales either in the long-term or spot markets. Assured Delivery capacity made available to generating utilities comes at the expense of revenue-producing transactions BPA could otherwise conduct over the Intertie. This can create upward pressure on BPA's rates. The DSIs summed up this concern by stating "[t]he mere fact that, at times, there is excess Intertie capacity does not impose on BPA an obligation to provide access at other times. BPA has the discretion, but no obligation, to provide such access. If it exercises that discretion, BPA must meet its statutory and other obligations, including its obligation [to] keep power rates as low as possible." DSI, #3-214, pp. 1-2.

EWEB commented that "BPA is correct to limit transaction amounts ... on Intertie access for firm power sales and exchanges by nonfederal utilities." EWEB, #3-200, p. 1. EWEB states that this limit has a "direct economic impact on BPA's ability to market its surplus power, which must be maintained in order for BPA to continue to provide competitive Priority Firm rates and to meet its U.S. Treasury repayment obligations." EWEB, #3-200, p. 1.

While urging caution, our total requirements customers do not oppose strenuously the increase of Assured Delivery capacity from 420 MW to 800 MW. An essential condition to this support is the "mitigation measures" discussed later in this decision. NGPU states, "We accept as appropriate that amount, given full mitigation of losses to BPA." NGPU, #3-100, p. 4. APAC supports "BPA's expansion of the amount of Intertie capacity that is allocated to assured access for firm transactions if those transactions are mitigated in such a way as to minimize financial harm to BPA." APAC, #3-110, p. 1.

However, DSIs and nongenerating utilities alike resist any increase beyond 800 MW. For example, WPAG stated:

> The record contains no analysis to assess the potential revenue impacts to BPA of increasing the amount of Intertie capacity made available to non-federal utilities beyond 800 megawatts. Further, BPA has declined to study what financial impacts 800 megawatts of Assured Delivery will have on BPA should the Third A.C. be delayed or not built at all. Without such analysis, and in the absence of any demonstrable need, it would be extremely imprudent for BPA to increase the amount of Intertie being made available for Assured Delivery. WPAG, #3-201, p. 6.

The proposal in the 1987 draft policy is also supported by publicly owned generating utilities in the Northwest and California. "The PGP has endorsed BPA's decision to limit the Assured Deliveries to 800 MW's because it demonstrates a commitment to the regional partnership mandated by Congress and essentially leaves BPA revenue neutral." PGP, #3-194, p. 1. SCL's reaction to the 800 MW number is that "it probably is adequate for today but ... what the Policy needs is a commitment from Bonneville to when and if the 3rd AC is completed, to reopen that issue and look at whether that number might want to go up." SCL, Tr. 490.

Like Seattle, the California publicly owned utility membership of TANC expressed support for BPA's proposed limit. However, TANC also requests a commitment from us in the LTIAP to increase the amount of Assured Delivery when the COTP is operational and the transfer capability to the Southwest is increased. TANC, #3-182, p. 2.

Rather than focus on commercial operation of the third AC line, some commenters asked that the 800 MW limit be revisited after a trial run. For example, WUTC requested, "[W]e would like to see a provision in the final policy that commits Bonneville to <u>increasing</u> the allocation for seasonal exchanges if the impacts on the agency's revenue are found to be minimal, or if the impacts can be successfully mitigated." WUTC, #3-179, p. 2.

As a variant on the WUTC theme, PSP&L prefers that any future increase in the amount of Assured Delivery be tied to demand:

> The 800 megawatts of Intertie capacity for Assured Delivery referenced in the draft should not be an absolute limit. Rather, the LTIAP should specify that the amount of capacity made available for Assured Delivery will be reexamined with respect to increasing such amount at any time that requested capacity for Assured Delivery exceeds 800 megawatts. PSP&L, #3-117, p. 5.

ICP generally is supportive. It requests as an accommodation to generating utilities that we increase Assured Delivery capacity by an immediate 25 to 50 percent. "[I]nformal surveys indicate that it is not far from being sufficient; we suggest that a relatively small increase, say to 1000Mw or 1200Mw, might avoid the rush to complete contracts that might be caused by even a slightly inadequate quantity ... ." ICP, #3-119, p. 10.

Two California investor-owned utilities approach the Assured Delivery limit from a different perspective. PG&E asks us to determine our own needs for firm Intertie capacity without regard to capacity needs for spot-market transactions and make the remaining physical capacity of the Intertie available for Assured Delivery. "BPA has the statutory right to reserve a portion of its Intertie share to meet its reasonably foreseeable needs, but even if BPA is able to market all of its surplus firm resources it will still have approximately 2,000 MW available to provide Assured Delivery to utilities." PG&E, #3-188, p. 28. PG&E commented further that, "[t]he LTIAP would place an artificially low ceiling of 800 MW on all long-term firm transactions other than BPA's." Id., p. 27.

Other California utilities found 800 MW too limiting. SCE commented, "BPA's proposal to provide only 800 MW of firm access is both arbitrary and inadequate. The 800 MW limit has no technical or operational basis." (Emphasis in original.) SCE, #3-187, p. 10. SCE would base the Assured Delivery limit on historical sales by BPA, using 1983 and 1976 as representative years in which BPA had two-thirds of sales over the Intertie. SCE concluded, "Even assuming that BPA intends to reserve two-thirds of the total Intertie for itself (total Intertie being 6200 MW), 2000 MW would be available for non-federal use and even with Portland General Electric and Pacific Power & Light controlling 1000 MW, there should still be 1000 MW left for the other nonfederal Northwest utilities, not just 800 MW." Id., p. 11-12.

At the other extreme, Big Bend and Umatilla cooperatives opposed the availability of any Assured Delivery capacity until the third AC transmission line goes into commercial operation. In advocating a "Federal first" Intertie policy that protects full-requirements customers, both utilities commented, "limited use by third parties may be appropriate if and when the third AC line is completed, but not before." Big Bend, #3-90, p. 1; Umatilla, #3-104, p. 1.

C. Analysis and Decision

There is no single method of computing the amount of Assured Delivery capacity that we can make available without seriously degrading our revenues. BPA staff and the PNUCC staff that reviewed our studies each concluded that it would be unwise to place too much faith in studies that are so dependent on assumptions regarding rainfall; load growth in California and the Northwest; and oil, natural gas, and aluminum price fluctuations. Tr. 8. BPA lost over $213 million in FY 1987; we do not want to exacerbate this problem with the final LTIAP. Tr. 54, 471-2. Given these uncertainties, we are understandably cautious about committing major portions of the Intertie for long-term nonfederal use and about the economic consequences of the set of new concepts incorporated into the 1987 draft policy.

Yet, the 800 MW upper limit in itself is a fairly dramatic departure from the past. It will facilitate a greater number and variety of firm transactions than before. Our studies indicate an annual revenue loss of approximately $9 million in lost nonfirm revenue and displaced firm power sales to our public agency customers. Tr. 7. The revenue effects on BPA have been quantified further in a study by PNUCC. Tr. 871-78; Study, Tr. 865-70. These adverse revenue effects, offset by mitigation measures discussed below, have been found acceptable by a fairly broad cross-section of commenters.

Given the judgmental element of this decision, it seems appropriate to look for possible consensus among the commenters. We must balance three basic objectives: Northwest generators' desire to sell or exchange power on a firm basis to California; our total requirements customers' concerns about rate stability; and our obligation to repay the Treasury. 24/

As we look for consensus, the PG&E proposal for committing 2,000 MW to Assured Delivery must be rejected as excessive. It ignores BPA's significant need to sell surplus nonfirm energy at certain times of the year to the California market. This need will exist regardless of how much surplus firm power we are able to sell, and Intertie capacity must be reserved to deliver it. Our nonfirm energy constitutes a "foreseeable" surplus for which Intertie capacity may be reserved. Department of Water & Power, 759 F.2d at 692.

We also have the authority to reserve excess Intertie capacity for non-Federal sales of nonfirm surplus, rather than allocating all of the excess capacity to firm sales. Some Northwest utilities that have hydro resources

24/ Regarding the Treasury, it is important to bear in mind that the revenues we earn from Federal Intertie usage are critical to repaying the Federal government's $8 billion investment in the Northwest's Federal power and transmission systems. This investment was made with the expectation that it would be repaid, with interest, with revenues from our sales. We have the responsibility for establishing policies which ensure that sufficient revenue will be generated to cover all our costs, including planned repayments to the Treasury.

have only nonfirm surplus and only during certain times of the year. These utilities, as well as many of the utilities which have firm surplus or which desire to enter into seasonal exchanges, have need of Intertie capacity to make the best use of this nonfirm but valuable resource. In addition, given our decision on extraregional access, if PG&E's proposal were adopted, Canadian utilities might not receive any access to the Intertie. BPA believes it is in the best interests of the region, Canada, and California to reserve Intertie capacity for nonfirm sales rather than commit all of the excess capacity to non-Federal firm transactions.

Similarly, we reject the Big Bend and Umatilla objection to any amount of Assured Delivery. We believe these transactions can bring benefits to the Northwest and to California. Some may even bring benefit to BPA in the long run. We will provide non-Federal access to the Intertie if the adverse impacts on BPA are within an acceptable range.

Among the remaining comments, 800 MW -- together with a commitment to reexamine when the third AC line is completed -- reasonably satisfies nearly all expectations. Our total requirements ratepayers seem satisfied so long as the 800 MW limit is not exceeded without further study. Northwest generating utilities and WUTC are satisfied provided we undertake further study to review BPA's ability to provide, and Northwest utilities' demands for, incremental Assured Delivery capacity.

The fear of ICP, SCE, and PG&E about the possible inadequacy of 800 MW is not borne out by our recent negotiations with Northwest utilities expressing a concrete interest in firm power transactions with the Southwest. If each of these five transactions were consummated, they would utilize slightly more than half the 800 MW capacity limit over the next five years. But five years from now, the third AC line should be in commercial operation and BPA will have concluded its reassessment of the Assured Delivery limit. In short, our negotiations cause us to reject PG&E's proposition that the selection of 800 MW "would place an artificially low ceiling ... on all long-term firm transactions other than BPA's."

Moreover, the LTIAP provides additional opportunity for utilities to enter into joint ventures that would allow BPA to market surplus power as part of three-party arrangements involving California utilities. Because of the power sales benefits flowing to BPA, Intertie capacity reserved for BPA's use will in effect be made available for such transactions. "If firm sales have not been consummated then the Joint Venture and firm displacement-type transactions which utilize federal access should be pursued." PGP, #3-194, p. 2. These provisions are discussed later in this decision.

We conclude that 800 MW is a reasonable limit on Assured Delivery capacity. Within this limit, firm transactions subject to the mitigation provisions of section 4(d) should not produce serious adverse revenue consequences for BPA. This conclusion is strengthened if scheduling utilities use Assured Delivery capacity for low load-factor exchanges more than for high load-factor sales. If mitigation provisions were not a part of the LTIAP, concerns about BPA revenues would have caused us to select a lower limit.

Section 4(c)(1) of the final LTIAP carries forward BPA's commitment to reexamine the limit on Assured Delivery capacity when the third AC transmission line goes into commercial operation. To ensure that this question is revisited regardless of the outcome of the third AC project, section 4(c)(1) will also provide that BPA will revisit the 800 MW limit if the third AC Intertie project is not completed. Our future decision on increased capacity will, of course, be tempered by scheduling utilities' willingness to abide by the revenue-protective measures of the final policy.

Studies discussed in the IDU EIS address the effects of making up to 800 MW of capacity available for non-Federal firm transactions. These studies show a potential impact on resident fish and cultural resources under both the Federal Marketing case and the Assured Delivery case due to the potential changes in elevations at the Hungry Horse (Montana) hydro reservoir. IDU EIS, section 4.2.2-8. We are working with the Montana Department of Fish, Wildlife and Parks to evaluate and, if necessary, mitigate impacts to resident fish. We are also participating in funding surveys of cultural resources at the Columbia and Snake River Federal storage reservoirs to determine the need and methods for mitigating adverse effects on cultural resources. 25/

ISSUE NO. 2: **How should the 800 MW set aside for Assured Delivery be allocated by utility and by type of firm transaction?**

REFERENCE: **1987 draft policy §4(d)(2)(B)**
Final LTIAP §4(c)(2)

A. BPA Proposal

In the 1986 draft LTIAP, each scheduling utility was allocated a portion of the 420 MW available for transmission of Northwest non-Federal firm power sales. Individual allocations, shown in "Exhibit B" to the draft policy, were based on each utility's share of the regional firm surplus.

Exhibit B does not provide surplus numbers for PGE or PP&L. These two utilities have their own Intertie capacity, which is larger than their average firm energy surplus. Consequently, because of our determination to reduce a utility's average firm energy surplus by its own Intertie capacity, neither utility is listed in Exhibit B.

By the time the 1987 draft policy was released, PNUCC's regional surplus estimate had declined to 320 MW. This new figure was augmented by extra

25/ We would address these matters again before making any decision to increase Assured Delivery capacity beyond 800 MW.

capacity made available to MPC, for a new Exhibit B total of 361 MW. Individual scheduling utilities once again were to receive shares of the total.

As we attempted to accommodate demands for seasonal exchange transmission capacity, we came to the conclusion that exchanges cause less severe spot-market impacts on BPA than power sales for two reasons. First, these exchanges tend to be low load-factor transactions that utilize the Intertie for only eight to ten months per year (four to five months in each direction). Over the course of a year, BPA would dedicate less Intertie capacity to these transactions than to year-round, high load-factor sales, leaving more capacity available for Federal sales. Second, seasonal exchanges create a wintertime return energy market in the Northwest for which BPA and other Northwest sellers can compete if their prices are lower than the incremental costs of exchanging utilities in California. Tr. 62.

However, exchanges are not totally beneficial. They have two major disadvantages for the long-term marketing efforts of BPA and the Northwest in an era of surplus. First, exchanges eliminate access to the more lucrative heavy summer load-hour markets in the Southwest without decreasing the overall Northwest surplus. In fact, seasonal exchanges increase the Northwest's wintertime surplus by returning energy during the less-lucrative winter market, thereby increasing BPA's surplus and the probability of spill on the Federal hydro system. Second, exchanges bring energy back to the Northwest during light load hours, thereby increasing operational problems. MPC, #3-111, pp. 3-4.

We believe that the disadvantages of exchanges tend to cancel out their benefits. However, to recognize the demand for seasonal exchanges, the 1987 draft policy made available an additional 440 MW of capacity. We proposed to allocate this 440 MW among Northwest utilities based on utility summer surpluses. No specific allocations were provided in the 1987 draft.

B. Summary of Comments

In addition to concerns about utility needs and BPA revenues, the comments indicate that there is a significant environmental issue at stake in this determination. Comments support the Exhibit B regional surplus limitation on sales of firm power. PGP stated, "We like the idea of the Exhibit B usage in a sense for limiting firm exchanges to the 360 megawatts for firm sales. We don't want people constructing resources to make firm sales." PGP, Tr. 383. In a similar vein NRDC commented, "The Policy includes a crucial common-sense safeguard that was missing from the earlier version: no utility can make long-term commitments to sell more surplus power than it now controls (section 4(d))." NRDC, #3-132, attachment p. 3.

PGE and PP&L both questioned BPA's calculations of firm surplus amounts in determining how much they should be allocated in Exhibit B. PGE suggests that it be allowed the total of its average firm surplus in the PNUCC Regional Forecast of 258 MW. PGE, #3-133, p. 4. PP&L calculated its own Exhibit B amount of 99 MW. PP&L, #3-138, p. 3.

Capacity available for exchanges. Inclusion of seasonal exchanges in the 1987 draft was well received. "Western commends BPA for its recognition of seasonal exchanges. Such exchanges will benefit both regions as they make for the efficient use of resources." WAPA, #3-189, p. 3. "[W]e feel quite strongly that seasonal exchanges which result in a decreased need for the construction of new power plants at either end of the line should be facilitated to the maximum extent possible." Friends of the Earth, #3-203, p. 3. "[T]he promotion of transfers [exchanges] ... is ... a way of reducing environmental impacts through the construction of additional facilities." PSP&L, Tr. 481.

Criticism of the 1987 draft's proposal focused on the share of the 800 MW capacity limit devoted to exchanges. WAPA, #3-189, p. 3; LADWP, #3-192, p. 3; PG&E, Tr. 427; PSP&L, Tr. 55. A second criticism addressed limitations placed on the types of exchanges permitted. PG&E, #3-188, p. 84; SCE, #3-187, p. 14; SDG&E, Tr. 442.

ICP raised a definitional problem: how to distinguish between sales and exchanges when a firm sale may convert to a seasonal exchange. "[W]e continue to propose that the block of Intertie made available for nonfederal Assured Delivery be treated as a monolith. Most of the contracts completed or currently in negotiation cannot be clearly defined as firm power sales, firm capacity sales or exchanges." ICP, #3-119, p. 10.

PPC recommended eliminating most distinctions between types of transactions. "[O]nce an amount of Assured Delivery is determined for the final policy, there should be no strict limitations within that amount regarding the split between power sales and exchanges, except to the extent that Exhibit B limits firm power sales." PPC, #3-125, p. 4. Similarly, WAPA and WWP requested that BPA remove the 440 MW limit for seasonal exchanges. WAPA, #3-189, p. 3. WWP believes that seasonal exchange constraints based upon summertime firm surpluses are matters best left for resolution under the Pacific Northwest Coordination Agreement. WWP, #3-122, p. 21.

Types of exchanges. The term "exchange" can refer to various transactions that take advantage of diversity between Northwest and Southwest loads through deliveries of firm power from north to south during the Southwest's peak demand times and returns of capacity and energy from south to north during other times. Transactions vary depending on the lag between deliveries and returns. A "naked capacity" transaction might require offpeak energy returns within 24 hours, whereas a capacity-energy exchange might require energy returns later during the same season.

There are no specific provisions in the 1987 draft policy that permit these types of exchange transactions. BPA staff simply did not perceive a demand for such transactions at the time the 1987 draft was released. BPA, Tr. 84. Comments from a cross-section of generating utilities recommended that BPA rectify this omission.

