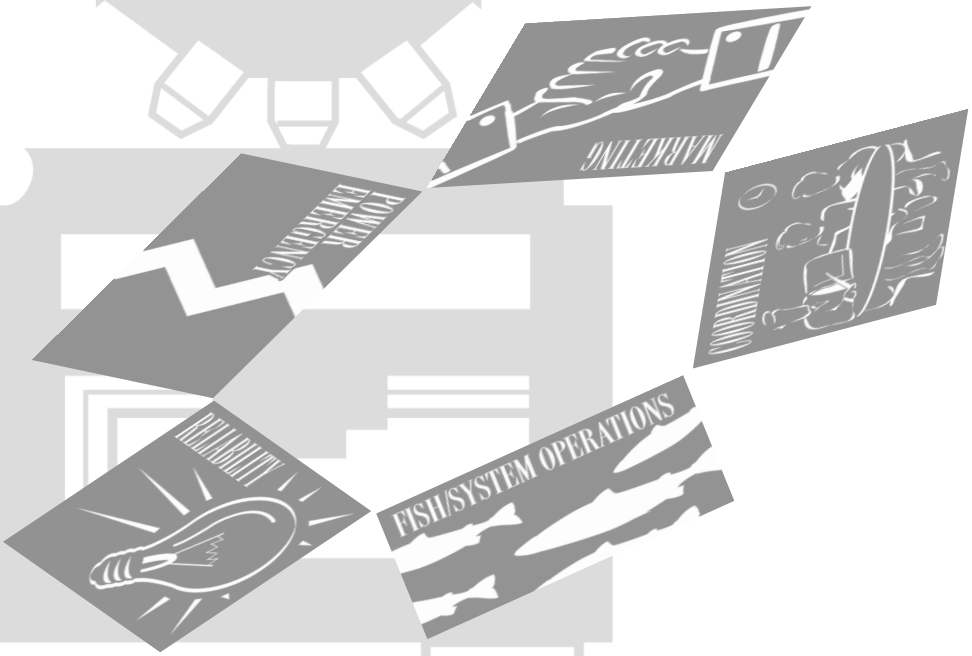
Endangered Species Act 2001 Progress Report for the Federal Columbia River Power System

Appendix B

In-Focus Supplement: 2001 Drought and Emergency Developments by Season



US Army Corps of Engineers
Northwestern Division

May 2002

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Introduction

This appendix is a detailed account of FY 2000–2001 events as they unfolded in the Federal Columbia River Power System (FCRPS). While hindsight is valuable for evaluating last year's decisions, actual operating decisions must be made in "real-time" — that is, at the very moment that events are occurring to influence those decisions. These decisions rely heavily on forecasts and modeling (i.e., modeled consequences of alternative actions), particularly runoff and market forecasts, reliability forecasts based on loss-of-load probability, projections of salmon emergence and migration timing, and other information that is constantly changing. This supplement presents the information available to decision-makers at the time critical decisions needed to be made, and subsequent actions taken.

FALL 2000 — October through November

Season	Runoff (MAF at the Dalles)	Prices ($ / Megawatt-hour)	Fish
Fall			
October 00		**October Forecast** November: $85 December: $90 January: $86	**October** Fall chinook spawning at Ives Island and Vernita Bar
November 00		**November Forecast** December: $85 January: $83 February: $70	**November** Chum spawning

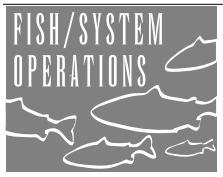
Maf: Million Acre-Feet EB: Early Bird FF: Final Forecast MM: Mid-Month

Seasonal Summary

- Precipitation was lower than normal in this period. However, since there is no strong correlation between fall precipitation and spring runoff, there was no indication chum operations would have greater than normal risk for refill or spring flows (beyond the usual risk inherent with chum).
- While river flow forecasts and river conditions for fish appeared within normal ranges, disturbing developments were occurring in the power market. By early November, wholesale power prices were starting to rise.
- As California's energy crisis deepened, BPA offered short-term assistance through a one-for-two power exchange with California utilities. Over a day, the immediate one-for-one energy return had no adverse effect on meeting Northwest load. The second megawatt (MW) then helped BPA meet load later in the month and reduced the need to make additional drafts of reservoirs. The additional return beyond delivered amounts was equivalent to the power a nuclear plant would generate in one week.
- A broad range of potential strategies seemed possible for meeting BiOp objectives.

Actions Taken

October 30, 2000



The Action Agencies began operating the FCRPS to provide flows below Bonneville Dam to help chum access mainstem spawning habitat. Operations supported a minimum flow of 125 kcfs, with a likely range of 125–130 kcfs. Operational challenges included establishing access to spawning areas at an elevation that could be maintained through egg incubation and emergence, typically in early April. Although the 2000 National Marine Fisheries Service (NMFS) BiOp expressed a priority for refilling reservoirs over flows for chum, refill risk was acceptable at this time.

