SECTION 7(b)(2)

RATE TEST STUDY

PREPARED BY

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COMMONLY USED ACRONYMS

AC	Alternating Current
ACME	Accelerated California Market Estimator (computer program)
AFUDC	Allowance for Funds Used During Construction
aMW	Average Megawatt
APS	Ancillary Products and Services (rate)
ASC	Average System Cost
ASM	Aluminum Smelter Model
BASC	BPA Average System Cost
BTU	British Thermal Unit
CE	Emergency Capacity (rate)
CF	Firm Capacity (rate)
CO-OP	Co-operative Electric Utility
COB	California-Oregon Border
COE	United States Army Corps of Engineers
Con/Mod	Conservation Modernization Program
COSA	Cost of Service Analysis
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CWIP	Construction Work In Progress
CY	Calendar Year (Jan - Dec)
DC	Direct Current
DOE	Department of Energy
DSIs	Direct Service Industrial Customers
DSM	Demand-Side Management
EA	Environmental Assessment
ECC	Energy Content Curve
EIS	Environmental Impact Statement
ET	Energy Transmission (rate)
F & O	Financial and Operating Reports
FBS	Federal Base System
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
FPS	Firm Power Products and Services (rate)
FPT	Formula Power Transmission (rate)
FSEA	Federal Secondary Energy Analysis
FY	Fiscal Year (Oct - Sep)
GCPs	General Contract Provisions

GRSPs	General Rate Schedule Provisions
GTRSPs	General Transmission Rate Schedule Provisions
IDUEIS	Intertie Development and Use Environmental Impact Statement
IE	Eastern Intertie Transmission (rate)
IN	Northern Intertie Transmission (rate)
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (rate)
IR	Integration of Resources (rate)
IRE	Industrial Replacement Energy
IS	Southern Intertie Transmission (rate)
ISAAC	Integrated System for Analysis of Acquisitions (computer program)
ISC	Investment Service Coverage
KV	Kilovolt (1000 volts)
KW	Kilowatt (1000 watts)
kWh	Kilowatthour
LDD	Low Density Discount
LOLP	Loss of Load Probability
LTIAP	Long-Term Intertie Access Policy
M/kWh	Mills per kilowatthour
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
MW	Megawatt (1 million watts)
MW-miles	Megawatt-miles
MWh	Megawatthour
MT	Market Transmission (rate)
NEPA	National Environmental Policy Act
NF	Nonfirm Energy (rate)
NFRAP	Nonfirm Revenue Analysis Program (computer program)
NOB	Nevada-Oregon Border
NR	New Resource Firm Power (rate)
NTSA	Non-Treaty Storage Agreement
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OY	Operating Year (Jul - Jun)
PA	Public Agency
PIP	Programs in Perspective
PF	Priority Firm Power (rate)
PMDAM	Power Market Decision Analysis Model
PNCA	Pacific Northwest Coordination Agreement

PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
PSW	Pacific Southwest
PURPA	Public Utilities Regulatory Policies Act
PUD	Public or Peoples' Utility District
RAM	Rate Analysis Model (computer model)
REVEST	Revenue Estimate (computer program)
ROD	Record of Decision
RP	Reserve Power (rate)
RPSA	Residential Purchase and Sale Agreement
SAM	System Analysis Model
SI	Special Industrial Power (rate)
SPM	Supply Pricing Model (computer program)
SPOM	Surplus Power-Open Market
SS	Share-the-Savings Energy (rate)
TGT	Townsend-Garrison Transmission (rate)
UFT	Use of Facilities Transmission (rate)
USBR	United States Bureau of Reclamation
VI	Variable Industrial Power (rate)
VOR	Value of Reserves
WNP	Washington Public Power Supply System (Nuclear) Project
WPPSS	Washington Public Power Supply System
WPRDS	Wholesale Power Rate Development Study
WSPP	Western Systems Power Pool
WSCC	Western Systems Coordinating Council

1. INTRODUCTION

Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839e(b)(2), directs the Bonneville Power Administration (BPA) to conduct, after July 1, 1985, a comparison of the projected rates to be charged its preference and Federal agency customers for their firm power requirements, over the rate test period plus the ensuing 4 years, with the costs of power (hereafter called rates) to those customers for the same time period if certain assumptions are made. The effect of this rate test is to protect BPA's preference and Federal agency customers' wholesale firm power rates from certain specified costs resulting from provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the general requirements loads of preference and Federal agency customers to other BPA loads.

