KARIN IMMERGUT, OSB #96314
United States Attorney
STEVE ODELL, OSB #90353
Assistant United States Attorney
District of Oregon
600 United States Courthouse
1000 SW. Third Avenue
Portland, OR 97204-2902
(503) 727-1000

KELLY A. JOHNSON
Acting Assistant Attorney General
SETH M. BARSKY
Assistant Section Chief
RUTH ANN LOWERY
Trial Attorney
Wildlife & Marine Resources Section
Benjamin Franklin Station, P.O. Box 7369
Washington, DC 20044-7369
(202) 305-0217 (ph)
(202) 305-0275 ((fax)

FRED R. DISHEROON
Special Litigation Counsel
U.S. Department of Justice
Environment & Natural Resources Division
Benjamin Franklin Station, P.O. Box 7397
Washington, DC 20044-7397
(202) 616-9649 (ph)
(202) 616-9667 (fax)
Attorneys for Defendant

UNITED STATES DISTRICT COURT
DISTRICT OF OREGON

NATIONAL WILDLIFE FED'N, et al., Plaintiffs, v. NATIONAL MARINE FISHERIES SERVICE and UNITED STATES ARMY CORPS OF ENGINEERS, Defendants.	)	Civ No. 01-00640-RE Declaration of Roger Schiewe

I, Roger Schiewe, declare as follows.

1. I am currently the Fishery Impact Technical Expert and Principal Hydro Power System Operations Engineer for the Bonneville Power Administration (BPA). I help with the planning and analysis of the Federal Columbia River Power System (FCRPS) impacts from operations for fish and other non-power purposes. I have worked continuously for BPA in different aspects of the FCRPS operation and planning function since July 1970. BPA uses the results from computer models designed to simulate the physical characteristics and operations of the hydroelectric system dams and reservoirs in the Columbia River Basin in making decisions in many areas. Some examples are: Endangered Species Act consultations with National Oceanic and Atmospheric Administration – National Marine Fisheries Service (NMFS) and the United States Fish and Wildlife Service (USFWS); BPA rate-making processes; Columbia River Treaty and Pacific Northwest Coordination Agreement planning activities; as well as short and long term power marketing decisions.

2. I am currently involved in the system modeling required to propose BPA rates for the next Rate period (FY2007-2009), analysis of the potential for construction and operation of a new reservoir in the Yakima River Basin (Black Rock), and analysis of the Columbia River Initiative proposed by the State of Washington.

3. I received a Bachelor of Science degree in Mathematics from the University of Oregon in June 1970 and subsequently furthered my education at Portland State University through engineering courses. In July 1977, I passed the Engineer-in-Training examination and received certification from the Oregon State Board of Engineering Examiners as an Engineer-in-Training. That certification allowed me to become rated as an Engineer with the Bonneville Power Administration.

4. I coordinated the analyses (Study) undertaken by BPA wherein BPA analyzed the effects of operating portions of the FCRPS dams to provide objectives requested by the Plaintiffs, National Wildlife Federation et. al., in their motion for preliminary injunction, or in the alternative a permanent injunction, against the U.S. Army Corps of Engineers (COE), the U.S. Bureau of Reclamation (BOR), and NMFS. The objective of the Study was to identify the potential costs to ratepayers, and other power-related concerns that would be expected to occur if the preliminary or permanent injunction were granted as compared with the operations conducted under the Updated Proposed Action (UPA) reviewed in o the 2004 Biological Opinion (2004 BiOP).