PG&E misread our intent, stating "[T]he LTIAP flatly prohibits valuable transactions by denying long-term firm transmission service for capacity-energy exchanges over BPA's share of the Intertie." PG&E, #3-188, p. 3.

SCE recommended, "Exchanges should not be restricted to just the seasonal variety. Northwest and California utilities will benefit from capacity-for-energy exchanges ... . BPA should not prohibit capacity sales ... nor should BPA rule out other transactions such as generating unit purchases and sales." SCE, #3-187, p. 14. These observations were echoed by California publicly owned utilities: "TANC recommends that BPA include provisions in the policy for capacity-energy exchanges, peaking capacity sales, straight energy sales, and other reasonably foreseeable types of transactions in addition to seasonal exchanges and firm power sales." TANC, #3-182, p. 2.

SDG&E noted that "[a]lthough these types of contracts may not be viable now, to preclude them completely from a long term policy is short sighted." SDG&E, #3-196, p. 2.

In the Northwest, the publicly owned generating-utility members of PGP suggested that "provision for seasonal exchanges in section 4(d)(3) be expanded to include opportunities for a wider variety of transactions if those transactions meet all of the Assured Delivery and Mitigation provisions and would cause no adverse impacts on the operation of the northwest coordinated system. PGP, #3-124, p. 4.

C. Analysis and Decision

All California utilities find exchanges advantageous. In the Northwest, however, the balance between benefits and costs of exchange transactions depends on whether a regional or individual utility perspective is employed. From the regional perspective, which BPA is often encouraged to take, the Northwest has a year-round firm surplus. The time of possible vulnerability for serving Northwest regional loads is not the winter peak. Instead, it is the month of August when recreational constraints on reservoir drawdown can limit generation by the regional hydropower system. Tr. 6. From a regional perspective, the Northwest may not be advantaged by exchanges that draw on this system during the summer for deliveries to California and increase the wintertime surplus with return energy from California. MPC, #3-111, pp. 3-4.

Individual Northwest utilities view exchanges differently. WWP and PSP&L face near-term winter needs. To utilities such as these, seasonal exchanges may be the lowest-cost incremental source of wintertime power. The flexibility of the coordinated Northwest power system may be used to shift any August delivery vulnerability to the region as a whole.

By and large, comments about exchanges came from utilities in the Northwest and California that would benefit from such transactions. The "Northwest regional" perspective was underrepresented. MPC was virtually alone in pointing out the possible shortcomings of these transactions.

From BPA's perspective, our key concern about exchanges is their possible adverse effects on summertime operational constraints. We have not been able to devise a generic solution to this problem. However, we are fairly confident that exchanges likely to be consummated under the 800 MW Assured Delivery limit should not cause operational problems during summer months. Proposed contracts will be reviewed on a case-by-case basis under section 3(c)(4) of the LTIAP to test this expectation.

The potential environmental effects of seasonal exchanges were addressed in the IDU EIS analyses. These studies indicated that, in combination with other types of power transactions, seasonal exchanges in excess of 500 MW have the potential to produce significant adverse effects on cultural resources surrounding Columbia and Snake River Federal storage reservoirs (See IDU EIS sections 4.2.2.3, 4.2.2.5). They may also have significant adverse effects on resident fish at Hungry Horse reservoir (See IDU EIS section 4.2.3.3). If exchanges are increased beyond 700 MW, resident fish at Libby reservoir would also be adversely impacted. However, both the cultural resource and resident fish effects are being addressed through implementation of appropriate mitigation measures.

The final LTIAP includes a definition of "exchange" that covers a variety of transactions, including capacity-energy exchanges and naked capacity sales. This term has been substituted for "Seasonal Exchange" throughout the LTIAP. This change satisfies the concerns of California generating utilities and PGP, with no erosion of BPA revenues in comparison to provisions in the 1987 draft.

As for the limits on types of transactions, BPA is convinced of the wisdom of imposing Exhibit B limitations on firm power sales. From the standpoints of environmental quality and financial risks, it seems appropriate to limit Assured Delivery capacity to the amount of firm surplus presently available in the Northwest for export sales. NRDC, #3-132, p. 3; IDU EIS, S-8. BPA was uncertain in the last draft of the LTIAP where to include provisions for existing agreements for firm sales. Tacoma and Longview Fibre/Cowlitz have agreements with WAPA that total 86 MW. BPA has increased the Exhibit B firm surplus allocations to include these sales. (See discussion at Section 2, Issue 3.) This increases the Exhibit B firm surplus total to 444 MW. However, our discussions with utilities in the Northwest lead us to conclude that 444 MW is a high estimate of the amount of non-Federal firm sales likely to be consummated with Southwest utilities. Consequently, the environmental and economic impacts will likely be less.

In calculating the Exhibit B firm surplus allocations, we relied on data submitted by the utilities for the 1987 PNUCC regional forecast reflecting their 1988-89 requirements and resources. Using this data assures consistency and reliability in determining each utility's average firm surplus. In this submittal PGE had a firm surplus of 258 MW and 75 MW of export sales for a total of 333 MW. Since PGE currently has 700 MW of capacity in the Intertie, its entire firm surplus can be transmitted over its own capacity. PP&L's submittal to the PNUCC differs from the calculations in its comments to BPA on the draft policy. In the 1987 Regional Forecast PP&L had a firm surplus of 330 MW of which 67 percent or 221 MW is considered to be its regional amount. This amount combined with its export of 28 MW in the PNUCC Regional Forecast equals 249 MW. PP&L has rights to deliver 300 MW for sales to California at the Malin Substation; this right covers the 249 MW total.

We have concluded that Exhibit B amounts need not be used exclusively for firm sales. There is no apparent reason to preclude scheduling utilities from using their individual Exhibit B amounts for firm exchanges which, in the words of PGP, "meet all of the Assured Delivery and Mitigation provisions and would cause no adverse impacts on the operation of the northwest coordinated system." PGP, #3-124, p. 4. This modification should overcome the definitional problem discussed by ICP.

The final LTIAP does not allocate the remaining 356 MW of Assured Delivery capacity among scheduling utilities. That amount will be available for exchange transactions of scheduling utilities on a first-come, first-served basis. BPA has not allocated the remaining capacity based on individual utility summer surpluses due to the lack of information on which to calculate such allocations. Proposed contracts will be reviewed on a case-by-case basis under section 3(c)(4) of the LTIAP to determine their possible adverse effects on summertime operational constraints.

Section 4(c)(2) of the LTIAP provides that scheduling utilities may utilize their individual Exhibit B transmission capacity whenever they elect to enter into long-term firm transactions with Southwest utilities. This provision reserves the capacity for each utility with an Exhibit B amount and eliminates the concern of utilities about a possible "gold rush" effect if Assured Delivery contracts had to be negotiated by a specific deadline. However, after a reasonable period of experience we may utilize section 4(c)(3) of the final LTIAP to withdraw unused Exhibit B capacity from individual utilities. Any withdrawn capacity will be added to the 356 MW portion of Assured Delivery capacity to be made available to scheduling utilities on a first-come, first-served basis.

ISSUE NO. 3: **Should the LTIAP resolve a controversy over alleged rights to firm Intertie wheeling of Montana Power Company's share of the Colstrip No. 4 coal-fired generating plant?**

REFERENCE: **1987 draft policy Exhibit B**
Final LTIAP Exhibit B

A. BPA Proposal

In 1985, MPC offered the entire output of its Colstrip No. 4 share for acquisition by BPA. After BPA declined this offer for lack of need within the Northwest, MPC claimed priority under Northwest Power Act section 9(i)(3) to firm Intertie wheeling service for 210 MW of Colstrip. When that request was denied, MPC petitioned for review by the U.S. Court of Appeals for the Ninth Circuit. Montana Power Co. v. BPA, 9th Cir. No. 86-7330.

After preliminary negotiations with MPC in November, BPA included in the 1987 draft policy a proposal for resolving a controversy about firm wheeling of power from MPC's portion of the Colstrip No. 4 generating station. The proposal increased the amount of MPC's Exhibit B Assured Delivery capacity from 80 MW to 105 MW (one-half MPC's share of Colstrip No. 4 capacity).

B. Summary of Comments

The Governor of Montana supported BPA's increased allocation to 105 MW in settlement of obligations under section 9(i)(3) of the Northwest Power Act. If settlement could not be reached prior to finalizing the policy, he requested that "the IAP remain flexible enough to incorporate the terms of a later agreement, while allowing MPC to meet its existing sales obligations." Governor of Montana, #3-127, p. 1.

Vigilante opposed MPC's allocation of 105 MW of Intertie capacity and stated, "Our public utilities who are not now generating, but working on hydro and other resource development may well need this capacity in the near future. In the meantime, BPA should use this capacity in the most cost effective manner to maximize revenue." Vigilante, #3-140, p. 1.

PPC, an intervenor in the Ninth Circuit proceeding, insisted that "BPA should receive written assurances from MPC that this particular amount will indeed lead to settlement of the dispute." PPC, #3-125, p. 4.

EWEB commented, "Montana Power has shown no basis to be excused from costs of mitigation. The existence of a [section] 9(i)(3) resource in conjunction with BPA's legal requirements to wheel does not provide a basis for those costs to be paid by the Region." EWEB, #3-200, p. 3.

C. Analysis and Decision

It strains credibility to suggest, as Vigilante does, that BPA should deny Intertie access for existing needs so that Intertie capacity will remain available for resources yet to be developed. BPA does not intend to use the LTIAP to encourage resource construction for export. A utility's allocation for firm sales outside the region is based on its existing firm surplus which can be supported in the future with new resources but cannot be increased by acquisition of new resources. Furthermore, Vigilante should be especially aware of the fish and wildlife protected area restrictions on new hydro development before it considers new resources.

A common sense argument can be made for wheeling the settlement amount of Colstrip capacity because MPC's share of Colstrip is surplus to long-term Northwest needs. In addition to BPA's rejection of MPC's offer of Colstrip capacity, the Montana Public Service Commission has been unwilling to include the cost of that resource in retail rates, instead urging the utility to acquire other resources as Montana loads increase. Long-term firm export sales, such as the MPC sale, were analyzed in BPA's IDU EIS and no significant environmental problems were uncovered.

We have reached a settlement that will provide MPC with 105 MW of Assured Delivery capacity to facilitate a firm sale of the output of Colstrip No. 4. BPA and MPC have negotiated, contingent on implementation of the LTIAP, a series of main-grid and Intertie wheeling agreements that require MPC to satisfy annual mitigation requirements for the life of the Colstrip sale. Also, MPC has agreed to a formula rate that will reduce the charges imposed on BPA by MPC for transfer service to our Montana loads. Finally, MPC will move to dismiss, with prejudice, Montana Power Co. v. BPA, 9th Cir. No. 86-7330.

This settlement should meet the reasonable expectations of all who commented on the issue. Based on MPC's regional firm surplus, the IAP would have granted MPC 80 MW of Assured Delivery. MPC argued that it should receive 210 MW of Assured Delivery as a statutory right under section 9(i)(3). The additional 25 MW provided by BPA is an acceptable compromise settlement of litigation over a difficult issue with an uncertain outcome. If for any reason settlement is not reached, MPC's extra capacity will revert to other Northwest utilities for Assured Delivery service.

ISSUE NO. 4: **Should conservation be included among the resources eligible for Intertie access under the LTIAP?**

REFERENCE: **1987 draft policy - no reference**
Final LTIAP §1 #17

A. **BPA Proposal**

In the 1986 and 1987 drafts of the LTIAP, the definitions of "Qualified Northwest Resource" and "Resource" were limited to generating resources. Conservation is not mentioned.

B. Summary of Comments

Comments from a variety of sources pointed out the inequality of treatment of conservation compared to generating resources and in use of conservation as part of a marketing strategy. Mason, #3-87, p. 1.

NCAC complained that the draft LTIAP "does not so much as acknowledge the possibility of a generating or non-generating utility independently developing conservation resources and making a sales transaction based on the saving from those resources. We and others have been urging, for 5 years now, that such conservation-based sales were a necessary and proper element of a wise inter-regional sales strategy." (Emphasis in original.) NCAC, #3-206, pp. 3-4.

A study submitted with PG&E's comments concluded that the draft LTIAP would prohibit or discourage the realization and use of conservation for firm transactions. PG&E, #3-188, attachment p. 8.

Statutory concerns were pointed out by WPAG in a conflict between section 4(e) of the Northwest Power Act and the lack of provision for conservation in the draft LTIAP, while "permitting new generating resource development, including baseload thermal, to support export sales." WPAG, #3-123, p. 22.

NRDC stated that it does not want the policy to encourage building power plants instead of less expensive conservation. NRDC, #3-132, pp. 5-6.

On the other hand, PGP opposes consideration of Assured Delivery for any new resources "based upon potentials, future resources, conservation transfers or planned load reductions" until after the third AC Intertie is operational. PGP, #3-194, p. 3.

C. Analysis and Decision

We disagree with the comments which conclude that we are prohibiting or discouraging conservation by not including conservation in the definition of

"Resource." A Scheduling Utility may support its continuing ability to meet its obligations under a firm export contract by implementing conservation on its system to defer or avoid the necessity to acquire new generation as its own load increases. It becomes a question of the economics of conservation measures versus the economics of purchasing new generation. In no way does the LTIAP discourage or prohibit such an election.

A scheduling utility can also meet its obligations to serve its own load under the waiver requirement (section 4(a)(4)) by implementing conservation on its system rather than acquiring new generation. In no way does BPA insist that such load be met with new generating resources.

With respect to WPAG's comment about section 4(e) of the Northwest Power Act, that section applies to resources acquired by BPA. It does not apply to matters involving nonfederal resources or to BPA's transmission responsibilities.

We do not agree that nongenerating utilities can have a surplus to be exported. Defining conservation as the resource to be delivered over the Intertie would arguably allow utilities to sell to California power purchased under their BPA section 5(b) power sales contracts if an equal amount of conservation were implemented on their systems. We have consistently asserted that this result would violate section 5(b) of the Northwest Power Act and the provisions of the power sales contracts.

We also disagree with the notion that scheduling utilities could increase their Exhibit B amounts by implementing conservation or that utilities without Exhibit B amounts could create them by implementing conservation, as Friends of the Earth, WPAG, and Mason seem to argue. BPA has determined that it will provide a maximum amount of Assured Delivery for firm sales. That amount is based on the average firm surplus calculated from individual utility submittals in the PNUCC's 1987 Northwest regional forecast. The LTIAP does not provide for increasing that amount as a result of any future action, including conservation, that might increase the utility's firm surplus.

ISSUE NO. 5: **How will access for nonscheduling utilities and computed requirements customers be provided under the LTIAP?**

REFERENCE: **1987 draft policy §1, definition 11**
LTIAP §1, definitions 12 and & 18

A. BPA Proposal

The 1987 draft policy limited the definition of "scheduling utility" to the Northwest portion of a nonfederal utility that operates a generation control area in the Northwest. Exhibit B tends to blur this definition. Cowlitz and EWEB, which are computed requirements customers, have Exhibit B amounts even though they do not qualify for an Exhibit B amount under the definition. "Nonscheduling utilities" must request Intertie access through the scheduling utility (or BPA) in whose control area a resource is located.

B. Summary of Comments

Cowlitz would expand the definition of "Scheduling Utility" to include "any utility within BPA's generation control area that has non-federal generating resources and which is designated as a Computed Requirements customer." Cowlitz, #3-129, p. 1. EWEB and PGP recommended the same change. EWEB, #3-137, p. 2; PGP, #3-124, p. 3.

PNGC's members are total requirements customers of BPA. They own 50 MW of the Boardman coal-fired generating station. PNGC recommends that section 4(c) clarify that nonscheduling utility access will be provided via Intertie capacity reserved for BPA. PNGC, #3-141, p. 3.

C. Analysis and Decision

We agree with Cowlitz that the definition of "Scheduling Utility" should be revised to include BPA's computed requirements customers. This is consistent with previous policies and clarifies treatment of computed requirements customers under the LTIAP.

Nonscheduling utilities will continue to be required to make Intertie arrangements through the utility who has control over their generation or directly with BPA. If the nonscheduling utility acquires access, such access would utilize Intertie capacity reserved for BPA.

ISSUE NO. 6: **Should BPA maintain provisions for joint ventures and, if so, should BPA make the provisions more detailed?**

REFERENCE: **1987 draft policy §4(c)**
Final LTIAP §4(b)

A. BPA Proposal

In the 1987 draft policy, BPA identified two types of transactions outside Exhibit B limitations: joint ventures with BPA and sales in lieu of exchanges. These are means of obtaining Assured Delivery in excess of the capacity limitation contained in the LTIAP. Such transactions would provide BPA with opportunities to sell its surplus power. Under joint ventures, BPA and scheduling utilities would each sell surplus power to California utilities. In a sale in lieu of exchange, BPA would sell firm power to a Northwest utility in need of winter capacity and provide that utility with Assured Delivery to deliver power to the Southwest during summer months.

B. Summary of Comments

WAPA found the proposal for joint ventures attractive. "We support the Joint Venture proposal since it would allow recoupment of funds spent by Western on transmission facilities through economically advantageous resource purchases to support Western's Central Valley Project loads from Midwest purchases ... ." WAPA, #3-189, p. 3.

PG&E was concerned about the clarity of potential mitigation measures for joint ventures. It stated, "[w]e have no problems with joint venture in general, but we are very suspicious that what BPA has in mind is mitigation measures and other payments ... which will make those exchanges extremely expensive ... ." PG&E, Tr. 428.

C. Analysis and Decision

We maintain provisions in the LTIAP for joint ventures and sales in lieu of exchanges. Our objective is to make additional sales of surplus energy or engage in other transactions that can increase BPA's revenues. Additional sales of Federal surplus should make additional Intertie capacity available to others. However, we do not intend for this LTIAP provision to predetermine the outcomes of individual negotiations. The terms of these arrangements will be determined case by case. Obviously, in such situations all parties to a joint venture must propose terms that are mutually agreeable. If PG&E is not satisfied with BPA's terms in any joint venture proposed for its participation, the transaction obviously would not occur.