The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's public body, cooperative, and Federal agency customers (7(b)(2) customers). The two sets of rates are: (1) a set for the test period and the ensuing 4 years assuming that section 7(b)(2) is not in effect (program case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (7(b)(2) case rates). Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are subtracted from the program case rates. Next, each nominal rate is discounted to the beginning of the test period of the relevant rate case. The discounted program case rates are averaged, as are the 7(b)(2) case rates. Both averages are rounded to the nearest tenth of a mill for comparison. If the average program case rate is greater than the average 7(b)(2) case rate, the rate test triggers. The difference between the average program case rate and the average 7(b)(2) case rate determines the amount to be reallocated from the 7(b)(2) customers to other BPA loads in the rate proposal test period.

1.1 Purpose and Organization of Study

The purpose of this study is to describe the application and results of the section 7(b)(2) rate test methodology. If the 7(b)(2) rate test triggers, the cost adjustment amount that is to be incorporated into the rate design process is calculated. The accompanying Documentation for the 7(b)(2) Rate Test Study, WP-96-FS-BPA-07A, contains the documentation of the computer program and data used to perform the 7(b)(2) rate test.

This study is organized into two major sections. The first section describes the methodology used in conducting the rate test. It provides a discussion of the calculations performed to project the two sets of power rates and the results of the rate test for the 1996 rate proposal. The second section presents a set of tables that illustrates the calculations performed for the rate test and the results of the test. The financing benefits analysis is included as an appendix to this study.

1.2 Basis of Study

1.2.1 Legal Interpretation. As the first phase of its 1985 general rate case, BPA published the Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act, 49 FR 23,998 (1984). Major provisions of the Legal Interpretation are listed below:

1.2.1.1. The 7(b)(2) case is modeled by limiting the differences between the two cases to only five assumptions specified in section 7(b)(2) and the unavoidable natural consequences of these assumptions on the results of ratesetting processes that remain the same between the program case and the 7(b)(2) case.

1.2.1.2. BPA will reallocate costs resulting from the rate test trigger, pursuant to section 7(b)(3), in a manner that is consistent with section 7(a) of the Northwest Power Act.

1.2.1.3 Applicable 7(g) costs are subtracted from the program case rates before those rates are compared with the rates in the 7(b)(2) case.

1.2.1.4 "Within or adjacent" direct-service industrial customer (DSI) loads are assumed to be served by the 7(b)(2) customers for the entire rate test period.

1.2.1.5 The DSI loads assumed to be served by the 7(b)(2) customers are assumed to be served wholly with firm power.

1.2.1.6 Appendix B to S. Rep. No. 272, 96th Cong., 1st Sess. (1979), is used to determine which DSI loads are "within or adjacent" to 7(b)(2) customer service areas, with modifications to reflect the actual status of BPA service to the DSIs.

1.2.1.7 To determine "Federal base system resources not obligated to other entities," DSI loads not "within or adjacent" are assumed to receive service from non-7(b)(2) customers as the pre-Northwest Power Act BPA-DSI power sales contracts expire.

1.2.1.8 Section 7(b)(2)(D) identifies three types of additional resources that are assumed, in the 7(b)(2) case, to meet the 7(b)(2) customers' loads after the Federal base system (FBS) resources are exhausted. Specific additional resources are assumed to be used in the order of least cost first; generic resources then are used if necessary.

1.2.2 <u>Implementation Methodology</u>. A hearing pursuant to section 7(i) of the Northwest Power Act was held during 1984 on implementation methodology issues. The issues addressed in the hearing are discussed in the Administrator's Record of Decision for Section 7(b)(2) Implementation Methodology (7(b)(2) ROD), published in August 1984. Each is summarized below.

1.2.2.1 Reserve benefits provided under the Northwest Power Act are quantified using the same value of reserves analysis used in the relevant rate case, modified to reflect the fact that "within or adjacent" DSI loads are less than the total amount of DSI loads served by BPA. In addition, a financing benefits analysis is performed for the resources used to quantify the value of reserves.

1.2.2.2 Financing benefits in the 7(b)(2) case are quantified for planned or existing resources that have been acquired by BPA or are planned to be acquired in the program case during the 7(b)(2) rate test period. The financing benefits in the 7(b)(2) case are estimated by a consultant who estimates the sponsor's financial cost for the 7(b)(2) case resources assuming that BPA did not acquire the resource output. The financing benefits in the program case for those resources required to meet the 7(b)(2) customers' loads may increase the costs of those resources in the 7(b)(2) case. When ownership of a resource is by non-preference customers, or is unidentifiable, the resource is assumed to be financed by a proxy financing entity comprised of all of the region's preference utilities, with shares in proportion to the utilities' firm power loads.

1.2.2.3 Natural consequences result from reflecting the five specific section 7(b)(2) assumptions in the 7(b)(2) case rates while keeping all the underlying ratesetting premises and processes the same for both cases. Three natural consequences were identified for possible modeling in the rate test: elasticity of demand, the level of surplus firm power available, and the size of nonfirm energy markets.