5. Specifically, NWF asked the federal Defendants to do four things:

a) To decrease (i.e. speed up) by at least 10% the water particle travel time in the Snake River (from the head of Lower Granite reservoir to Ice harbor) between June 20, 2005 and August 31, 2005 - with the decrease distributed evenly during this period, over and above what the water particle travel time would be under the 2004 BiOp Updated Proposed Action;

b) A similar reduction of travel time (10 % or greater), in the Columbia River (from its confluence with the Snake River to Bonneville dam) between July 1, 2005 and August 31, 2005;

c) To provide spill, (a) from June 20, 2005 through August 31, 2005, of all water in excess of that required for station service, on a 24-hour basis, at each of the four lower Snake River projects; and, (b) from July 1, 2005 through August 31, 2005, of all flows above 50,000 cfs, on a 24-hour basis, at McNary Dam; and

d) To comply with and implement, except to the extent superseded by the provisions of requested relief above, all of the measures of the RPA in the 2000 FCRPS BiOp. See Plaintiffs' motion for a preliminary or permanent injunction.

6. In order to evaluate the effects of the first two requests, related to water particle travel time (WPTT), I needed to know how much additional flow or, alternatively, how much drawdown of forebays in the lower Snake and lower Columbia rivers would meet the objective of reducing WPTT ten percent. Plaintiffs provided the

underlying assumption concerning the amount of flow in the base case – that is the amount of water that would need to be "accelerated" in the Snake and Columbia Rivers during the pertinent time periods, was provided by Plaintiffs in their motion for injunctive relief. The base flows were assumed to be 27,750 cubic feet per second (cfs) in the Snake River, and 137,250 cfs in the Columbia River. See page 3 of Plaintiffs' Motion. [1] I confirmed that the Plaintiffs' flow assumptions were very similar to our own and then provided the base flow information to Dr. James J. Anderson of the University of Washington Columbia Basin Research, School of Aquatic and Fishery Science, who has computer models to compute WPTT and who has an established consultative contract with BPA. I asked him to calculate the amounts of increased flow and drawdown information to achieve a ten percent reduction in WPTT.. He agreed with plaintiffs' supposition that a 10% decrease in WPTT could be attained by either lowering the level of the water behind the dams (called forebay drawdown) thereby reducing the cross-sectional area of the river behind the dams, or by increasing the total volume of flow within the rivers, or by combinations of these two methods. See Pettit Declaration Para. 18.

7. Since this type of analysis is time intensive and there was only enough time to analyze one scenario before our response to Plaintiffs' motion was due, I determined the most practical solution to decrease WPTT would be to increase the total volume of flow in the river by drafting stored water from various FCRPS storage reservoirs. Even this approach would cause significant impacts to recreation, resident fish and cultural resources. Even with these significant impacts, flow augmentation

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[1] As Plaintiffs' Declarant, Steve Pettit notes in his declaration, there are, essentially, two variables, cross-sectional volume, and amount of flow, one could manipulate in the FCRPS to alter WPTT.

seemed less onerous than the forebay drawdown approach, or other options to meet the 10 percent reduction in WPTT.

8. My rationale was that the forebay drawdown approach presented significant impacts to more river users (including recreation, barge traffic, commercial port operations, cultural resources, irrigation and anadromous fish facilities) and such impacts would be difficult (if not impossible) to address between the time the Court would decide to issue an injunction and the time the operation for the summer of 2005 would commence. See, e.g. declarations of Dave Ponganis and Cynthia Henriksen. Since the Corps of Engineers and the Bureau of Reclamation have direct control over the FCRPS reservoirs (i.e. they would not need permission from multiple third parties), the certainty of being able to implement the requested relief was much higher. Using FCRPS storage projects would also eliminate the complex, time-consuming process of negotiating for additional water from other providers (which likely is not even available in a drought year like 2005). For example, some suggest using water from Canadian storage (Pettit Declaration Para. 56). In the past, BPA has obtained commercial agreements with BC Hydro allowing for negotiation of seasonal use of non-Treaty storage when mutually agreeable. An indication of the difficulty in establishing such an agreement on short notice is that the last such agreement expired in June of 2004 - and the parties have been unable to reach accord on a new commercial agreement since then. Moreover, relying upon FCRPS projects would almost certainly result in a more cost-effective alternative.[2] BPA has a statutory obligation, established in section 9 of the 1974 Federal Columbia River Transmission Act, 16 U.S.C. 833g, to make decisions that

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[2] It is clear from past experience, that any owner/operator of large reservoirs would incur risks from altering their planned operation, and would expect compensation to modify their current water management operations.

provide electric power at the lowest possible rates. Finally, I felt this approach would lead to reliable results based upon my familiarity with the models and methodology used to evaluate flow augmentation from these same FCRPS storage projects.