These transactions are outside the limits of Exhibit B, providing an additional opportunity for utilities to gain access for firm arrangements. They also provide a means for utilities who have rights to their own Southwest interconnections to obtain capacity for firm transactions over BPA's capacity.

Section 2. CONDITIONS ON ASSURED DELIVERY ACCESS

ISSUE NO. 1: **Should the LTIAP require scheduling utilities to waive BPA's obligation to serve their loads in return for Assured Delivery capacity to facilitate long-term export sales?**

REFERENCE: **1987 draft policy §4(b)**
Final LTIAP §4(a)(4)

A. BPA's Proposal

Section 4(b) of the 1987 draft policy requires a waiver of our contractual obligation to serve a utility's load growth up to the amount of any firm power sale receiving Assured Delivery. The provision would prevent a scheduling utility from utilizing its BPA power sales contract to shift the burden of new resource development to BPA and our customers in the event that utility "oversold" its firm surplus for export to California. The provision applies only to sales, not to exchanges.

B. Summary of Comments

NRDC provides support for our proposal. "The ability to draw on the region's credit when deals go bad is an invitation to negotiate imprudent power sales. The problem is an unintended outgrowth of the power sales contracts that BPA executed with all Northwest utilities back in 1981; the solution appears in section 4(b) of the proposed Policy ... ." NRDC, #3-132, p. 3, attachment. <u>See</u> NWPPC, #3-139, p. 2.

While NRDC advanced an environmental argument, NWPPC presented the views of BPA customers whose rates might bear the cost of any resources BPA might acquire in the absence of LTIAP section 4(b). "We support ... section 4(b) of the revised policy, which we understand to incorporate the requirements of sections 9(c) and 9(d) of the Northwest Power Act. This provision should avoid a situation where Bonneville must acquire new resources to serve loads that had been served by resources that were sold outside the region." NWPPC, #3-139, p. 2. See also Mason, #3-87, p. 1.

The generating utility members of PGP requested that BPA add a qualification to the end of section 4(b), making the waiver dependent on future events. "A scheduling utility will receive Assured Delivery for firm sales if it agrees to waive BPA's obligation to serve that scheduling utility's firm load under its Power Sales Contract up to the amount of power given firm Intertie access if BPA is substantially impacted when BPA reaches load/resource balance." PGP, #3-124, p. 5. The non-generating utility membership of WPAG, on the other hand, requests a strong provision without qualification. WPAG, #3-123, p. 11.

MPC requested special dispensation. "Montana Power has already met its responsibility by offering the resource to the region, that is why Colstrip Unit 4 is a section 9(i)(3) resource. By offering that 210-megawatt resource to the region, Montana Power has already firmed up its future resource requirements that it might place on BPA and, therefore, the provision that a utility must waive its right to place load requirements on BPA if it sells power out of the region should not apply to any power which is being sold pursuant to section 9(i)(3)." MPC, #3-212, p. 2.

C. Analysis and Decision

The waiver of service obligation contained in LTIAP section 4(a)(4) addresses hydroelectric and non-hydroelectric resources separately. It is a component of the mitigation BPA requires for providing Assured Delivery service. Moreover, the provision has statutory bases.

With respect to exports of Northwest hydroelectric resources, a reduction of power supplied under the BPA power sales contract is statutorily required under the nonpermissive language of section 3(d) of the Northwest Regional Preference Act, 16 U.S.C. §837b(d). For example, Tacoma has a sales agreement with WAPA covering hydroelectric resources that make up the "SCBID project." An Assured Delivery contract covering this sale would contain a provision for waiver of BPA's service obligation during the period of the sale. Under the Regional Preference Act, Tacoma must submit a new firm resources exhibit and assured capability exhibit to its power sales contract indicating the monthly obligation of energy equal to its export sale.

Thermal exports are covered by Northwest Power Act section 9(c), 16 U.S.C. §839f(c). Section 9(c) grants the Administrator more discretion than section 3(d) of the Regional Preference Act.

PGP's qualification would only create confusion both at the time of a sale and later when an exporting utility approached us with a request for power. BPA must protect itself and our customers from any new resource obligations triggered by the export decisions of Northwest utilities. We are making a determination that utilities can conserve their surplus resources to serve future load through withdrawal provisions, transformation into exchanges, or other methods.

This is not to say that we would be precluded from serving loads of utilities that make export sales. However, such a decision would be at our option, based on consideration of factors such as net revenues, effects on our other customers and any environmental concerns. 26/

26/ Analyses in section 4.4 of the IDU EIS indicate that nonfederal utilities would develop coal-fired and, to a lesser degree, small hydro generation. Federal resource development would focus on completion of Washington Nuclear Project Nos. 1 and 3 before coal or hydro generation.

An unusual situation is presented by Cowlitz, which has an agreement with WAPA covering a thermal resource owned by Cowlitz's retail customer, Longview Fibre. Longview Fibre, sold its resource to WAPA. The waiver does not apply to Cowlitz for this transaction. Assured Delivery service would provide for wheeling this resource from Cowlitz's system to WAPA.

We do not agree with MPC that the offer of a section 9(i)(3) resource, or any other resource, to BPA should excuse the offering utility from the provisions of section 4(a)(4). Section 9(i)(3) provides only for a priority to available BPA services. It does not exempt the utility from any applicable policy or legal requirement. MPC's argument would put us in an untenable position: either (1) buy the offered resource, even though we have a large surplus for some years to come, or (2) reject the offer, thereby committing to serve the utility's load growth that could have been served by the exported resource, even after we reach load-resource balance. MPC's argument would eliminate BPA's protection from the adverse effects of long-term exports of nonfederal power resources.

Colstrip No. 4 was offered to BPA only after the Montana Public Service Commission showed an unwillingness to permit MPC to recover the costs of this resource. Instead, the commission seems inclined to have MPC provide for future load growth from other resources, including the spot market. For the moment, the commission seems to have determined that Colstrip No. 4 should not be considered as a resource needed to meet regional loads. Hence, MPC's proposed export sale may have no effect on future decisions concerning resources needed to serve Montana loads.

We do not ask MPC shareholders to absorb the costs of this idle resource by forgoing export sales. However, the problem is not of BPA's making. The region -- through BPA's customers -- should not be asked to absorb the cost if future events demonstrate that the commission should have dedicated Colstrip

No. 4 to Montana retail loads. After LTIAP section 4(a)(4)(B) is applied to MPC's 105 MW Assured Delivery contract, decisions about future resource costs will lie exclusively with MPC and the Montana commission (unless those decisions were to trigger a new application for residential exchange benefits).

In addition to the provisions for waiver of service obligation under the LTIAP, BPA is including in its Assured Delivery agreements a provision for termination of the agreement if the utility does not comply with waiver of service requirements. This should provide an additional measure of assurance that resources sold outside the region will not impact regional energy requirements, particularly after BPA is in load-resource balance.

ISSUE NO. 2: **Should utilities owning or controlling interconnections to the Southwest be required to utilize such capacity before requesting Assured Delivery capacity from BPA?**

REFERENCE: **1987 draft policy §3(d), 4(a)**
Final LTIAP §3(d), 4(a)(2), 5(c)(3), Exhibit B

A. BPA Proposal

Section 4(a) of the 1987 draft policy requires utilities to utilize their own Southwest transmission access before requesting Assured Delivery service. This requirement is in part implemented by decrementing a utility's regional surplus by the amount of the transmission capacity to the Southwest. Read in conjunction with the 1987 draft policy's definition of "Assured Delivery," this use-your-own-first requirement would apply to all interconnections, existing or future, regardless of the market served. Our intent was to make Assured Delivery service available primarily to utilities that lack interconnection capacity and therefore depend on BPA for access to the Southwest. Tr. 13.

This issue has five discrete components. First, should the requirement be adopted at all? Second, should the requirement apply to all Southwest interconnections or to only the Southern Intertie? Third, should it apply only to capacity owned or controlled as of the date an Assured Delivery request is received; or retroactively to curtail existing Assured Delivery contracts when a utility acquires new interconnection capacity? Fourth, should the requirement distinguish between the different markets served by different transmission lines? Fifth, should "use-your-own-first" apply to joint ventures with BPA?

B. Summary of Comments

WPAG states two reasons why a utility with its own interconnection would seek Assured Delivery service: "First, it may wish to reserve its Intertie capacity for other transactions, such as spot market sales. And, second, it may be that its Intertie does not connect it to a viable market, and it is only by use of the federal Intertie that it can reach interested buyers." WPAG, #3-200, p. 7. WPAG argues that neither reason is sufficient to relieve a utility from the use-your-own-first requirement. Id.

NGPU argued for retroactive application of section 4(a), "if ... utilities gain additional access through Third AC ownership their assured access through the existing BPA Intertie should be reduced an equal amount." #3-100, p. 4.

PGP supports section 4(a) "applicable only to the existing Intertie and shall not affect ownership or access of the 3rd AC line or other future transmission investments." PGP, #3-124, p. 5. In later comments PGP stated, "We recognize the appropriateness of allowing "swaps" between AC and DC access and encourage BPA to utilize this option when appropriate." PGP, #3-194, p. 3.

PGE is a co-owner of facilities in the existing AC Intertie. Its concern relates to a perceived inability to reach markets accessible only over the DC Intertie, without first utilizing its AC capacity to other markets. PGE, #3-198, p. 2. PGE also requested a clarification of whether section 4(a) would require a scheduling utility to utilize its own Intertie capacity for joint ventures. PGE, #3-133, attachment, p. 3.

Similar comments were filed by PP&L, which has firm delivery rights at Malin Substation for transactions on the AC Intertie:

> The LTIAP is not market specific, and provides better market access to non-Intertie owner utilities than to utilities with Intertie ownership or rights .... This policy would unreasonably discriminate against Pacific, which has agreed to contribute its underutilized Intertie rights to the allocation process <u>without compensation of any kind</u>." [Emphasis in original.] PP&L, #3-138, p. 1.

PSP&L comments, "The draft LTIAP's requirement that utilities use other transmission paths to the "Southwest" before receiving any Assured Delivery penalizes the development of transmission and unlawfully discriminates against utilities owning such transmission." PSP&L, #3-117, p. 12.

The Governor of Oregon supports the intent of section 4(a); however, he recommends "a compromise that recognizes the complexity of the market and the physical network of AC and DC lines." The Governor suggests that "a utility should use its own intertie capacity first but with respect to each Southwest customer, not the entire Southwest market." Governor of Oregon, #3-134, p. 2.

WWP generally favors the provision, but states, "this consideration should be prospective only and should not involve a decrement of firm Intertie capacity already under contract." WWP, #3-122, pp. 12-13.

This concern was also expressed by the CEC, who recommended that to provide long-term planning certainty for utilities with Assured Delivery agreements, BPA should apply the condition of "use your own first" only to interconnections in existence at the time an agreement for Assured Delivery is provided, not retroactively to utilities that may acquire interconnection rights or ownership after receiving an agreement for Assured Delivery from BPA. CEC, #3-218, p. 61.

Northwest utility regulators also oppose section 4(a). WUTC commented that the provision "may not promote cost-effective seasonal exchanges." WUTC, #3-92, p. 3. IPUC argued that "this would be an impossible condition to enforce and [we] recommend that BPA drop it." IPUC, #3-116, p. 4-5.

C. Analysis and Decision

We address each of the five component issues in turn: need for the provision, scope of the provision, prospective versus retroactive application, distinctions between markets, and application to joint ventures.

Need for the provision. The two existing nonfederal Intertie owners argue that the provision is unduly discriminatory. To sustain this proposition they must demonstrate that there is no material distinction between Intertie owners and nonowners for purposes of this issue. While owners and nonowners may have similar aspirations to engage in firm power transactions over the Intertie, the distinctions between them is significant.

Owners have immediate access to their transmission capacity for profit-making transactions. Any BPA Assured Delivery service to owners is cumulative of their own Intertie capacity, but a reduction of the firm wheeling available to nonowners. The nonowners are totally dependent on BPA for access; other Intertie owners do not provide long-term firm wheeling to them. More liberal access to BPA's Intertie could allow owners to capture more of the spot market over their Intertie shares while using up capacity on BPA's system at the expense of nonowners. Both effects can adversely affect BPA and its marketing program (see Part Two, Section 3, Issue 2).

It is likely that BPA would be told to use its own capacity first if it approached either PP&L or UPL for firm wheeling. In testimony before the Federal Energy Regulatory Commission on the proposed UPL-PP&L merger, UPL Vice President Verl Topham listed 16 preconditions that must be satisfied before the companies would consider providing wheeling service. Condition No. 14 is "[w]hether the party requesting the service has other reasonable opportunities available to it through other transmission paths ... ." Topham Rebuttal Testimony, p. 50, Utah Power & Light Co., Docket No. EC88-2-000 (February 24, 1988).

PP&L's claim that it has, without compensation, made its unused Intertie rights available to BPA for use under the LTIAP requires clarification. PP&L obtained 300 MW of firm delivery rights at Malin Substation as part of a general settlement of a contractual dispute and resolution of issues involved in the third AC line. Though PP&L's unused Intertie rights revert to BPA at no charge, BPA paid for this with other compromises throughout the complex arrangement.

Our primary concern in resolving this issue is to balance the needs of nonowners for firm Intertie access against the concerns of BPA and its customers about revenue impacts. BPA is providing a maximum of 800 MW of Intertie capacity to reach this balance. The concerns of owners are secondary for the reasons stated above. The LTIAP makes Assured Delivery service available to owners; however, they will be required first to utilize their own capacity for firm transactions. This conclusion is tempered by opportunities for joint ventures and transmission swaps available to Intertie owners. These options, available on a case-by-case basis, are discussed below. BPA will apply this requirement on a fair and nondiscriminatory basis. As explained below, if other utilities acquire Southwest interconnections in the future they too will be subject to the same requirements to use their capacity prior to obtaining additional Federal Intertie access. Their remaining regional surplus will also be decremented by the amount of their Intertie capacity to arrive at their Exhibit B amount.

Scope. We agree with the Idaho PUC that the draft proposal, which applies to all interconnections, would be difficult to enforce. We have no practical means of monitoring flows over Southwest interties east of the Cascades, a system controlled largely by Utah Power & Light Co. To rely on UPL representations about use of eastern Interties virtually guarantees ambiguities, which we would have no practical way of resolving.

Yet, it seems unfair to exempt UPL -- either now, or after consummation of its proposed merger with PP&L -- from the use-your-own-first requirement. UPL has substantial interconnection capacity, which should be sufficient for its Southwest marketing needs. As we understand it, enhanced Southwest market access is a major reason, if not the most important reason, UPL and PP&L propose to merge. Our solution, therefore, is to rewrite the LTIAP definition of "Scheduling Utility" to exclude the owner of this eastern system. The definition will contain the following addition: "the term excludes Utah Power & Light Company, either as a separate corporation or as a division of another corporation, because it has sufficient transmission capacity to the Southwest without access to the Federal Intertie."

This has been BPA's practice under earlier versions of the IAP. However, the change will **not** preclude Intertie access for UP&L. We leave open the possibility of transmission swaps or joint ventures between BPA and UP&L, discussed below, if commercially attractive terms can be negotiated.

The possibility still exists that interconnections may be constructed and agreements may be executed for rights to capacity in interconnections with the Southwest that can be monitored. An example of this is the PP&L right to construct and utilize parallel paths in Southern Oregon and Northern

California, for sales to California up to a total of 300 MW. BPA would require PP&L to utilize its own interconnections unless PP&L should agree to swap capacity or negotiate a separate arrangement with BPA such as a joint venture. We do not want to limit the use-your-own-first policy to BPA's existing or expanded Pacific Northwest-Pacific Southwest Intertie if either PP&L or any utility constructs a parallel facility to BPA's Intertie. This provision will remain in the LTIAP.

Prospective vs. retroactive application. WWP makes a compelling argument against retroactive application of section 4(a), interpreted consistently with the proposed definition of "Assured Delivery." If retroactivity were the rule, any utility with (1) an Assured Delivery contract and (2) an interest in constructing transmission capacity to the Southwest would face the prospect of constructing incremental capacity for both its new transactions and its existing contracts transmitted over the Federal Intertie. This result, which could frustrate the construction of new transmission capacity, does not seem necessary to achieve the basic purpose of the use-your-own-first concept. Also a consideration in our decision is the CEC's concern regarding the uncertainty in long-range planning if Assured Delivery contracts were subject to retroactive application of the "use your own first" condition. The provision on retroactive reductions is excluded from the definition of "Assured Delivery" in the final LTIAP. However, utilities obtaining new transmission capacity to the Southwest must use that capacity prior to obtaining additional access to BPA's Intertie.

Distinctions between markets. There is an incomplete overlap between the markets served by the AC and DC Interties. PGE and PP&L, with ownership limited to the AC lines, observe that the use-your-own-first requirement might block their use of Assured Delivery capacity to markets served by the DC Intertie if they had not first utilized all their respective AC capacity.

While this observation about the 1987 draft policy is correct, the solution is not to give PGE or PP&L more Assured Delivery capacity at the expense of nonowners. Instead, we will consider swaps of BPA's Intertie capacity for that of PGE or PP&L offered at commercially attractive terms. Intertie swaps and joint ventures provide another possible means of utilizing BPA's Intertie capacity, unconstrained by Assured Delivery capacity limitations in the LTIAP.

Joint ventures. Joint ventures will be negotiated in arms-length bargaining, with this issue being resolved on a case-by-case basis.

ISSUE NO. 3: **How should existing Intertie wheeling contracts be treated under the LTIAP?**

REFERENCE: **1987 draft policy §4(d)(2), Exhibit C**
Final LTIAP §4(c)(2)(A), Exhibit B

A. BPA Proposal

Exhibit A to the 1987 draft policy would extend Assured Delivery service for the remaining terms of two seasonal exchanges involving WWP and California utilities. This service is also provided until 1990 for a firm power sale from Basin Electric Cooperative to WAPA. Tacoma and Longview Fibre and Cowlitz have existing agreements with WAPA also. However, their agreements were tied to the finalization of a LTIAP.