November 14

To aid California during its ongoing energy crisis, BPA executed a series of one-for-two power exchanges. For every MW BPA delivered to California, California returned 1 MW within 24 hours and a second MW within the month.

November

Although the probability of power outages seemed low at the time, a task force under the leadership of three neutral utility/power organizations convened to develop a Winter 2000–2001 Energy Emergency Plan. Sponsors were the Pacific Northwest Utilities Conference Committee, the Northwest Power Pool and the Northwest Power Planning Council (NWPPC). Task force members included the Action Agencies, state representatives, and major utilities.

A fact-finding team was dispatched to California to assess its situation, and an Emergency Response Team (ERT) was established to ensure communications and coordination in the event of a power/transmission emergency. The task force also explored tools for dealing with an emergency, including increasing generation, maximizing imports (from Canada if none would be available from California), reducing loads, and maximizing transmission availability.

WINTER 2000–01 — December through February

Season	Runoff (MAF at the Dalles)	Prices ($ / Megawatt-hour)	Fish
Winter			
December 00		**December Forecast** January: $114 February: $114 January: $96	**December** Chum redds incubating below Bonneville Dam
January 01	EB: 79.5 FF: 80.4 MM: 71.8	**January Forecast** February: $212 March: $193 April: $186	**January** Fall chinook redds incubating at Ives Island and Vernita Bar
February 01	EB: 67 FF: 66 MM: 62.1	**March Forecast** March: $297 April: $316	

Maf: Million Acre-Feet EB: Early Bird FF: Final Forecast MM: Mid-Month

Seasonal Summary

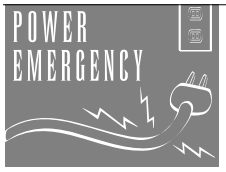
- The potential for below normal runoffs first became apparent. The new forecast for this period — the River Forecast Center's January "early-bird" forecast issued in late-December — indicated lower than average runoff for the January–July period, which meant there was potential for a low water year even with continued normal precipitation in 2001.
- As a result of California's continuing energy crisis, it was clear California utilities would have no power available to export to the Northwest over the fall and winter.
- The region's continuing energy crisis put increasing pressure on wholesale electricity prices, which peaked (on the spot market) in early December at more than 10 times the previous 4-year annual average. For example, from Jan. 16–20, 2001, BPA purchased approximately 1,000 aMW at a cost of over $50 million. During that time period, daily average market prices increased from $175/MWhr on Jan. 15 to $450/MWhr on Jan. 19. This created great financial concern within BPA.
- With a potential cold snap on the horizon, BPA pursued load reductions as a cost-effective alternative to market purchases.
- As BPA's range of options for meeting winter demand narrowed, it began to engage regional stakeholders in discussions on evolving conditions and choices. It was also forced to make choices about chum survival efforts vs. refill and a joint chum/power operation.
- Power emergencies were declared three times due to low water conditions and volatile market conditions.

Actions Taken

Early December 2000

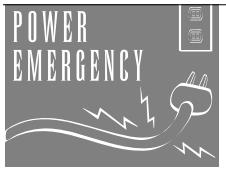
A projected cold snap with temperatures as much as 20 degrees colder than normal triggered a series of actions to ensure reliability of the strained Northwest power supply system. BPA sought to purchase as much power as needed for demand, with prices spiking to as high as $550 per MW.

December 8



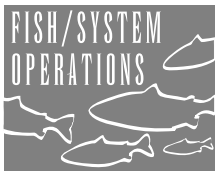
The ERT declared a pending power emergency for December 11 due to an anticipated drop in temperatures and called for immediate conservation measures. BPA declared a power emergency to position reservoirs for power production.

December 12



Moderate weather returned; the power emergency ended.

December

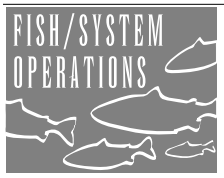


BPA closely worked with NMFS, Fish and Wildlife Service (FWS), and other federal agencies to keep them apprised of the power situation. The Action Agencies managed flows to have the least impact on fish, especially chum, below Bonneville Dam. Because increased power production would likely raise flows below Bonneville Dam to above 140 kcfs, BPA deferred flows during the day until nighttime, which discouraged fish from spawning at elevations that might dry out later in the winter.

January 5, 2001

BPA joined the governors of Washington and Oregon to call upon the public to reduce electricity consumption by 10 percent, and began to work with utilities to initiate a new Demand Management program. BPA sponsored ads in 17 regional newspapers informing the public of measures they could take to conserve electricity.

January 10



By early January, chum spawning was complete. The Technical Management Team (TMT) of the NMFS's Regional Forum recommended a tailwater of 11.7 feet to protect 90 percent of redds during incubation. The NMFS BiOp recognizes there will always be a trade-off between fall chum operations and meeting spring refill targets; however, the BiOp favors refill. Despite worsening drought conditions, the Action Agencies were able to determine an operation for mutual benefit of chum and power by providing above minimum flows.