9. There were several other criteria that formed the basis of our analysis. One was that it was assumed that the rate of flow augmentation would stay constant during the pertinent time period. See paragraph (a) page 3 of Plaintiffs' Motion. A second assumption was that all of the flow augmentation for the Snake River would be provided from Dworshak reservoir, the only FCRPS storage facility available to the Snake River within the action area, and because it has no non-federal storage dams downstream which could intercept the augmented flows. A third and related assumption was that for the July 1- August 31st flow augmentation for the Columbia River, the Dworshak water would compose a portion of that needed to meet the Columbia River's total flow (i.e. this water would enter the Columbia River at its confluence with the Snake). A final assumption was that the remainder of the Columbia River flow augmentation would be apportioned between Grand Coulee, Libby, and Hungry Horse reservoirs.

10. The allocation of storage draft to provide additional flow augmentation to the Columbia River involved discretionary decision-making on my part. The apportionment between the three upper Columbia basin FCRPS reservoirs could vary considerably, which would affect the outcome of our analysis. One factor I considered in making the between dam allocation was the amount of available storage at each project during the July 1 – August 31, 2005 time period. Another criterion was how long it could take for the project to refill, or replace the "additional draft" of water after August 31 (i.e.

before project operations would return to "normal"). Another criterion was the location of the reservoir relative to the targeted flow augmentation area. For example, consideration must include practical limitations, including legal, or physical constraints that could affect implementation. [3] Finally, it seemed that the burden of supplying this extraordinary request (not currently called for in the 2005 water management plan for any storage projects), should not be placed wholly on only one federal reservoir and its users. Impacts would be more moderate if they were shared by the three FCRPS storage reservoirs.

11. Using these criteria, I chose to allocate about 60% of the draft needed to Grand Coulee, 27% to Libby and 13% to Hungry Horse. Grand Coulee and Libby each are able to store 5 million acre-feet of water (the largest federal reservoirs), but Grand Coulee can be expected to refill much faster than Libby due to its significantly greater inflow (being much further downstream in the Columbia River basin). As the Study bears out, Hungry Horse has a much more difficult time refilling, and in 5 water conditions out of 50 years, would not refill by September 2006 (i.e. reach the UPA operation elevation). I recognize that other choices or allocations could have been used for the Study, which would have led to somewhat different power revenue estimates – some lower, some higher.

12. Dr. Anderson reported that an increase of 3,000 cfs on the Snake River and 16,000 cfs on the Columbia River would be required to reduce WPTT by 10 percent. Based on that information, we computed the total volume of water needed by multiplying the additional 3,000 cfs of flow in the Snake River times the requested duration of relief

[3] While there are several large Canadian storage reservoirs above Grand Coulee, the Columbia River Treaty with Canada strictly regulates outflows from those projects, and obtaining outflows for operations this year would be impractical, if not impossible, see Declaration of Cynthia Henriksen of the Corps of Engineers.

(72 days), and the additional 16,000 cfs of flow in the Columbia River times 62 days. This additional volume was calculated to be 430 thousand acre-feet (kaf) on the Snake River,[4] and almost 2 million acre-feet (maf) on the Columbia River. Knowing the total volume of water needed, we modeled a constant rate of release for the volumes over the relevant time periods (June 20- August 31 for the Snake, and July 1- August 31 for the lower Columbia). See Plaintiffs' motion for injunctive relief at page 3. - (Plaintiffs requested even distribution throughout the release periods).