B. Summary of Comments

Basin requests that BPA consider an extension of its contract with WAPA, "if it is in the best interest of the parties," to enable WAPA and BPA to utilize their investments in transmission facilities through the state of Montana. Basin, #3-101, p. 1.

Longview Fibre and Cowlitz have an agreement with WAPA for a 45 MW firm sale of the output of Longview Fibre Corporation's cogeneration facility. Continued wheeling is dependent on the outcome of the LTIAP. Cowlitz has requested BPA to grandfather this contract under the final LTIAP. Cowlitz, #3-129, p. 2.

Tacoma also has an agreement with WAPA with continued access tied to the implementation of the LTIAP. Tacoma comments that if this agreement had not been made with WAPA the region's surplus would have been greater and BPA's revenues would have been reduced due to Tacoma displacing the load it put on BPA. Tacoma, #3-130, p. 2.

WWP asserts that with appropriate operational mitigation its existing agreements with SCE and SDG&E should be renewed. WWP, #3-195, p. 7.

C. Analysis and Decision

BPA will increase the Exhibit B amounts for scheduling utilities Tacoma and Cowlitz so that their firm sales to WAPA may continue to receive Assured Delivery service throughout their remaining terms. Our grandfathering of these agreements protects BPA's revenues from priority firm sales to Tacoma and Cowlitz of approximately $19 million annually. This amount clearly exceeds any mitigation that might be imposed at an estimated value of approximately $1.5 million annually.

Firm access for the Basin/WAPA power sale will be provided from BPA's remaining capacity until 1990. We agree with WWP that with appropriate mitigation its agreement may be renewed if the agreements conform with the provisions of the LTIAP.

ISSUE NO. 4. **Is the requirement for return of seasonal exchanges at COB/NOB a negotiable mitigation item?**

REFERENCE: **1987 draft policy §4(d)(4)(B)(i)**
Final LTIAP §4(a)(5)

A. **BPA Proposal**

The draft policy required energy returns under seasonal exchanges to the California/Oregon border (COB) or the Nevada/Oregon border (NOB). This was initially included in the mitigation provisions for seasonal exchanges. At that time we anticipated that the operational mitigation measures were the only mitigation measures for seasonal exchanges.

B. **Summary of Comments**

PSP&L viewed the requirement as a measure imposed by BPA to enhance revenues which could result in generation in the Southwest supplanting less expensive generation in the Northwest. PSP&L, #3-117, pp. 7-8.

PG&E was also concerned with the revenue implications of COB/NOB return requirements, and stated the increased revenues would not only accrue to BPA but also would create an unjust "windfall" to other Northwest utilities. PG&E, #3-188, p. 30.

WAPA expressed concern about operational problems as well as costs, especially if the return is "during a time when the Northwest does not need the energy, in effect, exacerbating spill conditions." WAPA, #3-189, p. 2.

C. **Analysis and Decision**

BPA needs the certainty of available Intertie capacity resulting from return requirements at COB/NOB. For this reason, we include this provision in LTIAP section 4(a)(5) as a standard requirement for all exchanges.

We do not view the obligation to return exchange energy at COB/NOB as mitigation. The definition of Intertie Capacity relies on a total available north to south capacity that is not diminished by the deletion of return schedules. Operationally this means that BPA is able to allocate Intertie capacity effectively and provides the potential for an increased market. All Intertie users benefit from the certainty of available capacity for allocation.

SDG&E asked for clarification of the COB/NOB requirement, asking if it was mainly for wheeling revenue or for counterscheduling. SDG&E, Tr. 100. We replied that it provided both. BPA, Tr. 101. While this may increase wheeling and power sales revenues as a result of the increased market potential, the increased capacity also means that California will have the opportunity to buy more energy from the Northwest when it is cost effective for them to do so. The fulfillment of WAPA's concern about increased incidence of spill would be unlikely because the "present rates are designed to allow us to expand our marketing in these over-supply conditions". Tr. 36.

ISSUE NO. 5:	**What provisions for Assured Delivery will be made for extraregional utilities, including Canadian utilities, in the policy?**
REFERENCE	**1987 draft policy §1.14., §6** **FINAL LTIAP §1.15, §6**

A. BPA Proposal

For extraregional access for firm transactions the draft policy required that the utility must provide some benefit to BPA, such as increased storage, improved system coordination or operation, or other consideration of value. In addition, the utility must agree to the mitigation provisions of the policy. Canadian utilities were required to wait for access until after the Intertie was rated at 7900 MW.

B. Summary of Comments

California utilities did not want extraregional access to be delayed until after the upgrade of the Intertie system. SDG&E, #3-196, p. 2; NCPA, #3-190, p. 4; TANC, Tr. 440.

BC Hydro saw itself as worse off in the December draft of the policy than under previous drafts of the policy and objected to U.S. extraregional utilities having the potential for access prior to Canadian utilities. BCH, Tr. 449. It also requested clarification of the conditions under which BCHydro could receive access for Assured Delivery. BCH, #3-186, p. 1.

BPA anticipates that if the Free Trade Agreement is passed the distinction between U.S. extraregional utilities and Canadian utilities will evaporate. BPA, Tr. 94.

C. Analysis and Decision

If Canadian utilities are willing to provide the same items of value BPA was requiring U.S. extraregional utilities to provide prior to receiving Assured Delivery, BPA sees no reason for denying Canadian utilities access for firm transactions until after the Intertie is upgraded to 7900 MW. This provision has been deleted from the LTIAP.

No extraregional utilities, including Canadian utilities, have an allocation for firm surplus under Exhibit B. Any access they receive would be outside the 800 MW reserved in Exhibit B and would be conditioned on providing something of benefit to BPA and meeting the mitigation provisions in section 4(d). In addition, all proposals would be subject to review by BPA and the public, plus an environmental review.

Section 3. MITIGATING ADVERSE REVENUE IMPACTS

ISSUE NO. 1: **Should the LTIAP include mitigation provisions to offset adverse revenue effects of Assured Delivery service?**

REFERENCE: **1987 draft policy §4(c)(2), 4(d)(4)**
Final LTIAP §4(b)(2), 4(d)

A. BPA Proposal

The 1986 draft LTIAP proposed to make 420 MW of Assured Delivery capacity available to Northwest utilities with firm surpluses. This capacity was to be made available without regard to any adverse impact on BPA's ability to sell firm power or nonfirm energy to the same Southwest utilities. The 1987 draft proposed to make more capacity available for a greater variety of firm transactions. However, we did so in a manner that would reduce adverse revenue impacts on BPA.

"Mitigation" refers to conditions imposed on a utility in return for an Assured Delivery contract. Intertie Capacity not available to BPA because of Assured Delivery contracts can reduce BPA's revenues and thus inhibit our ability to make Treasury payments. During the operating year BPA often has power available to load the Intertie fully. Assured Delivery granted under these circumstances would reduce our revenues. We are not willing to jeopardize our fiscal responsibilities to the Treasury.

B. Summary of Comments

Benton PUD asked BPA to adopt measures that maintain rate stablility to our total requirements customers. "If BPA does decide to allow other utilities to use the Intertie, it should only be done at no net loss of revenue to BPA." Benton PUD, #3-197, p. 1. This sentiment was echoed in the comments of WPAG:

> Generating utilities find themselves in the awkward position of arguing that they wish to make export transactions which will bring substantial economic benefits to the region, but that these transactions cannot bear even a modest charge to offset BPA's foregone revenues. ... It appears that the generating utilities are attempting to shift as many transaction costs as possible to BPA and its other customers, in order to increase the benefits of export transactions to their ratepayers. WPAG, #3-210, p. 3.

Canby made similar comments. Canby, #3-162, p. 4.

EWEB comments, "BPA has a responsibility to its Priority Firm purchasers to minimize revenue losses as a result of the development of a revised LTIAP. ... Mitigation provisions must be sufficient to hold BPA and its customers harmless." EWEB, #3-200, p. 2.

NGPU comments, "[W]e do understand ... the primary focus of the interests of other parties is to shift revenues from BPA to their own utilities. Our group consists of twenty of BPA's full requirements utilities and it is our view that all of your full requirements customers would wholeheartedly oppose such a shift of revenues for the purpose of achieving regional and interregional harmony." NGPU, #3-100, p. 1. ORECA agrees and comments, "the cooperatives are mindful that the rates [BPA] charges to the cooperative consumer are largely based on BPA's revenues. This last rate case showed that when BPA's revenues dip, rate increases are imposed. That ... is not in any utility's best interest." ORECA, #3-102, p. 1.

The DSIs express concerns similar to the public utilities and comment, "The operational constraints BPA proposed initially would not fully mitigate BPA's revenue loss." DSI, #3-214, p. 2.

The DSI comments also provided an encapsulated version of BPA and PNUCC studies supporting their position: "BPA has estimated its losses for granting 800 MW of Assured Delivery at $15 million to $26 million annually or $19 to $33 per kW. With its limited operational mitigation, BPA estimates its loss would be $13 million to $21 million annually or $16 to $26 per kW. PNUCC has estimated the cost to BPA of making 695 MW available for seasonal exchanges would be as high as $25 million annually or $36 per kW." DSI, #3-214, p. 2. On the other hand, SCL considers that the results from these studies show the revenue impacts on BPA to be negligible and opposes the mitigation proposal in the policy. SCL, #3-136, pp. 1-2.

SMUD comments that while BPA's goal in the proposed LTIAP is protection of revenues, the amount of revenue BPA is attempting to recover is not enough to ensure rate stability. SMUD, #3-183, p. 3.

The CPUC asserts that if BPA is unable to collect enough revenues from California to repay the United States Treasury, BPA should collect those revenues by adjusting its rates to its customers in the Northwest. CPUC, #3-199, p. 3.

C. <u>Analysis and Decision</u>

Mitigation presents a typical allocation question: how much benefit should be conferred on each contender and at what cost to others? From the standpoint of BPA's total requirements customers, mitigation embodies the hold-harmless concept they want incorporated into the LTIAP. The DSIs, for example, argue that mitigation is legally required to offset up to $21 million in annual losses they would attribute to 800 MW of Assured Delivery capacity. DSI, #3-82; p. 5. The DSIs' legal argument springs from the statutory requirement that BPA maintain the "lowest possible rates to consumers consistent with sound business principles." 16 U.S.C. 838g, 825s.

Nothing grates on the total requirements customers more than the CPUC's argument against mitigation that "BPA need merely adjust the rates charged its customers in the Pacific Northwest." CPUC, #3-199, p. 3. Of course, the CPUC is always as extreme in its advocacy as the most strident total requirements customer. 27/ However, two basic propositions make it clear that, within this band of rhetoric, there is room for compromise.

First, mitigation is not intended to extract a profit or penalty from Assured Delivery transactions. Compare SCE, #3-187, p. 12. The concept of mitigation is quite different from the transmission pricing concept recently established in the Western Systems Power Pool, Pacific Gas & Electric Co., FERC Docket No. ER-87-97-001 PG&E ¶61,242 (1987), where profits through value-based pricing are an incentive for utilities to provide more wheeling service. We simply do not want Assured Delivery to worsen BPA's financial situation and the outlook for rate stability.

In this sense, we agree with the DSIs that mitigation is a "sound business principle" within the meaning of BPA's organic statutes. In the absence of mitigation provisions, we could not offer 800 MW of Assured Delivery. Revenue losses would force us to scale that number back. MC-88, attachment 1; PNUCC Study, Tr. 865-870. Indeed, the 420 MW number contained in the 1986 draft LTIAP might be excessive even without mitigation provisions, given concerns about the revenue implications of Assured Delivery service reflected in the 1987 draft. Commenters who find any form of mitigation unacceptable should bear this in mind.

Questions about Intertie usage always seem to involve debate about the original purpose of the Intertie. E.g., PSP&L, Tr. 479. However, the issues

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27/ CPUC criticizes BPA for failure to hold an "evidentiary hearing." CPUC, #3-199, p. 4. For one thing, this ignores BPA staff's submission to intense questioning during five days of transcribed public proceedings and an additional four days of informal discussion with California utilities and regulators. For another, it seems forgetful of the CPUC President's insistence that any public proceeding -- much less an evidentiary one -- "discourage the candor necessary" to develop a policy acceptable to CPUC. CPUC, #3-78, p. 1. CPUC has demanded that the LTIAP be developed in private meetings, apart from any process open to the public. Finally, we observe that the LTIAP is not a rate subject to hearing requirements. Bonneville Power Admin., 33 FERC ¶61,235 (1985); California Energy Commission v. BPA, 831 F.2d 1467 (9th Cir. 1987).

at hand cannot be resolved through a regression analysis of what might have been if ownership had been different, or if utilities had first concentrated on firm power transactions instead of spot-market sales. It is clear that BPA's authority to protect its revenues has been established and reaffirmed by the Ninth Circuit Court. In the final LTIAP, we have attempted to balance on a prospective basis the competing demands of generating utilities and total requirements customers and the Treasury. Mitigation is an essential part of that balance.

Second, we have been told repeatedly that interregional firm power sales and exchanges hold the promise of material benefits for the transacting utilities. NRDC, #3-132, p. 4; PG&E, Tr. 110, 427; PSP&L, Tr. 481; WUTC, #3-179, p. 1; WWP, #3-122, p. 2. However, these benefits should not come at the expense of rate increases for BPA's customers. Mitigation does nothing more than share a modest portion of the benefits made possible by Assured Delivery capacity. Generating utilities have not explained how mitigation would frustrate any beneficial transaction between the Northwest and California.

Therefore, the LTIAP includes mitigation provisions. Issues concerning particular mitigation elements will be resolved on subsequent pages of this decision. We continue to emphasize a willingness to consider departures from the generic form of mitigation, on a case-by-case basis, to accommodate unusual transactions.

ISSUE NO. 2: What specific mitigation provisions should be included in the LTIAP?

REFERENCE: 1987 draft policy §4(d)(4)
Final LTIAP §4(d)

A. BPA Proposals

It would be a false precision to claim that we could develop mitigation measures that offset dollar-for-dollar the losses projected in any 20-year study. Tr. 8. Assumptions about annual rainfall, gas prices, aluminum prices, and load growth make this exercise judgmental. Id. With this limitation in mind, we proposed the following provisions in the 1987 draft policy.

The first mitigation measure was to require that during any hour in which prescheduled energy sales are made under Condition 1 Formula Allocation procedures, a utility must deduct its Assured Delivery amount from its Formula Allocation. If a utility's Assured Delivery amount was greater than its Formula Allocation, then that utility must purchase enough energy from BPA to make up the difference. This mitigation measure was intended to offset most of the spot market revenues lost by granting Assured Delivery. This proposal was based on comments received on the 1986 draft LTIAP.

Other mitigation was included for Seasonal Exchanges. The 1987 draft policy contained two provisions, in addition to the above mitigation, that would apply to seasonal exchanges. One was a requirement for return of all seasonal exchanges at COB or NOB. The other mitigation measure specific to seasonal exchanges was the limitation on cash-out provisions 28/ of an exchange contract. If BPA invoked Condition 1 or Condition 2 allocation procedures, cash-out provisions of seasonal exchange contracts would become

28/ Cash out provisions of Seasonal Exchange contracts allow a Northwest utility to accept dollar payments from a Southwest utility in lieu of actual energy returns.

inoperative. This mitigation measure was proposed to increase the north-to-south capability of the Intertie during Conditions 1 and 2 when energy is returned and to increase the size of the market for spot-market sales.

B. Summary of Comments

BPA received a large number of comments suggesting other means of mitigation or a mix that provides a menu of options. The following is representative of these suggestions.

Southbound Deliveries (the first measure). BPA's primary concern is the loss of spot market transactions resulting from Assured Delivery transactions. During Condition 1, utilities would utilize their Formula Allocation for their Assured Delivery transactions and, if their Formula Allocation was insufficient to cover those transactions, they would purchase the difference from BPA. This measure is one way to hold us harmless from an intrusion on our share of the spot market. BPA, Tr. 10.

The DSIs are concerned that this would not be sufficient to hold BPA harmless and suggest that Condition 1 mitigation be extended to Condition 2. DSI, Tr. 37.

Instead of guaranteeing BPA the revenue from these purchases, WAPA thinks BPA should open this opportunity to all Northwest utilities with a Formula Allocation and suggests that BPA should allow the ability to "buy from any utility, including BPA, that has a surplus." WAPA, #3-189, p. 2.

PG&E essentially agrees with WAPA in regard to the ability to buy from other Northwest utilities to cover a deficiency. However, PG&E would put BPA last in the queue of sellers. PG&E, #3-188, p. 30.

PSP&L comments in regard to the amount of energy BPA may sell as a result of Condition 1 mitigation, "the amount of energy subject to mitigation could be increased significantly, and may even exceed the amount which Bonneville could otherwise have sold." PSP&L, #3-117, p. 8.

SDG&E does not object to a requirement to purchase the difference between the allocation and the Assured Delivery amount but is concerned with the uncertainty of the price. SDG&E, #3-196, p. 2.

SCE thinks that Assured Delivery should be in addition to a utility's Formula Allocation. SCE prefers "no penalty, mitigation or infringement" on any Assured Delivery contract and does not like the uncertainty of what the additional costs might be or when they might be imposed. SCE, #3-187, pp. 12-13.

Cash-out Limitations. The purpose of cash-out limitations in the 1987 draft policy was to allow BPA and other utilities to participate in the market created by the returns in Condition 1 and 2. BPA, Tr. 52. Otherwise, exchanging utilities could seize much of the spot market through exchanges, even though their Formula Allocations might be small. Analysis shows that with mitigation BPA is still negatively impacted, even on the spot market, from the seasonal exchanges. BPA, Tr. 58.

EWEB agrees and points out that this provision not only protects BPA but also protects the ability of non-exchanging nonfederal utilities from a loss of potential nonfirm markets. EWEB is concerned that replacing this mitigation provision with a surcharge would eliminate the benefit to nonfederal utilities. EWEB, #3-137, p. 2.

PG&E is concerned that nonfederal utilities such as EWEB would share in the benefits while not participating in the exchanges. PG&E views the cash-out provisions as only revenue devices, "with no link to alleged adverse effects of Assured Delivery." PG&E, #3-188, p. 30.