January 17

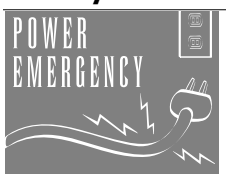
BPA was faced with a 1,000-MW deficit for the next or subsequent week. Regional Federal Executives were consulted and concurred with BPA's decision to spend up to $10 million per day, or $50 million for the week, to purchase power. If those amounts were exceeded, BPA would declare an emergency.

Meanwhile, the final January forecast came in at 80.4 MAF (76 percent of average).

January 17

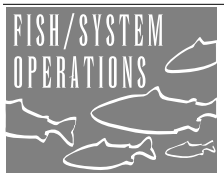
BPA spent over $10 million on purchased power for the day.

January 18



BPA expenditures exceeded $10 million for the day again, and the agency calculated its weekly purchases to meet load would exceed $50 million. BPA declared a power system emergency.

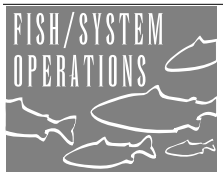
January 19



At the weekly Regional Federal Executive meeting, BPA shared additional information about the emergency. Regional Executives generally supported drafting FCRPS reservoirs to meet load (after acquisition of reasonably priced power), with maximum 160 kcfs flows below Bonneville Dam and with limitations on ramping rates to avoid stranding chum salmon below the dam. At subsequent weekly meetings, the Regional Executives continued to discuss and consider responses to the power conditions.

Also on January 19, at an emergency meeting of the TMT, BPA discussed that Bonneville outflows were likely to continue exceeding that needed to meet the 11.7-foot tailwater elevation, in order to increase energy supply.

January 21



To reduce draft at Grand Coulee, outflows from Dworshak and Libby would be increased early this week.

January 25

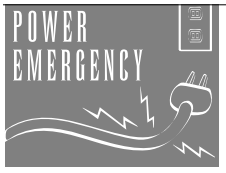
California was continuing to experience Stage 2 and 3 power emergencies. BPA Acting Administrator Steve Wright mailed a letter to the region describing recent developments with high power prices and the uncertainty caused by market volatility. He outlined BPA's concerns about draining cash reserves and maintaining cash flows, and warned of potential rate increases if the region did not act to reduce loads and conserve energy. He invited comments on how to minimize potential rate increases.

January–February

During this time BPA took the following actions to reduce loads either for the near term, as needed to reduce loads to better manage the output of the power system, or in the long term, to decrease BPA's exposure to a high-priced and volatile market:

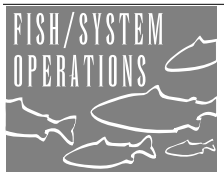
- Began negotiating load reductions for the remainder of FY 2001 from several Direct Service Industry (DSI) customers, resulting in savings of 543 average megawatts (aMWs) at a cost of $498 million. In addition, BPA purchased 215 aMW from DSIs that had remarketing rights for their federal power at a cost of $364 million. By purchasing this power, BPA was able to keep that energy in its inventory.
- Began to develop initial strategies for purchasing reductions in irrigation pumping loads and in water use from Banks Lake and the Snake River for the summer of 2001.
- Signed up 12 customers for the Demand Exchange program that enables load reductions from end-use consumers on an hourly basis.
- Accelerated implementation for FY 2002 of the Conservation Augmentation (ConAug) program established to include conservation purchases in BPA's augmentation portfolio and accelerated implementation of a Conservation and Renewables Discount (C&R Discount).

February 5



The power emergency ended.

Early February

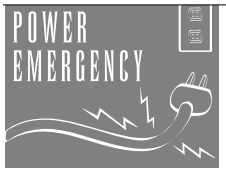


The February Early Bird forecast dropped significantly to 67.0 MAF (63 percent of average). In discussions with the TMT, BPA indicated it would have only an estimated 44 percent probability of making its annual payment to the U.S. Treasury in September if the hydrosystem were managed to the BiOp targets for spill and flow. BPA began to discuss contingency hydro operations with TMT, Implementation Team (IT), and Regional Federal Executives to maintain the integrity of the 2000 BiOps, while preserving BPA's ability to repay Treasury and maintain system reliability.

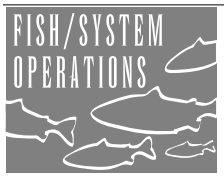
February 7–8

At TMT and IT meetings, BPA presented "Power and Operations Outlook 2001," a document sharing BPA's reliability and financial conditions. Also included was a set of proposed contingency operations and priorities for some project operations over others. BPA requested that TMT provide guidance about what biological objectives ought to be in a year with very low water and very high power prices. Discussions also covered whether chum operations should continue, risking the April refill targets needed for spring flow augmentation and June refill.

February 12



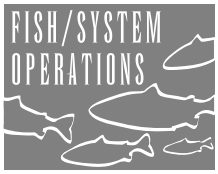
After extensive consultation with other federal agencies, BPA declared a power emergency on Feb. 12 to meet increased power demand brought on by below normal temperatures throughout the Northwest.