1.2.2.4 BPA's Supply Pricing Model (SPM) is used to model the rate test. The model is generally the same as that used to conduct the rate test for BPA’ s 1985 and 1987 general rate filings, the 1991 Initial Rate Proposal, and the 1993 general rate filing. The model has not significantly changed from the 1993 rate case to the 1996 rate case.

1.2.2.5 The projected rate for each year of the section 7(b)(2) rate test period is discounted back to the rate proposal test period, using a factor based on BPA's projected borrowing rate for each of the rate test years. The discounted rates then are averaged for each case and the result rounded to the nearest tenth of a mill. The rate test triggers if the average of the discounted rates for the program case exceeds the average of the discounted rates for the 7(b)(2) case by one tenth of a mill or more. If the rate test triggers, the difference between the two rates is multiplied by the general requirements of the preference customers in the test year to determine the amount of costs to be reallocated from the preference customers to other BPA loads in the test year.

2. METHODOLOGY

Implementing section 7(b)(2) consists of incorporating the determinations from the Legal Interpretation and the Implementation Methodology Record of Decision into the SPM.

2.1 Sequence of Steps

The SPM simulates BPA's ratesetting process by performing the steps needed to develop wholesale power rates. Each step is described as it is performed to calculate rates for the program case and the 7(b)(2) case.

2.1.1 Program Case. This scenario models, as closely as possible, the 1996 Rate Case rate test period (FY 1997-2001) and the following 4 years (FY 2002-2005). The results of the program case for the rate case test period closely approximate the results of the 1996 Rate Case Final Rate Proposal.

2.1.1.1 Loads. The load forecast used to develop rates for the program case covers the period FY 1997 through FY 2005, and is the same forecast used to develop BPA's 1996 Final Rate Proposal. Loads were developed for the region's publicly owned non-generating and generating utilities using econometric models. Investor-owned utility (IOU) loads were obtained from BPA’ s updated version of the 1991 joint BPA/Northwest Power Planning Council forecast including a modified version of the residential sector model. Exchange loads were obtained from information provided by the utilities themselves. DSI loads were forecasted on an aggregate basis for those DSI's that are "within or adjacent" to BPA's service area and for those that are not. The DSI forecast includes only those DSIs that will be served by BPA during the 7(b)(2) rate test period. Loads for Federal agencies and capacity/energy exchanges are contractually determined and are input to the SPM.

The net load placed on BPA by public utilities is determined by subtracting the capability of those utilities' own resources and other purchased power from the utilities' total loads. IOU loads projected to be placed on BPA were obtained from the firm resource exhibits contained in each utility's power sales contract with BPA. Total loads placed on BPA are comprised of public utility, IOU, DSI, Federal agency, residential exchange, and contractual loads. All forecasted loads are entered into the SPM on an annual average energy basis. Documentation for these forecasts of regional power loads appears in the 1996 Loads and Resources Study and Documentation, WP-96-FS-BPA-01, -01A, and -01B.

2.1.1.2 Resources. Resources also are projected for the entire region. Existing public, IOU, and Federal hydro capabilities are input to the SPM assuming critical water conditions and assuming some nonfirm energy generation. Hydro resources capability is constrained by the agreement reached by BPA with NMFS, the Regional Council, and DOE to cap fish costs at $435 million. Existing hydro operation and maintenance costs and debt interest and amortization costs are input for public and private utilities. Thermal plants are input on a plant by plant basis. The capability of each resource is the same as used in the 1996 rate proposal. Other data that are input to the SPM include each plant's capital cost, debt and/or equity financing rate, on-line date, and plant factor. Exchange resources are the same as the exchange loads for both IOUs and public utilities and reflect the deeming or suspension status of each utility.

The resources used for the program case are consistent with the resources used for the 1996 rate proposal. Documentation for the resources appears in the 1996 Loads and Resources Study and Documentation, WP-96-FS-BPA-01, -01A, and -01B. BPA resources are apportioned among three resource pools: (1) FBS; (2) exchange; and (3) new resources.

2.1.1.3 Load/Resource Balance. The SPM determines a load/resource balance for the entire region. For the program case, however, the BPA portion is particularly significant because it determines how costs are allocated. Resources are allocated to serve loads in the order prescribed by the Northwest Power Act. The FBS serves Priority Firm Power (PF) loads (contract, Federal agency, public utility, and exchange loads) until FBS resources are exhausted. Exchange resources then are used to serve any remaining PF load. DSI, New Resource, and Surplus Firm Power loads are combined into a single rate pool. Remaining exchange and new resources are used to serve this combined rate pool.