WPAG itemized the benefits BPA might realize from a nonfederal seasonal exchange that would be reduced by cash-out provisions, including "wheeling revenues, winter return energy sales revenues, counter-scheduling and [construction] deferral of regional resources." WPAG, #3-123, p. 11.

WAPA comments that cash out limitations could cause "the exchanger to generate and return energy during a time when the Northwest does not need the energy, in effect, exacerbating spill conditions." WAPA, #3-189, p. 2.

PSP&L comments that the cash-out restriction would benefit BPA by increasing wheeling revenues but would not pass those credits on to the exchangers. PSP&L, #3-117, p. 7-8.

ICP views mitigation of the southbound deliveries plus a mitigation of the return of that delivery as a double benefit to BPA, which "removes a potential, major benefit of exchanges and attempts to create a market for Bonneville by force." ICP, #3-119, p. 9.

Other Mitigation Suggestions. PGP comments, "The PGP supports mitigation for real costs (and real benefits) incurred as a result of Assured Delivery transactions ... and encourage the development of a menu of options (contractual, operational, financial, etc.) which may be used, on a case-by-case basis, to ensure compensation for either BPA or nonfederal utilities incurring costs as a result of the transaction." PGP, #3-194, p. 9.

NGPU includes in its comments another alternative:

> The two mitigation measures proposed in the LTIAP are complex and even then only return on the order of 20-25 percent of BPA's losses. However, it is our view that although it may be difficult to negotiate a simple cash reimbursement to BPA based on each transaction, that concept needs to be seriously investigated. Another alternative is a system access fee "to recoup projected losses from those parties that are profiting by accessing the Intertie. [NGPU, #3-100, p. 3.]

PNGC comments, "[T]he LTIAP should permit utilities to negotiate mitigation with BPA on a case-by-case basis. Moreover, mitigation should not be required if providing Assured Delivery will have a neutral or positive effect on BPA's revenues." PNGC, #3-141, p. 3.

The following entities are in favor of case-by-case mitigation: NGPU (Tr. 494); PNGC (#3-141, p. 3); SCL (Tr. 501); TANC (#3-182, p. 2); WPAG (Tr. 515); WWP (#3-122, p. 19); and PPC (#3-125, p. 3).

C. **Analysis and Decision**

This issue points out to BPA the individual nature of each utility and the need for flexibility in the LTIAP, particularly in the LTIAP provisions for mitigation. We include in the LTIAP an opportunity for utilities to pick the best form of mitigation for their needs. Operational mitigation is still in the policy as an option (section 4(d)). However, the requirement for delivery of returns of energy at COB/NOB has been moved as a condition for access to section 4(a) and is not viewed as mitigation. This is discussed in more detail in the Conditions for Assured Delivery Access section, Issue 4.

We have decided to include an opportunity for utilities to negotiate individual packages of mitigation, in addition to the mitigation provisions in the LTIAP in section 4(d). Such case-by-case mitigation packages could be a combination of the above mitigation provisions or could include beneficial arrangements for BPA that have not been addressed in this policy. Our main concern in any mitigation package is recovery of short-term revenue impacts, but we will also be looking at the operational impacts of any proposal.

We have also changed the requirements for purchasing from BPA any difference between a utility's Formula Allocation and its Assured Delivery requirement. During Condition 1 a utility may purchase from any utility with an allocation, not just BPA. During Condition 2, the utility must first purchase from BPA, and if BPA is not in the market then may purchase an allocation from other utilities with an allocation. This change gives utilities more flexibility and should not harm us with the current true up arrangements provided under Condition 1 allocation procedures.

ISSUE NO. 3: **Should BPA provide scheduling utilities with a mitigation charge alternative?**

REFERENCE: **1987 draft policy - no reference**
Final LTIAP §4(d)(2)

A. BPA Proposal

We did not propose a mitigation charge in any draft of the LTIAP.

B. Summary of Comments

The concept of a surcharge was introduced during the public process. WAPA favors the idea of a surcharge and suggests it be developed through the ratemaking process. It suggests that the surcharge be based on a determination of BPA's lost revenue and be included as an option to operational mitigation. WAPA, #3-189, p. 2. MPC comments, "If BPA insists on mitigation, it should do so by simply charging a reasonable fixed surcharge in addition to the cost of the facilities." MPC, #3-111, p. 3.

IPC supports a surcharge approach, claiming that it is an antidote to the uncertainty facing some utilities that wish to negotiate Assured Delivery contracts without the ability "to fairly determine financial liability and exposure to mitigation costs up front ... ." IPC, #3-131, p. 2. In a similar vein, PPC supports a surcharge because of its simplicity. PPC, #3-125, p. 1.

The DSIs see the surcharge as an opportunity for BPA to recover the total loss of revenue associated with nonfederal usage of the Intertie. The DSIs recommend a surcharge in addition to operational mitigation. DSI, #3-82, p. 2.

WPAG comments that if BPA provides access it must receive mitigation that fully compensates it for any revenue losses. WPAG recommends a charge based on current and future losses. WPAG suggests the charges could be different for firm power sales and seasonal exchanges. WPAG, #3-123, p. 7.

SCL does not agree with the DSIs and WPAG that a surcharge be added to the existing mitigation measures. SCL comments, "Again, there is skepticism as to the real costs and benefits that BPA and its customers may incur as a result of allowing non-federal utilities access." SCL, #3-210, p. 3.

SDG&E comments, "The Policy contains numerous operational mitigation measures which we believe unduly complicate system operations. ... SDG&E suggests that the policy contain an option of a surcharge in lieu of operational mitigation." SDG&E, #3-196, p. 2. LADWP agrees with SDG&E. LADWP is concerned with the uncertainty of proposed mitigation in the draft policy but "still believes that imposition of any fees in excess of cost based transmission service rates violates BPA's obligation to provide Intertie access to nonfederal utilities." LADWP, #3-192, p. 2.

WWP opposed the surcharge. WWP, #3-122, p. 19. EWEB comments that it would not favor a surcharge if it would take the place of the cash-out provision because the cash-out provision protects EWEB's ability to make nonfirm sales. EWEB, Tr. 930.

C. Decision

The concept of a surcharge was attractive to BPA and several utilities. However, the procedural requirements of Northwest Power Act section 7(i) would require considerable time unless all interested parties agreed not to intervene in the process. BPA advanced the proposal in a prehearing and received considerable negative response. Therefore BPA has decided to drop the proposal at this time. This does not prevent BPA from developing charges on a case-by-case basis.

Section 4. Canadian Treaty Power

ISSUE: **Should the LTIAP make express provision for Canadian Treaty power?**

REFERENCE: **This issue is not addressed in the policy.**

A. Proposal

PG&E requests that the policy expressly provide transmission service for transactions by which British Columbia might dispose of downstream power benefits to which the province is entitled under the treaty between Canada and the United States relating to development of Columbia River hydro resources. Such transactions are referenced in section 6 of the Northwest Preference Act.

B. Response

Several reasons cause us to defer this question until it becomes less speculative.

First, the province would not be in a position to sell its downstream power benefits to California until 1998, at the earliest. The benefits were previously sold to U.S. utilities under 30-year contracts that do not begin to expire until 1998. Thereafter, these benefits revert to British Columbia over a 6-year period.

Second, at this time, it is impossible to quantify the benefits that will revert to the province. We simply do not know the magnitude of Intertie transmission service we might be called on to deliver.

Third, it is not clear whether the province will decide to sell the downstream benefits in new contracts after 1998. It might decide, instead, to use the benefits to satisfy native load growth within the province.

Fourth, until negotiations between the province and potential U.S. buyers are concluded, we have no idea what form possible transactions might take. Downstream benefits might be shaped into firm power sales or exchanges, or even nonfirm transactions, each with a distinct impact on Federal usage of the Intertie.

All these reasons cause us to distinguish the PG&E transmission request from the relatively certain requests for Assured Delivery capacity made by utilities in the Northwest and California. Moreover, additional research is required on the status of any Canadian entitlement priority after existing entitlement sales terminate. Each Assured Delivery request is supported either by an executed contract or by a proposed transaction for which a contract is now being negotiated. We will leave the question about Intertie access for British Columbia's downstream power benefits for a later version of the LTIAP.

PART FOUR

FISH AND WILDLIFE PROVISIONS

"PROTECTED AREAS"

ISSUE NO. 1: **Should we adopt the "protected area" concept as a means of satisfying our fish and wildlife responsibilities?**

REFERENCE: **1987 draft policy §7(c)**
Final LTIAP §7(c)

A. BPA Proposal

We included fish and wildlife provisions in the near-term and proposed long-term policies to protect the investments we have made and will continue to make to protect, mitigate, and enhance fish and wildlife in the Columbia River Basin. Since passage of the Northwest Power Act, our ratepayers have invested nearly $120 million in habitat, passage, hatchery, and projects to meet the Council's interim goal of doubling anadromous fish runs in the Columbia River Basin. In addition to these expenditures, BPA annually forgoes $30 to $60 million in revenues due to the implementation of the Water Budget and spill programs. These programs improve flow and passage conditions for migrating juvenile salmon and steelhead; they also reduce electric generation on the Federal hydro system.

We do not want the LTIAP to encourage hydro operations or developments that compromise our investments in the Columbia Basin. We also hope to discourage hydro developments that, by creating passage or habitat problems, increase the cost of our future investments.

To achieve these objectives, the 1986 draft policy established procedures by which complainants could notify us if a particular resource was harming fish or wildlife. However, utilities, fish and wildlife agencies, and tribes generally argued that the 1986 draft procedures were ineffective. Their concerns centered on two problems.

First, the procedures allowed challenges to hydro projects well after the licensing process was completed. Consequently, a developer could undergo the expense of the FERC licensing process, meet FERC's fish and wildlife requirements, and still be denied Intertie access after BPA's subsequent procedure. Developers disliked the uncertainty and fish and wildlife interests disliked the lengthy procedures.

Second, the 1986 draft proposed enforcement mechanisms seemed ineffective. Fish and wildlife interests believed the LTIAP would allow projects to support sales over the Intertie even though they were harmful to fish or wildlife.

The 1987 draft policy sought to accomplish our objectives with a much simpler mechanism, the "protected area" concept. As presently proposed by the Northwest Power Planning Council, protected areas are specific stream reaches withdrawn from hydro development due to the presence of high-value wildlife and anadromous and high-value resident fish. Stream reaches may also be protected where future investments in habitat, hatchery, passage, or other projects may result in the presence of anadromous fish. The LTIAP's proposal differed from the Council's proposal in that protected areas would be restricted to stream reaches within the Columbia River Basin -- the proposed Council designations cover the entire Pacific Northwest.

The 1987 draft policy automatically reduced a utility's access to the Intertie if it built or acquired a project located in a protected area. Our choice of the protected area concept sought to address utilities' concerns about the uncertainty of BPA actions, eliminate lengthy procedures that could increase development costs, and establish an effective enforcement mechanism.

B. Summary of Comments

We received more comments concerning the use and scope of protected areas than any other provision in the policy. A vast majority of commenters -- many of them private citizens -- support BPA's adoption of the protected area concept. NMFS, which had previously criticized our implementation of fish and wildlife provisions in the NTIAP, states: "Unlike previous draft and interim policies, the new policy provisions concerning fish and wildlife are clear, unambiguous, easy to administer, and enforceable." NMFS, #3-120, p. 1. Similar comments are made by NRDC [#3-132], which had previously criticized the near-term policy.

Commenters generally agree that the IAP can influence the operation and development of hydroelectric resources in the Northwest. "Clearly, the intertie has, and likely will continue to, serve as an incentive to new hydro development in the Northwest. It is thus quite appropriate that BPA should include provisions in the LTIAP that prevent the intertie from being an incentive for inappropriate resource development ... ." Friends of the Earth, #3-202, p. 2. NRDC states, "... no one can dispute that the export markets associated with Intertie access exert potent influence over decisions about developing and operating resources." NRDC, #3-132, p. 1. This view is shared by the Idaho Attorney General. IAG, #3-126.

ICP does not specifically dispute the connection between the IAP and hydro development, but states: "We have yet to hear of a single case in which a nonfederal development has impacted BPA costs." ICP, #3-119, p. 9.

PNUCC does not dispute the connection between the IAP and hydro development. It states that it "is willing to talk about some method in which BPA can ensure that its Intertie is not inappropriately used as a justification to construct new resources that we wouldn't allow be constructed in the region without the Intertie." PNUCC, Tr. 735.

PNUCC proposes alternative fish and wildlife provisions which are endorsed by several commenters. The PNUCC proposal provides for BPA to conduct a project-by-project determination and deny access if BPA determines that a proposed project adversely impacts BPA fish and wildlife investments, adversely impacts other BPA fish and wildlife responsibilities, or impairs BPA's ability to comply with provisions in the Council's Fish and Wildlife Program. PNUCC, #3-135, Attachment 1.

Although utilities recognize that the IAP could affect hydro development and operations, they state that FERC license requirements and procedures are sufficient to prevent hydro operations and developments harmful to fish and wildlife:

> While we applaud BPA's apparent goal of protecting fish and wildlife as well as the Administrator's actions or expenditures related to these resources, there is no need for BPA to take actions which are in addition to hydroelectric project licensing and license review procedures established by the Federal Energy Regulatory Commission (FERC). PP&L, #3-138, p. 3.

IPUC suggests that "[i]f BPA determines there will be negative impacts on its fish and wildlife investments from hydro projects it should oppose construction based on its own analysis or submit a mitigation proposal during the existing FERC licensing." IPUC, #3-116, p. 2. Similar comments are made by WWP. WWP, #3-122, pp. 14-16.

In addressing BPA's legal authority to include fish and wildlife provisions, NRDC concludes, "FERC regulation is no substitute for the unique BPA/Council commitment to double the Columbia Basin's devastated fish runs, in response to the mandate of the Pacific Northwest Electric Power Planning and Conservation Act." NRDC, #3-132, p. 3.

Similar comments are made by WPAG, which states: "BPA has an independent responsibility to determine where it has made fish and wildlife investments, and whether proposed resource development located in the Columbia Basin will adversely impact these investments." WPAG, #3-123, p. 20. And SCL, with generating capabilities of its own, states: "... we understand and support the potential for reducing access to the Intertie if new hydroelectric resources are developed in environmentally sensitive (Protected Areas) locations." SCL, #3-136, p. 3.

However, LADWP questions why fish and wildlife provisions were included in the IAP at all. It suggests that we adopt a fish and wildlife policy that would deny access to any BPA transmission facility. "If power from a resource cannot be delivered within the Northwest, or to the Intertie, it's not necessary to address the problem in the IAP." LADWP, Tr. 639. Similar comments are made by CEC. CEC, #3-218.

Several other utilities question the relevance of fish and wildlife measures to the LTIAP. "Edison believes that BPA should not use the LTIAP to be the mechanism for implementing its fish and wildlife objectives." SCE, #3-187, p. 28. Similarly, PSP&L argues:

> Access to Intertie capacity cannot and should not be restricted by perceived fish and wildlife impacts of generating resources or based on compliance with licenses, permits, or laws in connection with the development or operation of generation resources. Bonneville has no authority to impose such restrictions on Intertie access. PSP&L, #3-117, p. 9.

Several commenters suggest that BPA eliminate specific reference to protected areas and merely ensure that the policy be consistent with the Council's Fish and Wildlife Program. CRITFC states, "We believe that the LTIAP should recognize and rely upon the Council's Program and Plan for the protection of fish and wildlife with respect to access to the BPA controlled portions of the Intertie." CRITFC, #3-204, p. 1. Similar views are expressed by the Idaho Attorney General [#3-126].

But PGP disagrees. "We do not believe that consistency with the plan or program is necessarily the appropriate question, that instead, BPA should evaluate whether or not a project will adversely affect or reduce the effectiveness of the Administrator's investment in fish and wildlife." PGP, #3-194, p. 12.

NRDC addresses the issue of whether BPA should act on the protected area concept before the Regional Council decides whether to adopt a protected area program:

> The database used to designate "Protected Areas" is hardly the exclusive province of the Council; indeed, BPA itself funded and helped staff the effort. It is hardly unreasonable for BPA initially to frame its Policy by reference to environmental information that BPA collaborated in assembling. Once the Council has acted, BPA pledges to issue conforming Policy amendments, 'subject to BPA review of Council changes.' This seems a reasonable exercise in cooperative federalism. NRDC, #3-132, p. 6.

Many other commenters support the inclusion of fish and wildlife provisions, including Northwest Members of Congress [#3-142]; the Idaho Attorney General [#3-126]; the Governor of Montana [#3-127]; the Governor of Oregon [#3-134]; the State of Washington Utilities and Transportation Commission [#3-92]; and the Washington Departments of Fisheries [#3-113] and Game [#3-152].

C. Analysis and Decision

We know of no alternative to the protected area concept that satisfies our administrative objectives of practicality and clarity. No such alternative has been suggested by commenters. The choice is between the protected area concept and removal of fish and wildlife protective measures from the LTIAP.

We believe the protected area approach provides the best assurance for fish and wildlife protection with the least amount of procedural duplication and uncertainty. Protected area designations would send an unambiguous, self-enforcing message to FERC, other regulators, and hydro developers that no

Intertie access will be provided for projects constructed in areas of greatest concern to BPA and the Council. Southwest market access could not be reflected in any accurate assessment of need for a project.

Our protected area designations are made with sufficient analysis by BPA, the Council, and others. The data include:

- Anadromous fish data collected by state and Federal fish and wildlife agencies and tribes under Council direction.
- Resident fish and wildlife data collected by state and Federal fish and wildlife agencies and tribes and interested parties such as hydro developers as part of the BPA-funded Pacific Northwest Rivers Study.
- The Pacific Northwest Hydropower Data Base and Analysis System, which includes detailed information about 4,000 potential and existing hydro projects. This information was obtained using FERC data through a joint effort by BPA, the Council, and the Corps.

We made available to the public a complete listing of the proposed protected areas in the 1987 draft. During the comment period we received no objections to any specific river or stream reach designated as a protected area.