13. With the model results, we were able to estimate the amounts of energy produced by the FCRPS with the amended operation for fiscal year 2005 (including both WPTT reduction and increased spill)[5] to compare with energy produced by the operation under the 2004 BiOp. We then determined the net secondary energy revenues (sales and purchases of surplus energy on the open market) expected from the two operations of the FCRPS by applying the projected Mid-Columbia trading hub forecast of energy prices for each month. The difference in the expected net secondary revenues produced by the two scenarios is BPA's estimated cost to BPA ratepayers of these components of the Plaintiffs' motion. The estimated net cost (lost revenue from additional spill applied against increased power revenues due to flow augmentation) to BPA in 2005 was $52 million. However, because some of the additional water drafted from the reservoirs could only be recovered over an extended period of time, BPA ran a second analysis to

[4] The Army Corps of Engineers evaluation came out slightly differently on the necessary Snake River flows. See Declaration of Henriksen. This can be attributed to differences in assumptions and methodologies, and would produce somewhat higher revenue losses.

[5] With just the increased spill alone requested by the Plaintiffs, the impacts to revenue would be much greater; however, because the increased flow I assumed for decreasing WPTT would provide for some additional generation, reducing the revenue impacts, I included these in the total calculations.

determine what costs would accrue to BPA ratepayers for these 2005 operations due to effects lasting into fiscal year 2006.

14. This second analysis (2006 impacts from a summer 2005 operation) used a very different approach than the 2005 modeling effort. The 2005 modeling effort was based on relatively accurate forecasts of the 2005 water year and market conditions (most of the snowpack for this year has already accumulated, and near term prices are more reliable than long-term price forecasts). Both the October 2005 to September 2006 water availability and energy market conditions are much less predictable. To address this uncertainty, we used two long-term forecasting computer models - HYDSIM (a hydro-system simulator) and AURORA (an economic model). HYDSIM takes into account a representative historical range of 50 water conditions (from 1929 to 1978) and AURORA simulates energy market prices over a range of assumed loads, natural gas prices, availability of thermal generating resources and the varying availability of hydroelectric energy for the market due to the 50 varying water conditions.

15. The conclusion of these studies was that, assuming the water condition that will occur in 2006 is near the average of the 50 water conditions we modeled, BPA wholesale customers would be exposed to an additional cost due to less net revenues produced as reservoirs were refilled in FY2006 of $50 million. (The highest and lowest cost in individual years of the 50 years ranged from $74 million to $18 million due to varying water conditions.) Simply put, the effects of the proposed 2005 operations carried over into 2006 (assuming an average water year and average market conditions and resumption of UPA operations) would result in an expected loss of revenues over the two years, FY2005 and FY2006 of $102 million.

16. According to Mr. Michael R. Normandeau, Public Utilities Specialist in BPA's Power Rates group, the impact on BPA's wholesale power customers is approximately $1.52 per MWh, if all $102 million were recovered by BPA in FY 2006. It is possible that some of these costs would instead be recovered in the next rate period (2007-2009), in which case the FY 2006 impact would be lower and the FY 2007-2009 rates would increase. To put this into perspective, BPA's traditional preference customers currently pay approximately $30/MWh without these costs. This is a considerable cost increase, especially taking into account that BPA has already incorporated a significant amount of fish and wildlife costs in its current rates. For example, BPA funds capital investments for fish facilities, operation and maintenance of those facilities, the Council's Fish and Wildlife Program and the costs of running the hydro system for fish operations. The combined net cost that BPA has incorporated in its current rates is almost $600 million annually (a little more than $300 million for hydro system operations and a little less than $300 million for the fish and wildlife funding requirements), or about $8.5/MWh (with a roughly similar split between the cost of hydro operations and the cost of fish and wildlife funding per MWh), which is about 28 percent of the $30/MWh our preference customers pay currently.