2.1.1.4 Revenue Requirement. Repayment studies for generation and transmission costs were run for each of the years in the 7(b)(2) rate test period. For the outyears, repayment studies are run to determine the interest and amortization schedule of the Federal debt for generation, conservation, and transmission investments. Outyear projections of debt service on the net-billed projects, the Idaho Falls Project, and the Cowlitz Falls Project are input to the SPM. The remaining outyears' program costs are estimated by the BPA program offices.

FBS costs are based on the interest and amortization of the Federal debt for the hydro projects; planned net revenues; hydro operation and maintenance costs; costs related to WNP-1, -2, and -3, not including the costs associated with the WNP-3 Settlement Agreement; fish and wildlife costs; costs of the Hanford and Trojan nuclear plants; and costs of hydro efficiency improvements. Exchange resource costs are based on the average system cost (ASC) of utilities participating in the residential exchange, including cost adjustments for deeming utilities. New resource costs are those of the Idaho Falls contract, the generation portion of competitive acquisitions, geothermal, the

Cowlitz Falls Project, and firm purchased power. Other BPA costs include BPA administrative and general costs, short-term purchase power costs, the costs associated with the WNP-3 Settlement Agreement, and the costs associated with BPA conservation and billing credits. Transmission costs are reduced by costs allocated to wheeling and other adjustments.

2.1.1.5 Cost Allocation. Allocation of projected costs to customer classes is performed on an average energy basis in the SPM. Generation costs are allocated according to the results of the load/resource balance, as previously described. Conservation and billing credit costs, BPA administrative and general expenses, energy service business revenues, and WNP-3 Settlement Agreement costs are allocated across all BPA firm loads. Federal transmission costs are allocated to customers served with Federal resources. Transmission costs related to exchange resources are allocated together with exchange generation costs. In general, the cost allocation procedures for the program case are the same as those for the 1993 rate proposal.

2.1.1.6 Rate Design. The adjustments made to allocated costs in the SPM for the program case parallel those made in the 1996 Rate Proposal. These adjustments include excess revenue credits; the WNP-3 credit; the surplus firm power revenue deficiency; the capacity revenues credit; the section 7(c)(2) delta and margin; the DSI floor rate adjustment; and the exchange cost adjustment. Rate design adjustments are discussed in general below.

Excess revenues are earned from the sale of nonfirm energy that is made available by the assumption of the average of 50 water years for nonfirm energy generation capability. The SPM contains a subroutine to calculate the expected percentage service to specified nonfirm energy markets in the following order of priority: displacement of combustion turbines related to the WNP-3 settlement; displacement of firm purchases; displacement of regional high-cost thermal generation; exports to the Pacific Southwest (PSW); and displacement of regional low-cost thermal generation. The SPM calculates an annual average nonfirm energy rate, which is a percentage of the forecasted gas price capped by the average cost of nonfirm energy. This rate is applied to calculated sales of nonfirm energy to displace BPA firm purchases, high-cost thermal, and PSW sales. Low-cost thermal displacement sales are assumed to be made at a low Market Expansion rate. Excess revenues are credited to loads served by FBS and new resources.

The WNP-3 credit accounts for the revenues BPA expects to receive from the sale of power to the IOUs in fulfilling the WNP-3 Settlement Exchange Agreement. The revenues that result from applying the contracted rate to the load are allocated to all firm loads.

BPA assumes that all DSI load placed on BPA under new contracts is 100 percent firm.

The surplus firm power revenue deficiency results when less than all of the available surplus firm power is sold at its fully allocated cost. BPA forecasts that a portion of the prior DSI First Quartile load released by waiver agreements will sign SP contracts. In addition, BPA assumes that the contracts with Southern California Edison, Puget Sound Power and Light, the cities of Burbank, Glendale, and Pasadena, and the Modesto Irrigation District, City of Santa Clara and City of Redding will continue in the power sales mode, at amounts and rates set by the individual contracts. The fully allocated cost of the surplus firm power, less the revenues received from the sale of that surplus, equals the surplus firm power revenue deficiency. The deficiency is allocated to all firm loads, including sales of surplus firm power at full cost. The revenues from capacity sales are also treated like the surplus firm power revenue deficiency and are allocated to all firm loads.

The 7(c)(2) adjustment is made to account for the difference between the costs allocated to the DSIs and the revenues resulting from the applicable DSI rate. A net margin is used in determining the applicable DSI rate. The net margin subsumes the value of reserves credit and the typical margin adjustment. The net margin is -2.66 mills/kWh in nominal dollars.

The floor rate test ensures that the DSI rate will not be lower than the Industrial Firm Power rate in effect for Operating Year 1985, pursuant to section 7(c)(2) of the Northwest Power Act. If the DSI rate is below that floor rate, the DSI rate is raised to the floor rate and an adjustment is necessary to credit additional revenues from the DSIs to other firm power customers.