The PNUCC proposal would involve a process similar to the one BPA proposed in earlier IAP drafts and which many previous commenters, including utilities, found objectionable. However, the final IAP has been revised to address several concerns raised by PNUCC and others. These revisions are discussed below as specific issues raised by the implementation of the protected areas concept.

BPA has never disputed FERC's regulatory role in addressing fish and wildlife concerns. The Electric Consumers Protection Act (ECPA), 16 U.S.C. §797(e), may have provided FERC with increased fish and wildlife responsibilities. However, ECPA does not require FERC to protect BPA investments in fishery enhancement. From time to time as FERC considers specific hydro projects, BPA has participated, and will continue to participate, in those proceedings based on fish and wildlife concerns. But

BPA has its own specific statutory responsibilities that focus on its own fish and wildlife investments.

We have distinct statutory responsibility to protect, mitigate, and enhance fish and wildlife. The authority to include fish and wildlife provisions in the LTIAP was recently supported by the Ninth Circuit Court, California Energy Commission v. BPA, 831 F.2d 1467, 1477-78 (9th Cir. 1987). We believe that exclusive reliance on FERC intervention may not provide sufficient protections for BPA's fish and wildlife investments. FERC has no explicit statutory mandate to protect those investments and may ultimately license projects that could negatively affect those investments.

Standards contained in the Northwest Power Act are more definitive than FERC's mandate under ECPA. Despite the different statutory mandates, the LTIAP does not preempt the FERC role. It is intended to ensure that we are able to meet our fish and wildlife goals and ensure the productivity of our fish and wildlife investments. Furthermore, as a Federal agency we are required to consider how we may, in the course of taking major actions, promote, preserve, or enhance the quality of the human environment. Id.

By designating specific stream reaches where habitat supports high-value wildlife and anadromous and high-value resident fish, BPA seeks to assist FERC and hydro developers as they evaluate sites before they devote any resources to the development of a project. The LTIAP recognizes that FERC may override these concerns. Although FERC is directed to consider state and regional fishery management plans such as the Council's Fish and Wildlife Program and to provide equitable treatment to fish and wildlife under 4(h)(11)(A) of the Northwest Power Act, and to provide "equal consideration to fish and wildlife under ECPA, FERC must also consider other factors in making its determinations.

LADWP is correct that BPA could fashion alternatives, such as a main transmission grid policy, to address its fish and wildlife concerns. However, even if we chose to adopt such an alternative, the basic issues raised by implementation of such a policy would remain. Extraregional sales would be affected and differences in opinions concerning FERC's role would persist.

ISSUE NO. 2: **Should protected area designations be restricted to the Columbia River Basin?**

REFERENCE: **1987 draft policy § 1(13)**
Final LTIAP § 1(14)

A. <u>**BPA Proposal**</u>

Previous versions of the IAP restricted the fish and wildlife provisions to new and existing hydro projects in the Columbia Basin. We continued this focus in the 1987 draft, which proposed to designate protected areas only within the Columbia River Basin. The 1987 draft differed from the Council's proposal which would designate protected areas throughout the Northwest.

B. <u>**Summary of Comments**</u>

Nearly all of the comments BPA received supporting the use of protected areas also suggest that we extend the IAP protected area designations to the entire Northwest. Support for regional protected areas is based on the concern that if restrictions are applied only within the Basin, BPA would encourage development outside the Basin. "We fear that if you do not apply your policy to all of the Protected Areas in the State of Washington, hydro developers will put enormous pressure on the river resources outside the basin." Sierra Club, #3-155, p. 2.

Many commenters suggest that increased development outside the basin would threaten BPA's interests inside the basin: "From the perspective of damage to the Northwest's anadromous fishery, hydropower development <u>outside</u> the

Columbia River Basin is potentially a larger problem than in-Basin construction. ... Hydropower-related reductions in out-of-Basin runs translate inexorably into increased fishing losses for in-Basin runs." NRDC, #3-132, p. 5.

The Northwest Power Planning Council states:

> The Council believes that the reasons for giving consideration to fish and wildlife within the basin apply equally to the region outside the basin. While questions can be and are raised with respect to the Council's authority to deal with fish and wildlife outside the basin, no such restriction impinges on BPA action and we believe some further attention to Intertie access conditions outside the basin is in order. NWPPC, #3-139, p. 1.

Similar comments are made by NMFS [#3-120], Friends of the Earth [#3-203], NCAC [#3-216], the Governor of Oregon [#3-134], several Northwest Congressional representatives [#3-142], and members of the general public.

A significant number of commenters, including the Council, suggest that we simply commit to mirroring the Council's designations: "... if Bonneville intends to rely on Council protected areas, we believe that Bonneville should not rely on some parts and exclude others." NWPPC, #3-139, p. 1.

Commenters who oppose the protected area concept also oppose designating areas outside the Basin. "The presumption that out-of-Basin development of hydroelectric resources will have 'potentially devastating fishery consequences' is extremely dramatic and misleading." PNUCC, #3-202, p. 4.

Some utilities comment that BPA's role inside the basin differs from outside the basin. The Canby Utility Board comments:

> We do believe Protected Areas in the IAP should be limited to the Columbia Basin (BPA does not have responsibilities or investments in fish outside the Basin), to salmon and steelhead (resident fish and wildlife are being restored on an ad hoc basis which is incompatible with a comprehensive approach such as Protected Areas) and to new projects (mitigation for existing projects are [sic] established by license conditions and the Fish and Wildlife Program). Canby, #3-162, p. 3.

Similar comments are made by SCL [#3-136].

C. Analysis and Decision

The effect on anadromous fish returns in the Columbia Basin from hydro development outside the Basin is indirect. In addition, we see no evidence that significant increases in fishery damage will occur outside the Basin if BPA does not impose restrictions on Intertie access for projects located in the Council's protected areas outside the Basin. Those projects would still be addressed by BPA, Council, and agency comments during the FERC licensing process. As provided by ECPA, FERC must provide equal consideration to fish and wildlife and must provide substantial deference to state agency recommendations.

BPA's mandate is to protect, mitigate, and enhance fish and wildlife in the Columbia Basin. It is our conclusion that the risk of significant harm occurring to BPA's fish and wildlife investments in the Basin from hydro development outside the Basin is unproven on the record. We wish to restrict BPA's regulatory presence to risks which are substantial.

The LTIAP does not reflect a lack of concern about hydro development outside the Basin. If we determine that a project outside the basin poses a threat to existing or planned BPA fish and wildlife investments, we will intervene in the FERC process.

ISSUE NO. 3: **Should BPA categorically deny access to all projects located in protected areas?**

REFERENCE: **1987 draft policy §7(a)**
Final LTIAP §7(e)

A. BPA Proposal

The 1987 draft policy denied Intertie access categorically for projects located within protected areas. The policy presumed that any development in those areas would harm fish and wildlife and detract from BPA's investments and the Council's goals. The 1987 draft sent a clear signal to developers and avoided a time-consuming, staff-intensive, and possibly duplicative review of the biological effects attributed to any hydro project.

B. Summary of Comments

Many of the comments concerning this issue contend that BPA should provide a means by which project developers can challenge the presumption that particular projects located in protected areas harm fish and wildlife. For example, PNUCC proposes that BPA conduct a project-by-project determination and deny access if BPA determines that a proposed project adversely impacts BPA fish and wildlife investments; adversely impacts other BPA fish and wildlife responsibilities; or impairs BPA's ability to comply with provisions in the Council's Fish and Wildlife Program (including protected areas). PNUCC, #3-135, Attachment 1. PNUCC's proposed alternative fish and wildlife provisions are endorsed by several other commenters. PGP states:

> If BPA's goals are to have the least intrusive role possible while sending utilities the clearest message, couldn't BPA's policy state that BPA will not grant any access to a resource that it finds is a "bad resource?" ... A "bad resource" is any resource in a protected area in the Columbia Basin for which the utility cannot demonstrate that it will hold BPA harmless for its fish investments and cannot demonstrate that the resource will do no damage to fish runs. PGP, Tr. 766.

Northern Wasco PUD also recommends that sites be considered individually and access granted or denied on the merits of each site. "(T)here are sites that can be developed with no or minimal harm to the fishery. We feel it is unrealistic to preclude development at these sites with a blanket 'protected area' designation." Wasco, #3-085, p. 1.

IPUC comments that we should review individual projects and suggest how impacts we identify might be mitigated. "If BPA determines there will be negative impacts on its fish and wildlife investments from hydro projects it should oppose construction based on its own analysis or submit a mitigation proposal during the existing FERC licensing." IPUC, #3-116, p. 2.

On the other hand, many of those supporting the use of protected areas comment that the concept should bar the construction of hydro projects. For example, "if all the interested parties would work together in support of Protected Areas and the LTIAP, new hydro projects simply would not be built in Protected Areas." Friends of the Earth, #3-203, p. 2. But NRDC states: "It should also be possible to exempt projects from protected areas if they would enhance or at least not harm fish." NRDC, Tr. 738.

Several commenters continue to suggest that BPA should not concern itself with putting specific provisions in the IAP but merely ensure that access be granted only to projects that are consistent with the Regional Council's program.

C. Analysis and Decision

We agree that categorically denying access to hydro projects located in protected areas may discourage projects which might advance the Council's Program or our investments. Consequently, we have revised the policy to provide a limited opportunity to review proposed developments to determine if the prohibition should apply. However, we believe very few of the projects proposed in protected areas will provide increased seasonal flows, improved passage, or other conditions which could provide benefits to BPA's investments or the Council's Program. This provision is intended only as a safety valve.

The policy would continue our original intent: access to projects located in protected areas will be denied. But if we receive sufficient proof that a project will actually benefit existing or planned BPA fish and wildlife investments or the Council's Program and will have no significant adverse environmental effects, we may reconsider this prohibition.

Our determination would be based on information including: agreements with Federal and state fish and wildlife agencies and tribes; action by the Regional Council; and any technical information which would quantify the benefits attributed to the proposed project. We do not propose to establish explicit standards that define the degree to which a project must contribute to BPA's or the Council's fish and wildlife goals. We recognize that additional information concerning a project's fish and wildlife effects may become available during the FERC licensing process.

In a related issue, the 1987 draft policy did not provide a process to consider if a particular stream reach is improperly designated as a protected area. However, the policy indicates that BPA would reevaluate protected area designations as new information becomes available or as the Council acts. We believe the policy adequately reflects suggestions that we provide an explicit process to address technical issues concerning the designation of protected areas.

ISSUE NO. 4: **How should BPA coordinate provisions concerning protected areas with the Northwest Power Planning Council?**

REFERENCE: **1987 draft policy §7(b)**
Final LTIAP §7(c)

A. <u>BPA Proposal</u>

As we developed the 1987 draft policy, we considered ways in which we could provide in our decisions for consideration of the Council's Program. The 1987 draft policy noted that implementation of the LTIAP might precede adoption of the Council's protected area program but provided for BPA to re-evaluate protected area designations once the Council adopted or modified its proposal.

We have identified two related issues concerning coordination with the Council. First, what provisions, if any, should be included in the IAP given that the Council has not yet, and conceivably may never, designate protected areas? Second, assuming that the Council does adopt a protected area program, what provisions should we include to address changes the Council might adopt over the years as protected areas are implemented?

B. <u>Summary of Comments</u>

Several commenters state that BPA should not adopt a protected area program until after the Council acts. "It is premature for BPA to adopt the staff's proposed protected areas criteria when the Council has not even accepted the criteria. ... It is premature for BPA to act when the Council has not acted." PNUCC, #3-202, p. 3; <u>see</u> WPAG, Tr. 396.

Canby Utility Board disagrees:

> BPA can use the existing data bases to designate stream reaches supporting salmon and steelhead as Protected Areas even if the NW Power Planning Council does not. We believe that this would be far preferable to alternatives - such as 'consistency with the NPPC Program' - which are too broad and create too much uncertainty. Canby, #3-162, p. 4.

The Council encourages us to reconsider the policy once it has acted:

> ... Bonneville would be on sounder footing in relying on a Council proposal as criteria for Intertie access rather than a staff proposal. We appreciate that Bonneville would review its protected areas based on the outcome of the Council's rulemaking process. NWPPC, #3-139, p. 1.

C. Analysis and Decision

The LTIAP provides a sufficient indication that BPA will consider the Council's protected area designations when finalized. We will "implement, after review and possible modification, a comprehensive protected area program adopted by the Pacific Northwest Electric Power and Conservation Planning Council." LTIAP Section 7(c). We have clarified this language to indicate our willingness to consider the Council's protected area program once it is adopted and is revised with the implementation of planning efforts in the future. We have also revised the policy to provide for BPA consideration of appropriate state comprehensive water plans affecting hydro development.

We considered but rejected a "sunset clause" which would have terminated the fish and wildlife provisions if the Council chooses not to adopt a protected area concept. We determined that a sunset clause would not contribute to the Council's deliberations and would leave BPA with insufficient protection for our fish and wildlife investments.

ISSUE NO. 5: **Should the IAP fish and wildlife provisions apply to existing projects?**

REFERENCE: **1987 draft policy §7(a)**
Final LTIAP eliminated

A. BPA Proposal

The 1986 draft LTIAP proposed for BPA to determine if the operation of existing hydro projects resulted in a "substantial decrease in the effectiveness of, or a substantial increase in the need for, expenditures or other actions by the Administrator to protect, mitigate, or enhance fish and wildlife ... ." The 1987 draft policy proposed that if an existing project was located in a protected area, at the time of license expiration, "BPA would assist the licensee in developing any necessary protective conditions so that the project may continue to qualify for Intertie access." Section 7(a).

We included provisions applicable to existing resources because we believed those projects can harm BPA's fish and wildlife investments in the Basin. For example, by altering flow regimes or neglecting fish bypass systems, a hydro project could significantly increase mortality of fish produced by BPA-funded hatchery or habitat projects upstream.

B. Summary of Comments

BPA received extensive and diverse comments concerning access to the Intertie for existing hydro projects. While some commenters support provisions applicable to existing projects, not one commenter supports the 1987 draft policy provisions. Several utilities claim FERC is uniquely charged with reviewing the fish and wildlife effects at the time existing projects are relicensed. PNUCC, #3-202, p. 2.

Many commenters, including the Council, state that the proposed protected area program is not intended to apply to existing hydro projects. For example, the Governor of Oregon states:

> The fish provisions should apply to new hydro projects but not to existing dams. For existing dams the proposed penalty is extreme and does not reflect the cost imposed on the fish program. Problems at existing dams should be settled in the FERC arena. Governor of Oregon, #3-134, p. 2.

The Idaho Attorney General [#3-126], NWPPC [#3-139], and others claim that BPA should not rely solely on FERC but that we should not apply our own fish and wildlife standards to existing hydro projects. They suggest that BPA rely on consistency with the Council's Program.

> We recommend that the IAP simply require consistency with the Columbia River Basin Fish and Wildlife Program as a pre-condition to Intertie access. The conditions for existing resources are predictable because they are set forth in the program. Idaho Attorney General, #3-126, p. 2; see NWPPC, #3-139, p. 2.

Utilities generally endorse the Council's view that protected areas should not be applied to existing projects:

> The protected areas concept as envisioned by most parties, if not all, has been intended to apply exclusively to presently undeveloped stream reaches and not to modification or relicensing of existing projects ... . The present proposal to impose sanctions upon existing, non-Federal projects which happen to fall within a protected area is directly in conflict with the intended applicability of this concept. WWP, #3-122, p. 15.

Many commenters who oppose the use of protected areas for existing resources also do not believe any provisions should be applied. WWP cited the uncertainty created by potentially denying access to existing resources:

> WWP continues to oppose loss of access for regulatory events which are beyond WWP's control and which occur after firm access has been granted, such as FERC relicensing conditions, or future action by the Northwest Power Council to adopt new protected area designations in originally unprotected stream reaches. WWP, #3-195, p. 3.

NCAC suggests that BPA enforcement should be applied to existing projects only when they fail to meet hydro operations requirements, such as flow regimes, contained in the Council's Program. NCAC, #3-206, p. 3. NCAC's reasoning appears to be that access to the Intertie could likely induce non-compliance with requirements such as maintaining flow levels. NCAC concludes that BPA should allow access if an existing project does not conform to structural requirements, such as the installation of bypass structures.

Some commenters agree that the draft policy would create undesirable uncertainty during the relicensing process, but they suggest that BPA's reliance on the Council's Fish and Wildlife Program would eliminate this uncertainty:

> It's important for the contracting parties to have a clear understanding of what the expectations are on relicensing. There is a way for them to get that, if the relicensing provisions are keyed to the Council's F&W program, where you can find out exactly what the obligations are. NRDC, Tr. 701.

Several commenters also suggest that BPA deny access to Federal as well as non-Federal projects that do not conform to the Council's program. NMFS comments: "Federal as well as non-Federal projects should be covered by the IAP in the interest of fish and wildlife protection." NMFS, #3-120, p. 3. NMFS also suggests that BPA should deny access to existing projects that do not "meet full protection/mitigation/compensation requirements." NMFS provides a list of projects it believes create fish and wildlife problems.

While comments suggest that access be denied to existing projects not in conformance with the Council's Program, those comments do not indicate the procedures BPA should follow to determine if a particular project is not in compliance. NMFS suggests that, "imposition of the fish and wildlife provisions of the IAP should not be delayed until the time of relicensing, which may not occur for decades." NMFS, #3-208, p. 1.

The Council argues that we should not wait for FERC relicensing:

> The Council believes that, because the fish and wildlife program is in place, consistency determinations could be made in the near term. The program's measures are clear, and the Council is committed to monitor and amend the program so that the program's measures and timetables remain appropriate and realistic. The Council would work with Bonneville to develop a process for making consistency determinations. NWPPC, #3-213.

C. Analysis and Decision

The Council is clear that the protected area concept is not intended to cover existing hydro resources. We agree. The issue then becomes a question of whether the LTIAP should go beyond protected areas to become a general enforcement mechanism for the Council's Fish and Wildlife Program. Beyond legal concerns, we have basic questions about the practicality of such a role.