Releases were increased at Dworshak (from 1.3 to 5 kcfs), Libby (from 15 to 20 kcfs), and Hungry Horse (from 5 to 6 kcfs) reservoirs. This avoided drafting Lake Roosevelt behind Grand Coulee more than 1.5 feet per day and below 1,225 feet through March. The 1,225-foot elevation at Grand Coulee is critical for meeting a variety of purposes: maintaining the Inchelium Ferry; protecting Vernita Bar redds, which require a minimum flow of 65 kcfs; and providing the operational flexibility needed to maintain reliability of BPA's transmission system. An agreement was negotiated with Canada for additional releases.

BPA continued to make "reasonably priced" purchases in the market, spending $900,000 to purchase 120 MW on February 12 alone.

February 21



Throughout February, Action Agency staff continued intense discussions on contingency operations and criteria for making operational decisions. At the February 21 TMT meeting, BPA shared updated information and analyses, including a revised set of preliminary criteria for declaring a power emergency:

- Power system reliability due to insufficiency of power supply; and
- Power system reliability due to insufficient funds to acquire sufficient electrical generation and maintain other BPA-funded activities, including those for fish and wildlife. These criteria would be triggered by a specific threshold (to be determined) of probability of negative cash reserves.

The federal agencies also presented proposed operational priorities consistent with the measures in the NMFS and FWS BiOps, including:

- Maintaining power/chum flows through emergence or April 10, whichever came first;
- Providing full fish transportation in the Snake River as planned under the BiOps and from McNary in the spring;
- Conducting spring spill operations at FCRPS projects;
- Balancing summer flow augmentation and spring spill operations, with Dworshak refill being the highest priority, and ensuring sufficient water at Hungry Horse and Libby to meet bull trout minimum flows;
- Conducting summer spill operations at FCRPS projects;
- Ensuring Vernita Bar flows;
- Augmenting spring flows, with an emphasis on May; and
- Monitoring water quality impacts.

BPA indicated its intent to seek input from TMT and IT and finalize criteria by early March. The state of Washington suggested that BPA consider mitigating potential impacts on fish, and BPA agreed.

February 22

BPA issued a solicitation for up to 1,000 MWs of wind projects as part of its long-term strategy to acquire generation, conservation, and take other steps to reduce a 3,000 average megawatt (aMW) power deficit in FY 2002–2006. BPA was already considering previously received unsolicited proposals to acquire 42 aMW from five additional wind projects in Oregon, Washington, and Montana. The February solicitation resulted in 25 proposals for 2,612 MW of new wind power. After evaluating the proposals, BPA selected seven projects totaling 830 MW for further consideration.

SPRING 2001 — March through June

Season	Runoff (MAF at the Dalles)	Prices ($ / Megawatt-hour)	Fish
Spring			
March 01	EB: 58.6 **FF: 58.6** MM: 57.6	**March Forecast** March: $272 April: $266 May: $261	**March** Non-listed Spring Creek Hatchery releases
April 01	EB: 55.7 FF: 56.1 MM: 57.7	**April Forecast** May: $300 June: $363 July: $390	**April** Chum emergence; fall chinook emergence at Vernita Bar
May 01	EB: 57.2 FF: 56.2 MM: 56.6	**May Forecast** June: $275 July: $315	**May** Steelhead migrting in Snake and Columbia

Maf: Million Acre-Feet EB: Early Bird FF: Final Forecast MM: Mid-Month

Seasonal Summary

- The March early-bird forecast continued to indicate deteriorating runoff conditions. As a result, BPA declared a power emergency on April 3 and was unable to begin spring spill. Additionally, April refill targets specified by the BiOps could not be attained.
- Several times during this period, California experienced Stage 2 and 3 power emergencies, with a few rolling blackouts.
- Extensive reliability analyses determined the financial consequences of full, limited, and no spill options, showing that full spill (i.e., spill to levels specified in the NMFS BiOp) could not be an option.
- By late April, runoff forecasts improved slightly. Combined with new generation and load reductions, and the potential for a Grant PUD contingency spill swap, sufficiently improved system reliability calculations allowed for a limited spring spill to begin in mid-May. Targeted to the peak of migration, which was later than average, the spill continued through mid-June.
- The Corps of Engineers transported fish on the Snake River consistent with the BiOps.
- The Action Agencies participated in intense regional coordination efforts to develop financial and reliability principles and emergency criteria as part of the 2001 Operations Plan.

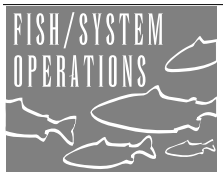
Actions Taken

March 5, 2001

The federal agencies released the draft set of proposed principles describing the circumstances for declaring a power emergency, as well as actions that must be taken prior to declaring an emergency. This document was posted on the **www.salmonrecovery.gov** web site for public comment through March 15.

March 7

At an IT meeting, federal agencies continued discussions on key operational issues. BPA also provided a detailed description of proposed contingency operations and studies, including a description of the concept of flexible storage, where any volume over and above what is needed for load would be stored and made available for various fish operations if a power emergency was no longer in place. Recognizing the importance of the Spring Creek Hatchery fish to tribal fisheries, BPA agreed to a March 1 request to provide a limited and targeted spill for these fish, providing 200 MW per hour for 12 hours for three nights, at a cost of $2.1 million.