17. As described in paragraph 12 above, the hydrosystem modeling for FY2005 also included the proposed spill operation. Specifically, Plaintiffs requested increased spill from (a) June 20, 2005 through August 31, 2005, of water in excess of that required for station service[6] on a 24-hour basis, at each of the four lower Snake River projects; and, (b) from July 1, 2005 through August 31, 2005, of all flows above 50,000

[6] The minimum powerhouse flow levels the Plaintiffs have specified are appropriate for maintaining adequate generators on the electrical system to provide the station service needs of the projects and also provide voltage control and support for the FCRPS electrical transmission system.

cfs, on a 24-hour basis, at McNary Dam.17. Because the Plaintiffs did not specify the amount of flow required for "station service" in their motion for the Snake River projects' injunctive relief, I relied upon their Declarant's definition of "station service".[7] In paragraph 46 of his declaration, Stephen W. Pettit states,

> "Specifically, the plaintiffs seek an order requiring spill of water at the four lower Snake projects on a 24-hour basis except for the amount of water necessary for what is called "station service." Generally, this means operating one of the units at each project to generate at least enough electricity to operate that project. For three of the lower Snake projects, station service requires approximately 11.5 kcfs of flow and at Ice Harbor, station service requires between 7.5 and 9.5 kcfs."

In paragraph 48, Pettit states,

> "On the Columbia, plaintiffs seek only a change in spill at McNary Dam. Spill at the remaining projects would be as called for in the 2000 BiOp RPA (which is also what is suggested in the 2004 BiOp). At McNary, plaintiffs ask the Court to order all water above 50 kcfs to be spilled during the summer migration season."

18. BPA's modeling of the effects of Plaintiff's requested spill operation was compared to the UPA/2004 BiOp operation. In the action agencies UPA, no summer spill is provided at the collector projects (Lower Granite, Little Goose, Lower Monumental, and McNary), but spill is included at Ice Harbor. The difference in energy production of the BiOp compared to Plaintiffs' Motion, which increases spill and decreases hydropower generation, results in a lower power revenue (included in the $102 million revenue loss referenced above).

19. BPA also expects that the Plaintiff's proposed flow augmentation would compel reductions to the operating transfer capability of the high voltage transmission facilities used to deliver power to California and cause BPA to incur additional revenue losses due to revised operating conditions of BPA's transmission facilities. Mr. Michael

[7] Plaintiffs' Motion does specify what spill level should be provided at McNary – all flow above 50,000 cfs.

R. Viles, an electrical engineer in BPA's Transmission Business Line (TBL) Technical Operations Staff, has analyzed those effects. He concludes that increased loading on parts of the existing transmission system due to generation dispatches from the different FCRPS projects needed to accommodate the Plaintiff's proposed flow augmentation will cause increased transmission losses. In order to continue to meet mandated industry reliability standards in the event of system contingencies, such as an outage of a line or loss of generation resource, the higher transmission losses will likely result in BPA reducing the operating transfer capability of the California-Oregon Intertie (COI) and the Pacific DC Intertie (PDCI) when line loadings on the transmission system north of the John Day Dam increase. BPA must reduce the transfer capability of the COI and PDCI transmission facilities because only so much power can reliably move through the transmission system under such conditions. Therefore, if line loadings in one part of the transmission system increase (such as north of John Day), this increased demand reduces the transfer capability through other parts of the transmission system (such as the COI and the PDCI). Mr. Viles has estimated a loss of up to $1.2 million in transmission revenues to BPA could result if the Plaintiff's proposed flow augmentation is adopted for the summer of 2005.

20. BPA's modeling of the effects of Plaintiff's motion was limited to the scenario wherein the Court granted Plaintiffs' request for relief through increased spill and decreased WPTT in summer 2005. If the proposed 2005 summer operation were implemented in a more normal water condition than 2005, the expected cost would be higher. Using my professional judgment, I estimate that the annual expected loss of net secondary revenues to the FCRPS would amount to somewhere in the $100 - $150

million range in a normal water condition. Mr. Normandeau estimated the yearly cost impact on BPA's wholesale customers in that circumstance; assuming that the loads BPA serves remain the same, to be approximately $1.49 to $2.23/MWh.

I declare under penalty of perjury that the foregoing is true and correct. Executed on April 22, 2005, in Portland, Oregon.

Roger B. Schiewe

Roger Schiewe