The Columbia River Basin Fish and Wildlife Program explicitly relies on FERC for enforcement of program measures calling for operational and structural changes at existing non-Federal hydro projects. Other measures direct project operators to work with fish and wildlife agencies to study fish and wildlife problems and consider possible corrections. We do not propose to assume the role of arbitrator between the Council and these other agencies.

For example, Program measures involving FERC will be addressed in licensing proceedings under the Federal Power Act. FERC will either adopt the measure or reject it. Dissatisfied parties then have judicial recourse before the Court of Appeals. If FERC erred, the court will remand proceedings for further administrative action. There is no role for BPA here as a second fact-finding, administrative tribunal.

We believe the fish and wildlife provisions applied to existing resources should be viewed differently than provisions applied to new resource development. For new resources, a utility can easily avoid the impact of the

LTIAP provisions merely by avoiding projects in designated protected areas. We do not intrude into the FERC licensing process; our decision about Intertie access is known to FERC and the hydro developer before that process begins.

While we agree there is a potential for existing projects to harm BPA fish and wildlife investments, we do not believe there is sufficient evidence to indicate that existing projects are presently operating contrary to the Council's Program or that the Council has been unable or unwilling to implement Program measures applicable to existing projects.

NMFS presented a list of 16 projects with fish and wildlife concerns, but NMFS did not show how those projects conflicted with the Council's Program. The Council provided no evidence that existing projects are in violation of its Program or that the Council had attempted but was unable to rectify problems with FERC's implementation of the Program.

We agree with utility concerns that it will be difficult to negotiate long-term power sales contracts that rely on the Intertie when those contracts can be negated through subsequent action of government agencies. Furthermore, we believe this uncertainty is too great a price to pay, since the Council, fish and wildlife agencies, and tribes can rely on other procedures to ensure that existing projects comply with the Council's program. Given the divisiveness of this issue, the lack of explicit program language applicable to BPA, and the Council's opportunities to work with FERC, we are reluctant to apply the LTIAP to existing hydro projects.

Finally, the LTIAP was never intended to apply to Federal projects. The Council's program already addresses fish and wildlife concerns at these projects. Measures such as the installation of bypass systems depend on Congressional funding; we never proposed to apply the LTIAP based on budgetary decisions over which we have no control.

ISSUE NO. 6: **Should the IAP provide an exemption for PURPA projects?**

REFERENCE: **1987 draft policy None**

Final LTIAP §7(b) and §7(e)

A. <u>BPA Proposal</u>

BPA's 1987 draft policy did not recognize any special situation involving hydro projects developed under the Public Utility Regulatory Policies Act of 1978 (PURPA). Utilities raised concerns that PURPA may require them to purchase power from protected area hydro projects developed by others.

B. <u>Summary of Comments</u>

The PURPA issue generated many comments from utilities. They are concerned that the 1987 draft policy could reduce Intertie access as a result of actions that utilities could neither avoid nor control.

Several utilities request an exception for PURPA projects. "This aspect of the draft LTIAP must be corrected by exempting Scheduling Utilities from Intertie access reductions where the output of the project in question is acquired under PURPA." WWP, #3-122, p. 14. "Should a PUC decision force a utility to accept an environmentally damaging PURPA resource, BPA should not penalize that utility for the PUC's decision." PNUCC, #3-202, p. 2.

Potential purchasers in California also express concern about the uncertainty provided by our 1987 draft policy. NCPA states:

> Our interest is in making firm power purchases -- long-term firm purchases. But with this policy, we could easily find ourselves in a situation where we have entered into contracts with Pacific Northwest utilities only to find that they are unable to make good on those contracts because they've ... become involved in a project in a protected area or worse yet, they have been forced to purchase QF power from a protected area. NCPA, Tr. 438.

But other commenters argue that providing a blanket exemption would defeat the purpose of BPA policies that seek to prevent licensure and forced purchase of PURPA project power. "Part of what makes forcing a PURPA resource on a utility so improbable is the automatic withdrawal of Intertie access--the automatic reduction in avoided cost that the minimally rational regulators will impose." NRDC, Tr. 671.

NRDC believes that PUCs should deduct the cost of reduced Intertie access from a utility's avoided cost under PURPA, making it highly unlikely that a PURPA hydro project would be constructed. WUTC agrees:

> ... it is our view that revenue losses associated with the reduced access to the Intertie would lower the avoided cost that a utility would pay for a hydro resource developed in a protected area. We would take the 'total system' approach to calculating avoided costs and recognize that any hydro resource developed in a protected area would result in a loss of benefits associated with use of the Intertie. As a regulatory agency, our response to BPA's proposed policy would be to adjust the avoided costs to reflect these lost benefits. We believe this will result in a limitation of the resources that would be developed in 'protected areas.' WUTC, #3-179, p. 3.

But this view is not shared by the IPUC, which claims: "It is unreasonable for BPA to put PUCs into the position of reconciling conflicting Federal regulations." IPUC, #3-116, p. 3.

The Governor of Oregon identifies several problems with adjusting the avoided cost to reflect a reduction in Intertie access, but concludes: "However, if the penalty provision is retained, the OPUC will make its best efforts to adjust avoided costs to reflect the cost of the penalty to the utility." Governor of Oregon, #3-134, p. 3.

Several utilities state that PUCs are not required to reduce an avoided cost to reflect reduced Intertie access. "The fact is that there is no assurance that the commissions will use their discretion in the manner suggested by the WUTC and, even if the present commissions do, that future commission will continue to do so." ICP, #3-181, p. 3.

NMFS commented that very little adjustment in avoided costs would be necessary, since, "'avoided costs' are now relatively low compared with the costs of new hydro development and construction. The provisions of the IAP, specifically the automatic decrement requirement, should help to ensure that avoided costs remain relatively low." NMFS, #3-74, p. 2.

C. Analysis and Decision

There has been much discussion of possible conflicts between the protected area provision and obligations imposed on utilities by PURPA. This concern is based on a suspicion that state PUCs cannot reflect loss of Intertie access in either the "avoided cost" rates paid to PURPA resource developers or administrative decisions on obligations to interconnect with, and purchase from, PURPA resources.

We conclude from the written comments of the WUTC that the conflict may be overstated. If one PUC has sufficient legal authority to accommodate protected area considerations in its decisions under a Federal statute, we conclude that other state regulators have similar discretion. Any state regulator declining to reflect protected area considerations in its PURPA decisions must therefore have concluded that ratepayers are better off with protected area resources -- even at the expense of reduced Intertie access.

If this conflict is real, it will affect only investor-owned utilities. Public systems are self-regulated in the Northwest and, under PURPA, make their own decisions about avoided cost rates and obligations to purchase. It is implausible that public systems will acquire protected area resources at full avoided-cost rates, exposing themselves to diminished Intertie access.

We believe the policy can be crafted to satisfy concerns about PURPA projects without eliminating the disincentive to hydro development in protected areas. A new section 7(e)(1) has been added to the LTIAP. 29/

ISSUE NO. 7: How should the protected area provision be enforced?

REFERENCE: 1987 draft policy §7(c)
Final LTIAP §7(b) and §7(d)

A. BPA Proposal

Under the 1986 draft policy, utilities were required to declare the generating resources used to support an Assured Delivery contract. If any of those resources were challenged and found to harm fish and wildlife, BPA would

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29/ The new provision reads:

> "PURPA Projects. BPA will entertain requests that it not enforce the provisions of section 7 in situations where an investor-owned utility has been compelled to acquire the output of a Protected Area hydroelectric resource under section 210 of the Public Utilities Regulatory Policies Act (PURPA). To qualify for this exception, the investor-owned utility must demonstrate:
>
> (A) that it has exercised all opportunities available under federal and state laws and regulations to decline to acquire the output of the Protected Area resource in question;
>
> (B) that it has petitioned its state regulatory authority(ies) to reduce the rate(s) established under PURPA for purchases from Protected Area resources in recognition of the increased costs or reduced revenues caused by operation of section 7(c) of this policy;
>
> (C) that BPA was provided reasonable notice of all relevant regulatory and judicial proceedings to allow for timely intervention in such proceedings; and
>
> (D) after taking all of the foregoing steps and exhausting all reasonable opportunities for judicial review, that it was compelled to acquire the output of a Protected Area hydroelectric resource by final order of FERC or a state regulatory authority issued under PURPA.

reduce future Assured Delivery or Formula Allocations by an amount equal to the capacity of the offending resource. The 1986 draft LTIAP did not propose to reduce a utility's existing Assured Delivery contracts. The 1986 draft did not explicitly result in reduced Intertie access if BPA and the utility could not agree on a means to reduce fish and wildlife damage.

Fish and wildlife agencies disliked these provisions for three reasons. First, the policy did not apply decrements to existing contracts, allowing a utility to support out-of-region sales with a hydro project that harmed fish. Second, although a utility declared the resources used to support its transactions, we provided no means to monitor these declarations. Third, a utility could blunt the effects of decrements by "over-declaring" its resources available for export.

The 1987 draft policy attempted to address these concerns. First, the policy applied an automatic reduction to any utility that built or purchased power from a hydro project located in a protected area. Consequently, it was not necessary to declare resources used to support exports or for BPA to monitor those declarations. Second, decrements were imposed on any transaction utilizing the Intertie during Formula Allocation Condition 1.

B. <u>Summary of Comments</u>

California utilities are concerned that Northwest sellers might violate the policy's fish and wildlife provisions in the future, causing an unanticipated loss of power that the buyers are counting on to meet domestic requirements. For example, LADWP comments:

> The party that bears the ultimate risk of a decrement of Assured Delivery is a California purchaser of a long-term firm product from a PNW utility. The idea of entering into the transaction in the first place becomes less attractive. LADWP, Tr. 141.

According to NRDC, the solution is to incorporate those provisions in the contracts themselves, coupled with commitments by the sellers to pay the additional costs of any replacement power that a California utility might be required to purchase as a result of a fish and wildlife violation. NRDC, #3-132, p. 5.

Other commenters maintain it is necessary to apply decrements to existing contracts to provide adequate protection for fish and wildlife:

> PNUCC continues to hold a position which would allow a utility to conclude a firm sale, and gain firm access based on an existing surplus and then develop "fish-killer" resources to support the sale. We continue to insist that the enforcement mechanism must deter such development by promising to decrement allocations for existing contracts, as well as for proposed new contracts, if the utility develops resources in violation of the fish and wildlife provisions of the policy. NCAC, #3-206, p. 2.

Similar comments are made by the Idaho Attorney General. IAG, #3-126, p. 1.

Several utilities suggest that we not apply a decrement to Formula Allocations. For example:

> Bonneville's proposal to reduce the formula allocation by the full amount of any new hydroelectric capacity in a Protected Area is an arbitrary and severe penalty based on the erroneous assumption that all of the output of the project in the Protected Area would be the power which would otherwise be transmitted on the Intertie. PSP&L, #3-117, p. 11.

CRITFC and others object to eliminating decrements applied under Conditions 2 and 3:

> From the standpoint of fish and wildlife protection, it is just as important that the deterrent value of access proscriptions be applied to conditions 2 and 3, as it is that they be applied to condition 1. CRITFC, #3-204, p. 4.

C. Analysis and Decision

In keeping with our decision to utilize the protected area concept in the LTIAP, enforcement mechanisms should be easy to administer and relatively noncontroversial. Automatic reductions to Condition 1 allocations appear to satisfy these objectives. Because of the relationship between Assured Delivery and Formula Allocation capacity created by the LTIAP mitigation provisions, this means that long-term firm transactions are potentially affected as well as spot-market sales.

Now that we have created an exception for protected-area projects that are forced upon utilities under PURPA and eliminated coverage of existing hydro resources, any uncertainty for long-term utility transactions should be minimal. Sellers and buyers have adequate means to reduce uncertainty. Buyers may insist on contract language obligating Northwest sellers to refrain from constructing hydro projects in protected areas.

It makes little sense to impose protected area decrements in Conditions 2 and 3. Under the experiment established by LTIAP section 5(d), it would be difficult to impose decrements when utilities cease to receive pro-rata shares of Intertie capacity. Consequently, the LTIAP provides for decrements only under Condition 1 when we have identifiable allocations for each utility. However, if section 5(d) is not continued after its 18-month experimental period, we may reopen the policy to apply decrements to allocations made under Conditions 2 and 3.

PART FIVE

OVERALL EFFECTS OF THE LONG-TERM INTERTIE ACCESS POLICY

It should be apparent from the foregoing discussion that resolving long-term policy issues has been an exercise in balancing conflicting expectations about how benefits and burdens of the Federal Columbia River power and transmission systems should be allocated among various interest groups. Each group wants more for itself, usually at the expense of other contenders. Each group supports its claim by referencing a favorite statutory provision or excerpt from legislative history.

Northwest interests vary among public and investor-owned generating utilities; nongenerating utilities and aluminum companies that purchase their total power requirements from BPA; and groups especially concerned about fish and wildlife protection. Some generating utilities want more transmission capacity for long-term power transactions with California. Others emphasize a demand that long-term transactions not interfere with their desire to utilize the Intertie for short-term, spot-market sales. Nongenerating utilities and the aluminum companies are wary of any non-Federal usage of the Intertie, fearing that this would reduce BPA's power sales and thereby increase our rates to them. Energy-intensive aluminum producers are especially concerned about keeping the price of their product competitive on world markets. Environmental interests want to ensure that no one's demands are satisfied in ways that jeopardize fish.

In California, utilities and regulators want access to more of the Federal Intertie for a greater variety of firm power transactions. They want "pro-competitive" access for spot-market transactions, while overlooking the existing anticompetitive practices on the California portion of the Intertie.

At the Federal level, the Office of Management and Budget insists that BPA take steps to ensure prompt repayment of its Treasury obligations. There is a serious concern that BPA actions, at the very least, not exacerbate the Federal deficit. We have stated clearly throughout the development of the IAP that one of our main goals has been to help BPA repay the U.S. Treasury. This position has been judicially upheld in Department of Water & Power v. BPA, 759 F.2d 684 (9th Cir. 1985). However, parties still disagree about the role BPA should take in managing and operating the Intertie to meet its fiscal goal.

Few of the demands made on us are typical of those a non-Federal utility would expect to honor. Each utility and customer group looks to the Intertie to support its own revenues or lower its costs. Environmental groups advance important agenda as well. And, Congress seems disinclined to forgive any of its $8 billion loaned to the Northwest's Federal power system.

The sum of all these demands far exceeds the finite limitations of the resource. In fact, many of the demands are mutually exclusive. This sometimes subtle, yet important, point must be appreciated to better understand the complex nature of the balance we have reached in the LTIAP.

Two tables discussed below demonstrate this balance of benefits. Table 1 is drawn from section I.3 of the Intertie Development and Use Environmental Impact Statement (IDU EIS). It shows the 20-year distribution of benefits based on three different alternatives: no Intertie access policy, the LTIAP, and a Federal-first policy. This long-term analysis is more meaningful than an individual-year showing, which could be significantly distorted by weather or other short-term phenomena.

Several conclusions about the balance of competing interests are evident from this table. We believe Table 1 shows that the LTIAP achieves a sense of equity between the regions and among customer groups, while maintaining our ability to meet BPA's obligations to the Treasury.

TABLE 1
Intertie Access Policy Alternatives
Comparison of Firm and Nonfirm Benefits

	Pre-IAP 1/ $000,000	%	LTIAP 2/ $000,000	%	Federal-First $000,000	%
BPA 3/	3063	32	3630	37	4394	46
PNW Non-Federal	360	4	1237	12	538	6
Total PNW	3423	36	4867	49	4932	52
California	5504	58	4438	45	3992	42
Canada	599	6	599	6	574	6
Total	9525	100	9904	100	9497	100

1/ Assumes Federal Marketing contracts (1550 MW).
2/ Assumes 800 MW of Assured Delivery contracts (1950).
3/ Assumes BPA receives 60 percent of PNW secondary revenues in the Pre-IAP and Proposed options and 70 percent in the Federal-First option.

First, Table 1 shows that we have not maximized Federal revenues in the LTIAP compared with revenues that might be achieved under a Federal-first policy. Increased Intertie usage by non-Federal utilities comes at the expense of our total requirements customers and, if the DSIs or other elements of the Northwest economy falter, the U.S. Treasury. However, both our customers and the Treasury are better off under the LTIAP than they would be if no policy were adopted.

Second, the LTIAP produces a closer sharing of benefits between the Northwest and California (49 percent vs. 45 percent) than would be the case absent a policy (59 percent vs. 35 percent). Disparity of benefits was a major concern expressed by the CEC. CEC, #3-218, pp. 36-38; see pp. ___, above.

The LTIAP interregional balance is not the exact parity, which PG&E suggested would be ideal. PG&E, #3-188, DFI appendix, p. B-3. We doubt that exact parity would be realistic or that a claim of exact parity would be credible. However, two elements of the policy not reflected in Table 1 should move us even more in that direction. The LTIAP's section 5(d) experiment should reduce Northwest benefits and increase California benefits (this will tend to be offset by removal of restrictions on usage of California's portion of the Intertie). Also, our offer to pursue share-the-savings pricing could have a similar result. Neither of these two elements is capable of reliable quantification at this time.

Third, benefits to Northwest non-Federal utilities increase under the LTIAP relative to both the "pre-IAP" and "Federal-first" alternatives. Part of this improvement is explained by the availability of Assured Delivery service; part is due to Formula Allocation procedures. We expect the latter effect to be tempered by the section 5(d) experiment.

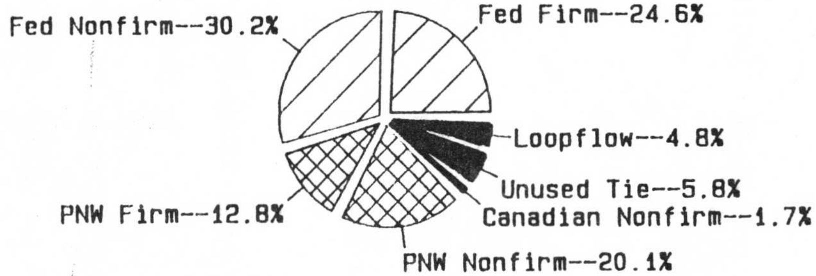
Fourth, Canadian access remains constant over the three alternatives. However, opportunities for increased long-term and short-term access are made available under section 6 of the LTIAP.