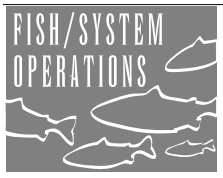


As maintaining the tailwater elevation at Bonneville Dam put pressure on Grand Coulee elevations, the federal agencies, states, and tribes discussed continuing monitoring of chum emergence. A target date of March 7 had been set for 90 percent chum emergence, but it was not until March 16 that 50 percent of the chum emerged and chum operations ceased.

March 8

The federal agencies continued discussions about regional reliability, fish operations, and BPA's financial situation with key regional partners at a NWPPC meeting. (Regional federal, state, and tribal executives subsequently met March 16, March 30, and April 6 to continue discussions. TMT met on March 12, 14, and 21, and developed a matrix of operating recommendations from various members including Washington, Montana, Idaho, and Columbia River Inter-Tribal Fish Commission (CRITFC).)

March 21

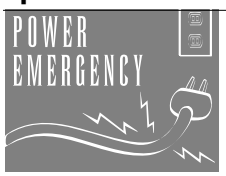


Emergence of non-listed Hanford Reach fall chinook began earlier than expected. Monitoring of the sites continued and requests were made from regional salmon managers at TMT to maintain Vernita Bar minimum flows of 65 kcfs.

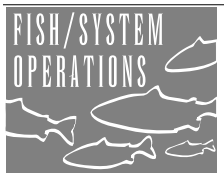
March 29

BPA Acting Administrator Steve Wright sent another letter to the region describing reliability and financial conditions, and the intended approach to deal with hydrosystem operations through the proposed principles and criteria. (Ten days prior, California began experiencing Stage 2 and 3 power emergencies, with rolling blackouts.)

April 3



The April early-bird forecast came in at 55.7 MAF, another decrease. BPA declared a power emergency and announced it would be unable to support spring spill because of impacts to system reliability.



Federal, state, and tribal representatives discussed options for risk management strategies to assist migrating juveniles. In low flow years, the NMFS BiOp recommends maximum transportation at the Snake River projects. Accordingly, transportation had already begun at Lower Granite on March 25 and Lower Monumental and Little Goose on April 1.

April 9

BPA held a press conference to announce that the region's electricity consumers had difficult choices ahead: reduce the amount of load placed on BPA, or BPA rates could increase as much as 250 percent. The immediate solution would be to reduce as much load as possible so BPA would not have to purchase large amounts of power in the volatile market. The long-term solution would be to bring on new generation and improve infrastructure. BPA joined the Northwest governors in challenging each customer class to reduce its loads by 10 percent. While some had suggested that BPA defer its payment to the U.S. Treasury in order to provide spill for fish, BPA and many others preferred to leave this option as a last resort because of political risks.

Power Emergency Criteria

In early March 2001, the federal agencies released draft criteria for declaring power system emergencies. These power and financial reliability criteria were designed to allow for objective decision-making relative to the specific drought and extreme power market conditions of last year. After consideration of a wide range of comments from regional stakeholders, the criteria were finalized in April as described below.

1. **Reliability requires sufficient resources to meet near-term system demand.**
   The near-term insufficiency determination was based on volume forecasts — 54 MAF was the threshold below which BPA could not meet spring and summer power system demands without drafting reservoirs and affecting system reliability. In the May and June projections, a forecast buffer was used to assure that the final forecast would have no greater than a 25 percent probability of coming in under the 54 MAF limit. That buffer was 4.5 MAF in May and 3.5 MAF in June. That meant that the system was determined to be insufficient in the short term with volume predictions of less than 58.5 MAF in May and less than 57.5 MAF in June.
2. **Reliability requires sufficient resources to maintain no greater than a 5 percent loss-of-load probability in any of the next 12 months, the region's historic standard.**
   When the situation was being evaluated in May, a NWPPC report showed the region had a 26 percent chance of not meeting demand in the December 2001–January 2002 period. Analysis indicated that Federal system storage needed to be increased by 1,500 MW-mos to reduce this probability to 20 percent.
3. **Reliability requires sufficient cash reserves, which was defined as BPA having no greater than a 20 percent probability of having zero cash reserves in any of the next 12 months.**
   With sufficient cash reserves, BPA could consider funding actions to offset any negative effects of emergency power operations or buy extra-regional power to reduce the amount of storage needed for system reliability the following winter.

Emergency Options Considered but Not Exercised

1. Alternative Sources of Funds

1A. Deferral of Treasury payment

BPA considered but chose not to risk deferring its U.S. Treasury payment for two reasons:

- To maintain power reliability, BPA must acquire power on the market to meet load. BPA's ability to acquire power on the market depends upon having sufficient financial resources. A deferral or even anticipated deferral of a Treasury payment would have cast doubt upon BPA's financial credibility and ability to make timely payments.
- Making planned annual Treasury payments is important to maintaining the benefits of the FCRPS in the region. The statutes applying to rates for BPA power provide that BPA make "requirements" sales to its Pacific Northwest customers at cost-based rates, not market prices. If BPA misses a Treasury payment, interests from outside the region would likely press to alter the statutes applicable to BPA, which could result in significantly higher costs for electrical power.