The exchange cost adjustment alters BPA's revenue requirement because the assumed average PF rate used in the Revenue Requirement Study differs from the average PF rate calculated in the SPM. Changes in the PF rate result in changes in the cost of the exchange. The SPM repeats the exchange cost calculation several times to reflect changes in the PF rate due to subsequent cost allocations.

No specific adjustment is made in the SPM for the Low Density Discount.

2.1.2 7(b)(2) Case. The 7(b)(2) case is modeled in the same way as the program case except where section 7(b)(2) of the Northwest Power Act requires specific assumptions to be made that modify the program case.

2.1.2.1 Loads. The loads input to the SPM to calculate rates for the 7(b)(2) case are the same loads used in the program case, with the following modifications. The 7(b)(2) case utility loads are adjusted to exclude estimates of programmatic conservation savings, competitive acquisitions conservation or billing credits. The 7(b)(2) case also excludes exchange loads. "Within or adjacent" DSI loads, adjusted to exclude estimates of the Conservation/Modernization program, are transferred to the service territories of the preference customers for the entire rate test period as 100 percent firm loads. DSI loads not "within or adjacent" are transferred to IOU service as the pre-Northwest Power Act BPA-DSI power sales contracts expire. DSI loads that continue to be served by BPA are served at the contract rate; loads of the 7(b)(2) customers are served at the 7(b)(2) rate. The contract rate is based on costs from FBS resources, transmission, on-line conservation, O&M, and rate design adjustments. The 7(b)(2) rate is based on costs from remaining FBS resources, new resources, transmission, on-line conservation, O&M, and rate design adjustments.

2.1.2.2 Resources. The FBS is identical for the two cases, as are existing resources owned by the public utilities and IOUs. If the FBS is insufficient to serve all BPA firm loads through the test period, additional resources are required. Consistent with the 7(b)(2) ROD, three types of additional resources can be added to serve loads. The first type is actual and planned acquisitions by BPA from 7(b)(2) customers consistent with the program case. The second type is existing 7(b)(2) customer resources not dedicated to serve their regional loads. These first two types of resources are assumed to be used in order of least cost first and include BPA programmatic conservation, other resources from BPA's Resource Program, and the nondedicated resources. The third type of additional resources is generic resources based on the costs of resources acquired by BPA from non-7(b)(2) customers consistent with the program case. These resources are brought on-line if the first two types of resources are insufficient to meet the 7(b)(2) requirements. However, the first two types of resources are sufficient through the current rate test period.

The financing benefits analysis required by section 7(b)(2)(E)(i) of the Northwest Power Act was performed by BPA's financial advisor, Alex. Brown & Sons, Inc. The financial advisor’ s analysis appears as the Appendix A to this document. It shows that the estimated financing benefit of BPA's participation in resource acquisitions of non-BPA sponsored conservation and generation resources by the public utilities is 14 basis points. This increases the financing costs for additional resources in the 7(b)(2) case and increases the 7(b)(2) case power cost of the 7(b)(2) customers. For the Cowlitz Falls Project, the estimated benefit of BPA's participation is 24 basis points between an assumed revenue bond issued with and without a BPA contract for the Project. Two categories of resources, BPA-sponsored programmatic conservation and resources acquired from non-7(b)(2) customers, have a lower cost of financing in the 7(b)(2) case because the public agency is eligible for a tax exempt financing rate which is lower than the program case BPA Treasury rate and London Interbank Offering Rate for the respective resources. BPA-sponsored programmatic conservation and non-7(b)(2) customer resources have disbenefits of 131 basis points and 47 basis points, respectively.

The debt associated with the Idaho Falls project was refunded to take advantage of lower interest rates. However, since the owner of the project, the City of Idaho Falls, can withdraw from the contract at its option, the new interest rate is not affected by Idaho Falls' contractual relationship with BPA. Therefore, no financing differential is associated with Idaho Falls.

Alex. Brown & Sons, Inc. also analyzed the financing associated with the combustion turbines used in the determination of reserve benefits. The reserve benefits analysis is discussed in the rate design paragraph below.

2.1.2.3 Load/Resource Balance. The FBS is first used to serve any existing pre-Northwest Power Act contracts. The remaining FBS is then used to serve the load of the 7(b)(2) customers. Since the remaining FBS is sufficient to meet the 7(b)(2) load, no new resources are added in accordance with section 7(b)(2) the Northwest Power Act as described in the Resources paragraph above.

2.1.2.4 Revenue Requirement. The revenue requirement in the 7(b)(2) case is comprised for the most part of the same costs and budget information as that in the program case. Excluded from the program case revenue requirement are: amounts budgeted for conservation and direct acquisitions, including both generation and transmission investments; and residential exchange costs. Repayment studies are then performed for each year of the 7(b)(2) rate test period using the same method as for the program case.