Table 2 is a set of pie charts that summarize a study BPA recently made to show expected usage of the Intertie -- by BPA, Northwest utilities and Canada --- for long-term and short-term transactions. The year 1992 was used for this analysis. For purposes of comparison, three different amounts of Assured Delivery service (0 MW, 400 MW, and 800 MW) have been assumed. This comparison tracks the evolution of Assured Delivery service from the near-term to the interim and, finally, the long-term access policy.

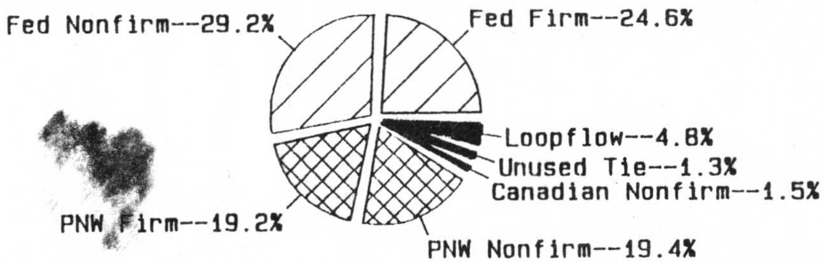
Table 2 clearly shows the shift in usage from Federal to non-Federal as we make more Assured Delivery service available for long-term interregional power transfers. This increased Assured Delivery service also comes at the expense of non-Federal utilities that deal only in the spot market.

Intertie Use
Terminal Expansion
June 1992

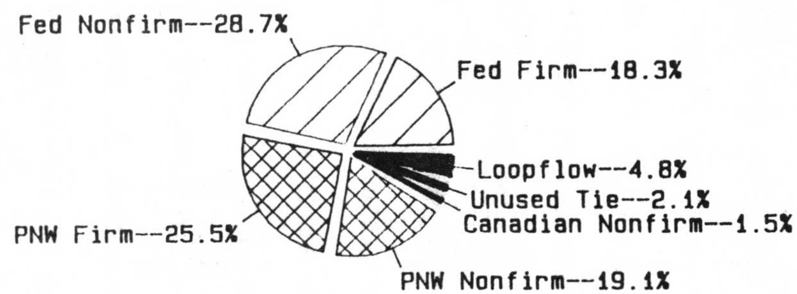
Table 2



0 MW
Assured Delivery



400 MW
Assured Delivery



800 MW
Assured Delivery

We should address two additional points not reflected in Table 2. First, non-Federal usage may increase beyond 800 MW after we revisit the demand for long-term, firm wheeling as promised in LTIAP section 4(c)(1). Second, as noted above, Canadian utilities may gain access for long-term firm or spot-market sales under LTIAP section 6.

In summary, the LTIAP by necessity is a compromise solution to the conflicting demands placed on the Intertie. No one customer group, including BPA, receives all that it may want or may believe is statutorily guaranteed. Each group, however, receives an equitable and fair share.

* * *

I have reviewed and hereby approve this decision to adopt the Long Term Intertie Access Policy appended hereto.

Issued in Portland, Oregon, May 17, 1988.

James J. Jura

James J. Jura
Administrator

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

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
MAY 17, 1988

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.

FINAL 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 authority to act, consistent with sound business principles, to recover revenue adequate to amortize 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 covers BPA's obligations to provide an adequate, reliable, economical, efficient, and environmentally acceptable power supply, while preserving public preference to Federal power. In the Southwest, the Administrator's Power Marketing Program covers activities to market surplus Federal power at equitable prices, while preserving regional and public preference to Federal power, and to assist in marketing Northwest nonfederal power.

3. "Allocation" means the share of the Intertie Capacity made available for short-term sales of energy.

4. "Assured Delivery" means firm 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 in 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.

5. "Available Intertie Capacity" is defined as the physically available capacity controlled by BPA, reduced by the capacity reserved under Section 2 of this policy and the capacity necessary to satisfy Assured Delivery contracts not subject to operational mitigation requirements under this policy.

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.

6. "BPA Resources" means Federal Columbia River Power System hydroelectric projects; resources acquired by BPA under long-term contracts; and resources acquired pursuant to section 11(b)(6)(i) of the Federal Columbia River Transmission System Act.

7. "Exchange" refers to various types of transactions that take advantage of diversity between Northwest and Southwest loads through deliveries of firm power, at prespecified delivery rates, from North to South during the Southwest's peak demands and returns of capacity and/or energy from South to North during other times. Transactions vary depending on the lag between deliveries and returns. A "naked capacity" transaction might require off-peak energy returns within 24 hours, whereas a seasonal exchange might call for firm power returns within 6 months.

8. "Extraregional Utilities" are generating utilities, or divisions thereof, that do not provide retail electric service and do not own or operate significant amounts of generating capacity in the Northwest.

9. "Formula Allocation" means the process by which Intertie Capacity made available 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.

10. "Intertie" means the two 500-kv alternating current (AC) transmission lines and one 1000 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.

11. "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).

12. "Mitigation" refers to the requirements imposed by BPA on a utility in return for an Assured Delivery contract. Mitigation helps offset operational and economic problems, attributable to a Scheduling Utility's firm power transaction, that inhibit BPA's ability to generate revenues. The Mitigation measures specified in this policy must be included in all Assured Delivery contracts, unless a scheduling utility either agrees to a specially designed charge or negotiates substitute measures with BPA on a case-by-case basis.

13. "Nonscheduling Utility" means a nonfederal Northwest utility that owns a Qualified Northwest 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.

14. "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.

15. "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.

16. "Qualified Extraregional Resource" 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 portions of units covered as Qualified Northwest Resources.

(b) after BPA 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.

17. "Qualified Northwest Resource" excludes BPA Resources, but includes:

(a) Resources located inside the Northwest that are in commercial operation as of the effective date of this policy.

(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

(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.

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.

18. "Resource" means an electric generating unit or stack of particular electric generating units identified to supply power or capacity for sale over the Intertie.

19. "Scheduling Utility" means the Northwest portion of a nonfederal utility that operates a generation control area within the Northwest, or any utility designated as a BPA "computed requirements customer." The term excludes Utah Power & Light Company, either as a separately owned company or as a division of another corporation, which has sufficient transmission capacity to the Southwest without access to the Federal Intertie.

20. "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.

21. "Section 9(i)(3) resource" means a Scheduling Utility resource that BPA has granted priority in receiving BPA transmission, storage and load factoring services as defined in §9(i)(3) of the Northwest Power Act.

Section 2. Intertie Capacity Reserved for BPA

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 2. Intertie Capacity Reserved for BPA

The Administrator reserves for BPA's use Intertie Capacity sufficient to:

(a) transmit all of BPA's surplus firm power and to serve other obligations,

(b) perform obligations, including, but not limited to, the existing transmission contracts listed in Exhibit C, to the extent such obligations differ from the conditions specified in this policy,

(c) provide Assured Delivery service for transactions not subject to limits under Exhibit B to this policy, and

(d) satisfy firm obligations that have not been prescheduled, by using unutilized portions of Formual Allocation amounts.

Section 3. Conditions For Intertie Access

(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 3. Conditions For Intertie Access

(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 Pacific Northwest-Pacific Southwest Intertie capacity or to other transmission lines to California or the Southwest market must fully utilize such capacity prior to receiving any access to BPA's Intertie Capacity. If a Scheduling Utility with Intertie rights needs BPA Intertie Capacity to reach a particular Southwest utility, BPA will consider negotiated swaps of capacity to accommodate such requests.

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.

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 limited Assured Delivery to Scheduling Utilities without causing substantial interference with the Administrator's Power Marketing Program.

(a) General Provisions

(1) Existing Transmission Contracts. BPA will provide Assured Delivery for the remaining terms of the firm power sale and Seasonal Exchange contracts identified in Exhibit C to this policy.

(2) Utilities Owning Or Controlling Southwest Interconnections. Assured Delivery is intended primarily for Scheduling Utilities which lack interconnections with the Southwest. Except for transactions covered by section 4(b) of this policy, a utility with capacity on an intertie, through contract or ownership, must utilize all such capacity on a firm basis before receiving any Assured Delivery.

(3) 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.

(4) Waiver Of BPA Service Obligation

(A) Hydroelectric Resources. Assured Delivery contracts that facilitate the export disposition of Northwest hydroelectric energy shall provide, under 16 U.S.C. §837b(d), for a reduction of BPA's power sale contract obligation to the Northwest utility, for the period of the disposition, equal to the amount of energy for which Assured Delivery is provided.

(B) Thermal Resources. Assured Delivery contracts that facilitate the export disposition of Northwest thermal energy shall provide, under 16 U.S.C. §839f(c), for a reduction of BPA's power sale contract obligation to the Northwest utility, for the period of the disposition, equal to the amount of energy for which Assured Delivery is provided. Such reduction shall become effective at the time BPA determines that it has reached energy load/resource balance, or at a date as specified in the Assured Delivery contract.

(5) Exchange Contracts. 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.

(6) Satisfying Requests For Assured Delivery. All relevant power contracts must be presented for review no later than the date on which a request for Assured Delivery is made.

(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.

(b) New Transactions Not Subject To Capacity Limits

(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.

(3) Conditions. A Scheduling Utility may request at any time the Assured Delivery of transactions identified in sections 4(b)(1) and 4(b)(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.

(c) Transactions Subject To Capacity Limits Under This Policy

(1) Maximum Amounts Of Assured Delivery. BPA will provide 800 MW of Assured Delivery for firm power sales and Exchanges identified in this policy. BPA will reassess the amount of Assured Delivery capacity when the 3d AC Intertie project is either completed or abandoned. Moreover, the 800 MW amount may be subject to some reduction if the DC Terminal Expansion project is not completed on schedule.

(2) Exhibit B amounts

(A) 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. BPA will reserve capacity equal to each Scheduling Utility's Exhibit B allocation subject to section 4(c)(2)(D) below. Except for Montana Power Company (MPC), Tacoma City Light, and Cowlitz County Public Utility District, 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

(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.

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. Exhibit B amounts for Tacoma and Cowlitz are increased to accommodate existing firm power transactions.

(B) 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.

(C) Other uses of Exhibit B amounts. BPA will not entertain Assured Delivery requests for firm power sales in excess of a utility's Exhibit B maximum. However, a Scheduling Utility may use any portion of its Exhibit B maximum, not used for firm power sales, for exchange transactions supported by Qualified Northwest Resources.

(D) Future changes. BPA may, at its discretion, revise Exhibit B to reflect changes in the firm power surpluses of individual utilities; however, the Exhibit B average firm surplus total is not subject to increase. Any unutilized Assured Delivery amount will be 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.

(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.

(3) Other Capacity. The remaining capacity available for Assured Delivery under this policy is offered to Scheduling Utilities, on a first-come, first-served basis, for Exchange transactions supported by Qualified Northwest Resources. When section 4(c)(2)(D) of this policy is implemented to reduce the Exhibit B maximum of any Scheduling Utility, the reduction will be added to the capacity made available under this provision. Any utility with an Exhibit B amount must exhaust such capacity before requesting Assured Delivery under this provision.

(d) Mitigation

(1) Operational Mitigation

(A) Southbound deliveries. During any hour in which BPA has invoked Condition 1 or Condition 2 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 make up the difference by purchasing sufficient energy as follows:

(i) during Condition 1 from BPA or any Scheduling Utility with a Formula Allocation during that hour;

(ii) during Condition 2 from BPA, however, if BPA is not in the market the utility may purchase sufficient energy from any other utility.

(B) Northbound returns. During any hour in which BPA has invoked Condition 1 or Condition 2 allocation procedures, a utility may utilize the cash-out provisions of an Exchange contract only by reducing one-for-one the amount of North-to-South Intertie capacity otherwise available to it under this policy. The rate of cash out during any condition shall not exceed the rate at which the exchange return could have been scheduled.

(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.

(2) Negotiated mitigation. A Scheduling Utility may also elect to negotiate with BPA on a case-by-case basis a package of mitigation measures involving mutually agreeable consideration of value commensurate with the service provided.

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:

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, in determining Available Intertie Capacity during Condition 1, BPA will not consider the Assured Delivery contracts to the extent they are subject to operational mitigation requirements. 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) Protected Area Decrements. Except as provided in section 4(d)(2)(A) of this policy, BPA will reduce each Scheduling Utility's allocation by any Protected Area decrement imposed pursuant to section 7(d).

(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 hydro system is in spill or there is a 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) <u>Condition 2</u>

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) <u>Condition 3</u>

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.

(i) 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.

(ii) During Condition 1, whenever BPA is unable to utilize its full pro rata share of intertie usage BPA will take larger allocations on ensuing days until the difference in pro rata intertie usage is eliminated.

(2) <u>Condition 2</u>

(A) 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.

(B) If BPA sales drop below 75 percent of its allocation during Condition 2, BPA may take larger allocations on ensuing days until the difference is eliminated.

(3) <u>Condition 3</u>

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 first to U.S. Extraregional Utilities and then to other Extraregional Utilities. Section 3(d) of this policy shall not apply to Scheduling Utilities during Condition 3.

(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.

(d) Formula Allocation Experiment. BPA is interested in exploring the proposal that it cease making individual Formula Allocations to Scheduling Utilities under Conditions 2 and 3. However, BPA must work with Northwest and Southwest utilities to develop the information capability to accommodate a new scheduling system for nonfederal access. As soon as this can be accomplished BPA will substitute the following provisions for section 5(c) on an 18-month experimental basis:

(1) Condition 1

Same as section 5(c)(1).

(2) Condition 2

(A) When Condition 1 is not in effect, but BPA and Scheduling Utilities declare amounts of energy that exceed available Intertie capacity, the Formula Allocation for BPA will approximate, by hour, the ratio of BPA's declaration to the sum of all declarations, multiplied by the Available Intertie Capacity. The remaining capacity will be made available as a block to Scheduling Utilities. Section 5(c)(2)(B) of this policy shall apply.

(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's allocation will equal its declaration. The remaining Intertie capacity will be made available, first, as a block to satisfy the declarations of Scheduling Utilities, second, to U.S. Extraregional Utilities, and third to other Extraregional Utilities. Section 3(d) of this policy shall not apply during Condition 3.

(e) Data Collection and Evaluation. Commencing when this policy goes into effect and continuing during the course of the experiment described in section 5(d), BPA will collect information on the following topics relevant to future allocation procedures:

(1) effect on BPA revenue of allocating to nonfederal utilities as a group rather than individually.

(2) impairment of Intertie access for California utilities presently lacking ownership in the southern portion of the Intertie,

(3) any loss of sales to BPA due to a failure to share unused capacity among California entities with ownership or contractual interests in the Intertie,

(4) effects of the experiment on small Scheduling Utilities.

During the course of the experiment, interested parties may submit written comments and recommendations on these issues.

(f) Findings and conclusions. At least 30 days before the end of the experiment described in section 5(d), BPA shall publish a report of its findings on the experiment and its decision on whether section 5(d), with possible modification, should be continued as the permanent method of Formula Allocation.

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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 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), must include benefits to BPA such as increased storage, improved system coordination or operation, or other consideration of value commensurate with the services provided. Proposed contracts would be evaluated by BPA and reviewed publicly to determine whether they 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 Qualified Extraregional Resources has access to the Intertie. In addition, BPA may provide Extraregional Utilities with Formula Allocation under other conditions, if the utility 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 7. Fish and Wildlife Protection

(a) Purpose. New 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 and licensed after the effective date of this policy. This provision does not apply to added capacity at existing projects.

(b) Effect. This section imposes automatic operational limitations on a utility by reducing the amount of energy that can be scheduled over the Intertie, thereby increasing costs or reducing revenues for any utility owning or acquiring the output of a Protected Area hydroelectric resource.

(c) Implementation. Protected Area designations for stream reaches in the Columbia River Basin are shown in Exhibit C to this policy. Exhibit C uses Environmental Protection Agency stream reach codes. Subject to review and possible modification, BPA will consider the adoption of comprehensive state watershed management plans and a comprehensive protected area program developed by the Pacific Northwest Electric Power and Conservation Planning Council subsequent to implementation of this policy. BPA will also consider revisions to Protected Area designations if the Council's Program is amended.

(d) 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 Formula Allocation by either the nameplate rating of the project (in the case of ownership), or the amount of capacity acquired by contract.

(e) Exceptions

(1) PURPA Projects. BPA will entertain requests that it not enforce the provisions of section 7 in situations where an investor-owned utility has been compelled to acquire the output of a Protected Area hydroelectric resource under section 210 of the Public Utilities Regulatory Policies Act

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(PURPA). To qualify for this exception, the investor-owned utility must demonstrate:

(A) that it has exercised all opportunities available under federal and state laws and regulations to decline to acquire the output of the Protected Area resource in question;

(B) that it has petitioned its state regulatory authority(ies) to reduce the rate(s) established under PURPA for purchases from Protected Area resources in recognition of the increased costs or reduced revenues caused by operation of section 7(c) of this policy;

(C) that BPA was provided reasonable notice of all relevant regulatory and judicial proceedings to allow for timely intervention in such proceedings; and

(D) after taking all of the foregoing steps and exhausting all reasonable opportunities for judicial review, that it was compelled to acquire the output of a Protected Area hydroelectric resource by final order of FERC or a state regulatory authority issued under PURPA.

(2) Projects Contributing to Council's Fish and Wildlife Program or BPA Investments. Access will be automatically denied for projects developed in protected areas unless BPA receives sufficient demonstration that a particular project will provide benefits to existing or planned BPA fish and wildlife investments or the Council's Program. BPA's determination will be based on:

(A) information provided by the project developer, Federal and state fish and wildlife agencies, and tribes; or

(B) action by the Pacific Northwest Power Planning Council.

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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.

Section 8. Other Enforcement Provisions

(a) 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 deny access for a resource and refuse to accept schedules.

(b) Upon approval of the proposed U.S.-Canada Free Trade Agreement by the Canadian Parliament and the United States Congress, any and all distinctions made in this policy between Canadian and United States Extraregional Utilities shall terminate on the effective date of the Agreement.