1B. Use of $250 million short-term treasury note

BPA has access to a one-time $250 million short-term Treasury note. If BPA uses the note, it cannot use it again. The same considerations apply to use of this note that apply to missing a Treasury payment. The financial reliability criterion developed for 2001 is measured on cash reserves rather than BPA's cash balance so as not to expose the power system emergency criteria to the swings associated with the timing of capital spending and borrowing.

1C. Rate adjustments

BPA did not raise rates during FY2001 (Oct. 2000–Sept. 2001) because:

- At the time of the emergency conditions, the 1996 Wholesale Power Rates were still in effect. These were essentially fixed rates with no Cost Recovery Adjustment Clauses CRACs) or other mechanisms to expeditiously change rates. It would have been a practical impossibility to conduct a section 7(i) process in the time available to respond. Even if that hurdle could have been surmounted, a rate increase would not have achieved the desired results because the change would have gone into effect during the time when BPA's receipts are fully obligated to payment on the Energy Northwest debt.
- During much of the period that BPA engaged in emergency operations, the problem was availability of power at any price. In these situations, a rate increase would simply have increased the dollars chasing power that was not available.
- During a less than robust economy, an abrupt rate increase would not necessarily have resulted in an increase in revenues.

In September 2000, BPA was beginning a supplemental proceeding related to the WP-02 rate proceeding (2002 Wholesale Power Rates). The proceeding's purpose was to develop a risk mitigation package allowing BPA to respond appropriately to load variability and volatile market prices. The proceeding resulted in a three-tiered CRAC, including a load-based CRAC (LB CRAC), a financial-based CRAC (FB CRAC), and a safety net CRAC (SN CRAC). The WP-02 proceeding established rates for implementation in October 2001. Due largely to application of the LB CRAC, the resulting rates were 45 percent higher than the comparable rate for the previous rate period (1996–2001). The CRACs improve BPA's ability to adjust rates in response to changes in loads and prices. However, these tools were not available in 2001–2002.

1D. Arrange to buy power in FY 2001 but pay in FY 2002

A power supplier would make this arrangement only if the supplier had confidence in the solvency of the purchaser. Delay of payment does not remove the obligation to pay. In addition, a power supplier would have charged additional cost for delaying payment, so the overall cost would be higher. BPA's power reliability difficulties extended into the fall and winter of FY 2002 as well. Consequently, this type of arrangement would not remove BPA's financial power reliability risk in FY 2002.

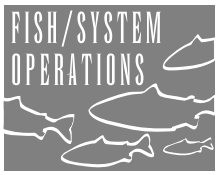
1E. Transmission surcharge to help the PBL meet its financial obligations

A surcharge would likely take months to impose. In addition, FERC orders call for a utility to keep its power and transmission functions separate.

2. Further Adjustments to the Physical Power Reliability and Financial Power Reliability Financial Criteria to Take Increased Risk to Reliability

BPA declined to implement certain adjustments that would have unreasonably risked physical and financial power reliability. Like the reasons for not deferring a Treasury payment, excessive risk of failure to meet load due to the lack of financial resources to acquire needed power would have undermined BPA's ability to actually acquire needed power.

April 13



The Regional Federal Executives met again with their state and tribal counterparts, and released the draft "2001 FCRPS Operations Plan" on the **www.salmonrecovery.gov** web site for public comments through April 20. Based on input from TMT, IT, and other state and tribal representatives, the draft plan included financial and reliability principles; proposed criteria and processes for declaring a power emergency (see following box); biological analyses indicating survival of listed fish at various spill levels; and proposed spring and summer contingency operations. The biological analyses indicated that without spill, system survival could decrease 1 to 15 percent, depending on the stock and proportion of the run transported.

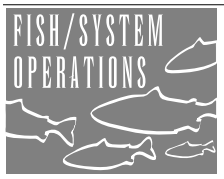
April 27

Operations plan comments were summarized and presented back to regional federal, state and tribal executives. A revised operations plan was released on May 11 for additional public comment. The federal agencies finalized the plan on May 25 (see box on previous page).

Early to Mid–May

The May early-bird forecast surprised the region when it increased slightly to 56.5 MAF. Also, in mid-May, analyses by the NWPPC indicated the reliability picture was beginning to improve due to some new generation and load reductions. However, California continued to experience power insufficiencies and rolling blackouts in early May. On May 18, the Columbia Generating Station went down for repairs, removing nearly 1,000 MW from BPA's system.

May 16



A limited spring spill began at Bonneville and The Dalles dams. Juvenile chinook and steelhead were beginning to migrate through the hydrosystem, and biological indicators suggested a targeted spill would provide the greatest benefits in the immediate next few weeks. Because the reliability picture seemed improved and BPA had arranged a contingency plan with Grant PUD (see following box), BPA agreed to a limited spill of 300 MW-mos. Targeted at The Dalles and Bonneville as recommended by regional fish managers, this spill was expected to provide the greatest survival benefits because it helped fish coming from both the Snake and Columbia rivers.