2.1.2.5 Cost Allocation. Cost allocation is performed for the 7(b)(2) case according to the load/resource balance, as described above. Customers buying power under pre-Northwest Power Act contracts are allocated costs of the FBS according to their use of the resource. Section 7(b)(2) customers are allocated costs of the FBS and new resource costs according to their use of the respective resources. Purchasers of surplus firm power are allocated new resource costs according to their use of the respective resource.

2.1.2.6 Rate Design. Reserve benefits are mentioned in section 7(b)(2)(E)(ii) of the Northwest Power Act. The full value of reserve is used to quantify these benefits. The 1996 Supplemental Rate Proposal performs a value of reserves analysis, resulting in a value of $53.3 million.

Two other factors influence the cost of the required reserves. First, a financing benefits analysis was performed by BPA's financial advisor for the combustion turbines that are assumed to provide forced outage reserves. The new financing benefits analysis continues to indicate that public utilities could have borrowed the capital required for construction of the combustion turbines at interest rates lower than those assumed by BPA in the value of reserves analysis. Therefore, the value of reserves is lower by the reduction in debt service on the combustion turbines when the lower interest rate is applied to the capital cost.

Second, the value of reserves for each year was reduced by the proportion of DSI loads that are not "within or adjacent" in order to yield the amount to be allocated to the 7(b)(2) customers.

The algorithms in the SPM that allocate nonfirm energy and open market surplus firm energy to markets are the same in the 7(b)(2) case as in the program case. The amount of open market surplus firm energy available in the 7(b)(2) case is different from that in the program case, however, because of the different load/resource balance. In the 7(b)(2) case, open market surplus sales will take place only in the situation where the remaining energy after serving firm loads is greater than surplus firm contracts. The markets for nonfirm energy also are different in the 7(b)(2) case because of the movement of DSI load to public agencies and IOU service territory. These differences from the program case are the two (out of three mentioned in the 7(b)(2) ROD) natural consequences that are incorporated in the 1996 rate test.

Other rate adjustments in the 7(b)(2) case are performed in the same manner as in the program case.

2.2 Summary of Results

Results of the SPM runs for the two cases are summarized in Tables 1 and 2.

2.2.1 Program Case. The program case rate for each year is based on the costs of the resources used to serve the 7(b)(2) customers, as determined by the load/resource balance performed in the SPM to simulate the load/resource balance in the 1996 Final Proposal. The resource costs are then adjusted, as described above and in the 1996 Final Proposal. Table 1 shows the projection of undiscounted nominal program case rates.

2.2.2 7(b)(2) Case. The annual amount to be paid by 7(b)(2) customers for their power needs in the 7(b)(2) case is based on the cost of FBS resources and the cost of additional new resources. These power costs include added costs for reserves and financing, i.e., the absence of the reserve benefits and financing benefits implicit in the cost of power in the program case. The power costs are then subject to the same cost and revenue adjustment allocations as the program case rates. Table 2 shows the projection of undiscounted nominal 7(b)(2) case rates.

2.2.3 The Rate Test. The SPM performs the section 7(b)(2) rate test after it calculates the two sets of rates. First, the projected program case rates are reduced by the applicable 7(g) costs for each year. The applicable 7(g) costs are described in section 7(b)(2): "conservation, resource and conservation credits, experimental resources and uncontrollable events." The 7(g) costs quantified for the 1996 supplemental rate test are comprised of BPA acquired and projected conservation and billing credits. The projected rates for each year then are discounted to FY 1997 using factors based on BPA's projected borrowing rate for each year. Table 3 shows BPA's future borrowing rates that were used in the discounting procedure, and the corresponding cumulative discount factors. The discounted rates for each case then are averaged over the test period, rounded to one decimal place, and compared (Table 4).

As shown in Table 4, the rate test triggers. Therefore, a rate adjustment is required.

TABLE 1
PROGRAM CASE RATES
(nominal mills/kWh)

Line No.	Fiscal Year	A Rate	B Applicable 7(g) Costs	C Net Rate */
1	1997	25.624	1.646	23.978
2	1998	27.148	1.788	25.360
3	1999	27.887	1.695	26.192
4	2000	28.323	1.658	26.665
5	2001	28.028	1.645	26.383
6	2002	26.937	1.638	25.299
7	2003	28.274	1.624	26.650
8	2004	28.061	1.545	26.516
9	2005	28.137	1.505	26.632

*/ Column A minus Column B.

TABLE 2
7(b)(2) CASE RATES
(nominal mills/kWh)

Line No.	Fiscal Year	A 7(b)(2) Rate
1	1997	17.633
2	1998	20.172
3	1999	21.293
4	2000	21.896
5	2001	22.378
6	2002	21.902
7	2003	23.441
8	2004	22.941
9	2005	22.900

TABLE 3
DISCOUNT FACTORS FOR THE RATE TEST

Line No.	Fiscal Year	A Annual BPA Borrowing Rate 1/	B Cumulative Discount Factor 2/
1	1997	.0748	.9304
2	1998	.0740	.8663
3	1999	.0763	.8049
4	2000	.0775	.7470
5	2001	.0772	.6935
6	2002	.0764	.6442
7	2003	.0758	.5988
8	2004	.0752	.5570
9	2005	.0747	.5183

1/ 1996 Revenue Requirement Study, WP-96-E-BPA-02.
2/ Column B_t = Column $B_{t-1}/(1 + \text{Column } A_t)$; Fiscal Year 1996 equals 1.

TABLE 4
COMPARISON OF RATES FOR TEST
(1997 mills/kWh)

Line No.	Fiscal Year	A Discounted Program Case Rate	B Discounted 7(b)(2) Case Rate
1	1997	22.309	16.406
2	1998	21.970	17.475
3	1999	21.082	17.138
4	2000	19.919	16.356
5	2001	18.296	15.518
6	2002	16.299	14.110
7	2003	15.959	14.038
8	2004	14.768	12.777
9	2005	13.802	11.868
10	Average Rate	18.3	15.1
11	Difference of Average Rates		3.2

APPENDIX A

SECTION 7(b)(2) RATE TEST STUDY

FINAL REPORT

TO

BONNEVILLE POWER ADMINISTRATION

ON

ESTIMATED FINANCING COSTS

FOR

SECTION 7(b)(2) RATE TEST

ALEX. BROWN & SONS
INCORPORATED

APPENDIX TO:

DOCUMENT WP-96-FS-BPA-07

SECTION 1

PURPOSE OF REPORT

The purpose of this report is to provide a summary of our conclusions and major assumptions concerning the "...reduced public body and cooperative financing costs..." as described in Section 7(b)(2)(E)(i) ("7(b)(2)") of the Pacific Northwest Electric Power Planning and Conservation Act (the "Act").

In providing the enclosed summary of our conclusions and major assumptions, we have relied upon our professional experience and expertise in matters concerning the overall credit markets, the activities of the Bonneville Power Administration ("Bonneville") and other public and private utilities in the Pacific Northwest.

Information utilized in reaching the conclusions contained herein rely, in part, on assumptions concerning historic valuation of reserve benefits; expected future resource acquisition costs, and the timing thereof, for Bonneville from fiscal years 1996-97 through 2004-05; and the ownership shares in the hypothetical financing entity established for the purposes of applying the 7(b)(2) methodology. In all other matters, we have made only those assumptions which are consistent, in our opinion, with generally accepted conclusions concerning the credit markets and the conditions under which resource acquisition programs similar to that envisioned by Bonneville would likely occur.

SECTION 2

INTRODUCTION

The Act requires that the Administrator of Bonneville periodically review and revise the rates for the sale of Federal power and for the transmission of non-Federal power. As part of the process of reviewing and revising the power rates to be charged its preference, direct service industry ("DSI"), regional investor-owned utilities and other customers, the Administrator must follow the requirements of Section 7(b)(2) of the Act. Section 7(b)(2)(E) requires that the Administrator assume that:

> "the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from-reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal Base System resources, identified under subparagraph (D) of this paragraph and reserve benefits as a result of the Administrator's actions under this Act were not achieved."

Section 7(b)(2)D specifies the assumptions to be made to meet public body, cooperative and Federal agency customer ("7(b)(2) Customers") loads. After meeting contractual obligations with Federal Base System resources, additional resources can be added to meet loads of the 7(b)(2) Customers. These additional resources can include: actual and planned resources acquired from 7(b)(2) Customers; existing 7(b)(2) Customer resources not dedicated to their own loads; and generic resources acquired from non 7(b)(2) Customers. These resources are assumed to include any conservation programs undertaken or acquired by Bonneville.

The financing benefits of constructing the reserves relates to the load of the DSI customers. The current DSI contracts provide the Federal Columbia River Power System ("FCRPS") with reserves through Bonneville's ability to restrict or interrupt portions of the DSI loads. In the 7(b)(2) case, the DSI loads are served by utilities in the Northwest instead of Bonneville. The 7(b)(2) rate test also requires the assumption that these utilities would have to provide their own reserve resources, and that the utilities would finance reserve resources without Bonneville participation. In other words, Bonneville's analysis of the value of the restriction rights in its rate cases contains the assumption that the financing costs associated with such reserves would be different were reserves acquired by regional utilities.