At the same time, to mitigate the impacts of limited spring spill, BPA announced a solicitation for projects that would increase fish survival this season. Projects needed to address fish impacted by the power emergency and could cover actions in four categories: actions to increase tributary flows, tributary habitat passage improvements, tributary diversion screening, and fish stock relocation and outplanting. Projects would follow the NWPPC process and include independent scientific review.

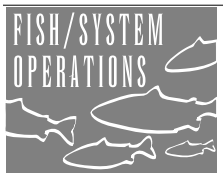
Grant County PUD Contingency Energy Swap

In mid-May, BPA negotiated an agreement with Grant County PUD that provided a back-up plan for power reliability if BPA continued a limited amount of spill for spring migrants and water conditions deteriorated. Under the proposed arrangement, which was subject to FERC approval, Grant County PUD would have foregone a portion of its spill on the mid-Columbia in the late spring or summer and delivered the energy to BPA. This would have allowed BPA to replace power lost by the May spill — a creative contingency plan allowing for spring spill without reducing BPA's ability to meet loads. Ultimately, however, this option was not exercised.

May 17

In its continuing efforts to aggressively negotiate load reduction, BPA announced a short-term policy to encourage the use of small electric generation to help the Northwest meet its power needs.

May 19

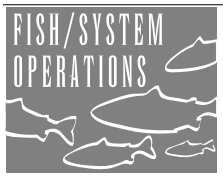


An emergency spill is conducted to protect juvenile fish released in the Ice Harbor Dam forebay. About 359,000 juvenile salmon and steelhead were released after overflow screens plugged on a fish barge. A spill of 40 kcfs for 6 hours is authorized to safely pass the fish.

May 25

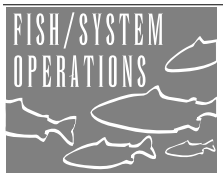
With indications of improving reliability and reservoir refill conditions, the Action Agencies initiated additional limited spill at John Day and McNary dams.

June 1



The federal agencies agreed to extend spill for another week after the June early-bird forecast came in at 56.1 MAF. According to the reliability criteria in the 2001 Operations Plan, 53.3 MAF was needed to meet loads, with an approximate error buffer of 1.5–4.0 MAF. Although close to the edge of the reliability threshold, BPA agreed to accept the risk.

June 8



BPA and other federal agencies decided to continue the limited spill operations until a total of 600 MW-mos had occurred. TMT was asked to develop a plan for optimizing the biological effectiveness of the remaining spill. TMT recommended that spill end first at McNary, then John Day and last at Bonneville and The Dalles. Spill continued until June 14 at McNary, and until June 15 at the other projects.

SUMMER 2001 — June through August

Season	Runoff (MAF at the Dalles)	Prices ($ / Megawatt-hour)	Fish
Summer			
June 01	EB: 56.1 FF: 55.5 MM: 55.9	**June Forecast** July: $197 August: $237 September: $174	**June** Sturgeon spawning
July 01	EB: 53.9 FF: 54.7	**July Forecast** August: $83 September: $77	**July–August** Fall chinook migrating; other non-listed fish throughout Columbia Basin
August 01		**August Forecast** September: $46	**August** Bull trout in mainstem

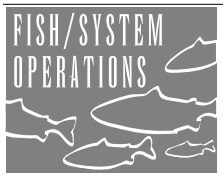
Maf: Million Acre-Feet EB: Early Bird FF: Final Forecast MM: Mid-Month

Seasonal Summary

- The power emergency declared on April 3 continued through the summer. It concluded Oct. 1.
- As of mid-June, the new runoff forecast had the system close to the level at which no further spill could be provided without violating the power and financial reliability criteria, despite reductions in BPA load due to buy-downs and conservation measures. However, the Federal Energy Regulatory Commission's (FERC) later decision to impose price caps on wholesale power had an offsetting effect, dropping the market price forecast significantly and allowing discussions of a summer spill operation to resume later in the summer.
- NMFS biological analyses demonstrated that minimal benefits would be derived from summer spill in low flow years when most Snake River fish are transported. This contributed to the decision to target spill on Columbia River stocks that were transported to a lesser degree. Meanwhile, transportation was continued at Lower Granite, Lower Monumental, Little Goose, and McNary dams on the Snake River through Oct. 31.
- During this period, the federal agencies solicited comments about potential actions to aid non-listed fish, recognizing the importance of non-ESA listed fish to the region. Additionally, BPA agreed to fund several projects providing immediate benefits to affected fish.
- Given decreasing wholesale power prices, improved reservoir conditions, and a slightly higher runoff forecast in July, the Action Agencies agreed to begin a limited summer spill as requested by the CRITFC. When actual runoff volumes were found to be higher, the spill was increased and continued until Aug. 31.
- Due to severe drought conditions, the volatile wholesale power market, and the overarching need to accommodate the multiple purposes of the FCRPS, actual spill for the fiscal year was roughly 20 percent of that called for in the NMFS 2000 BiOp.

Actions Taken

June 15, 2001



The federal agencies began to discuss summer spill options at a June 15 Regional Executives meeting. Discussions included updated analyses regarding reliability and financial conditions. NMFS biological analyses indicated that though summer spill positively benefited Snake River fall chinook migrating in-river, the impact on overall system survival was negligible because the majority of these fish would be transported. (Spring and summer transport operations, which continued through Oct. 31, eventually collected nearly 90 percent of the runs.) Also, the expected mortality of Snake River migrants in the Lower Granite pool was extremely high (80 percent) before any spill benefits were available. A NWPPC analysis suggested that survival of non-ESA listed Hanford Reach stocks would be enhanced by only 1.3 percent with spill.

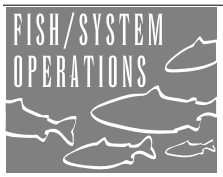
June

Federal executives asked the region to help explore other alternatives that would have comparable or better biological benefit if no summer spill or a modified amount was available. The federal agencies accepted input to this question, along with comments on the updated analyses, until June 22. The federal agencies also accepted comments about potential actions to aid non-listed fish.

Comments received on the summer spill questions reflected a wide range of views and concerns among regional parties. Some felt conserving energy should be a top priority and did not support spill for negligible benefits to fish survival. Others felt that providing full summer spill should be the priority and BPA should purchase power in the market regardless of cost and/or should defer its Treasury payment to allow for full spill.

June 29

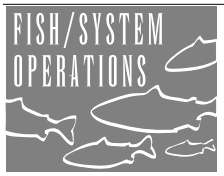
Regional Executives met again to discuss all information and input received. The day prior, federal agencies decided against any summer spill after receiving the July early-bird forecast of 53.9 MAF — well below the 55.6 MAF threshold established for reliability. At the same time, BPA's Columbia Generating Station overran its scheduled maintenance and refueling outage by 2 weeks, removing nearly 1,000 MW of generation.



The federal agencies did, however, agree to fund several projects designed to mitigate the impacts of no spill by providing immediate benefits to affected fish. BPA agreed to fund additional predator control by increasing the bounties to catch pikeminnow. BPA and the Corps agreed to expedite needed improvements to the water supply at the Dworshak National Fish Hatchery to benefit Snake River fall chinook. The federal agencies also agreed to monitor market, stream flow, and federal system conditions to assess options later in the summer.

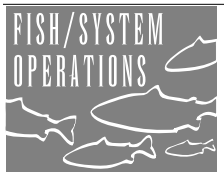
On June 29, BPA announced its power customers had committed to reducing loads by a total of 2,115 aMW for the 2002 fiscal year. Customers had a wide array of possible tools for reducing their BPA purchases, including end-use customer load reductions, separate market purchases, and energy efficiency measures. Conservation by utility customers who purchased load-following products from BPA played a particularly important role in obtaining these load reductions. Other utility companies agreed to sell or give back 10 percent of their BPA energy for 1 year. Five investor-owned utilities (IOUs) agreed to sell back 10 percent of their power sales contracts for fiscal year 2002, and two IOUs agreed to sell subscription contracts back for fiscal years 2002–2006.

July 2



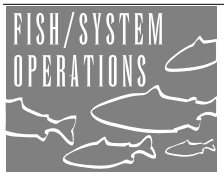
Increased flows were provided from Hungry Horse to smooth the natural flow recession and avoid adverse impacts on bull trout. Also, at the request of salmon managers, the Corps increased water releases from Dworshak Dam in order to improve water quality downstream. Discharge from the cold, deep reservoir reached 10 kcfs on July 8.

July 17



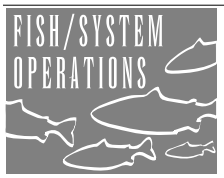
The CRITFC submitted a System Operation Request (SOR) for summer spill at the four federal projects on the mainstem lower Columbia River. Specifically, CRITFC asked BPA to purchase power on the market to replace generation lost by providing fish passage spill.

July 24



Given a slightly higher final July forecast of 54.7 MAF (52 percent) and decreasing market prices, the Action Agencies began a limited summer spill operation. Although less than requested, in CRITFC's SOR it consisted of 45 kcfs flows for 5 hours per day at Bonneville and 30 percent of river flow for 24 hours per day at The Dalles. This approach did not require an overall increase in river flow, only a re-allocation of some flows over spillways, and so did not reduce the system's reliability storage.

August 8



At a TMT meeting, the federal agencies decided to increase the limited summer spill due to higher actual volume runoff (58.2 MAF, 3.5 MAF higher than the final July forecast) and BPA power purchases that had further improved reservoir storage. Spill was increased to 50 kcfs for 24 hours per day at Bonneville and to 40 percent of river flow for 24 hours per day at The Dalles. Total summer spill was 395 MW-mos.