This report provides our conclusions concerning financing costs for Bonneville's public body, cooperative and Federal agency customers arising from an application of the 7(b)(2) assumptions contained in the Act. The conclusions presented in this report represent our opinions as investment bankers familiar with the domestic credit markets and with bond issues for both public power agencies and investor-owned utilities in the Pacific Northwest. Given the assumptions noted in this report, our conclusions represent the most probable situation, had the hypothetical situation described in the Act occurred.

SECTION 3

EXECUTIVE SUMMARY

This report derives estimates of the interest rate differentials associated with the different classes of resources identified in Section 7(b)(2) of the Act with and without a Bonneville contract. The results are summarized as follows:

Resource	Program Case Interest Rate With BPA Backing	7(b)(2) Case Interest Rate Without BPA Backing	Interest Rate Differential (basis points)
Named			
Idaho Falls	N/A	9.00%	N/A
Cowlitz Falls(1)	5.61%	5.85%	24 basis points
McNary Fishway	5.36%	5.51%	15 basis points
Conservation			
Bonneville Sponsored	9.68% (5)	8.37%	(131 basis points)
Other Public (2)	8.23% (6)	8.37% (7)	14 basis points
Generation			
Public (3)	8.23%	8.37%	14 basis points
Non-7(b)(2) (4)	8.84%	8.37%	(47 basis points)

N/A = Not Applicable.
(1) Reflects refunding issue sold August 24, 1993.
(2) Includes Billing Credits (Conservation and Generation) and Competitive Resource Acquisitions (Conservation).
(3) Includes Competitive Resource Acquisitions (Generation).
(4) Includes resources acquired from non-7(b)(2) customers such as independent power producers.
(5) Fiscal 1982-1995 average Bonneville historic long term interest rate.
(6) From page A-16.
(7) From page A-21.

The Program Case Interest Rates and 7(b)(2) Case Interest Rates shown above are derived from historic borrowing cost and interest rate information compiled for the purposes of the Section 7(b)(2) rate test. The interest rate differentials are indicative of the interest rate differentials for projected borrowing costs for the period encompassing Bonneville's current rate case.

SECTION 4

ASSUMPTIONS

In making our assumptions, we have used the types of financing that most likely would be or could have been used at the time of funding the hypothetical resources acquired according to the terms of the 7(b)(2) rate test. We have relied upon only those most common and accepted legal and financing structures for the hypothetical public financing entity that the 7(b)(2) Customers are assumed to have formed. Similarly, discrete borrowings undertaken by 7(b)(2) customers and non-7(b)(2) customers, would be assumed to be financed using customary public financing methods for long-term fixed rate financing. Such assumptions as to legal and financing structure represent, in our opinion, the most prevalent means for financing large scale resource acquisition programs similar to what Bonneville or its customers could have undertaken or would utilize in the future.

As noted above, the Act requires that an estimate be provided of the financing costs to customers in the 7(b)(2) case because the customers themselves would have to finance the acquisition of additional resources needed to meet their firm loads after Bonneville's Federal Base System resources are exhausted. Initially, to replace reserve benefits provided by the DSI load, the benefits are estimated assuming that the 7(b)(2) Customers acquired peaking facilities in fiscal year 1981-82. An assumption has been made, with which we concur, that the 7(b)(2) Customers would have formed a joint operating agency (the "JOA") where the financing would have been the responsibility of the participant agencies in the financing. This would have been a similar but not identical legal structure to the Washington Public Power Supply System (the "Supply System") such that underlying legal obligations would have been clearly enforceable.

The member agencies of the JOA are listed in Appendix A along with their respective shares. Appendix B lists relevant ratings assigned by Moody's Investors Service, Inc. ("Moody's") and Standard & Poor's Corporation ("S&P") as of July 1995. These ratings are approximately those which were accorded the same entities in 1982 with some revisions. We would note that the top eight member agencies comprise approximately 56.31% of the participating shares and are all currently accorded ratings of "A" or higher from Moody's and S&P. Five of these actually carry current ratings of "A1" or "A+" or higher from at least Moody's or S&P. Five of the 10 non-generators are participants of up to 1% and are currently rated at least "A" by either Moody's or S&P.

All of the member agencies are assumed to have signed "take or pay" agreements, such that each would pay for its proportionate share of the debt service on the financing regardless of whether or not the project produced the expected levels of output. In the event that one participant failed to pay its share of the debt service, each remaining participant would be responsible for an increased level of debt service of up to 125% of the member agency's original commitment. Based on such a generally used financing structure, we have assumed that a financing by a JOA consisting of the assumed member agencies would have received and been able to maintain a rating of "A", or slightly higher, from both Moody's and S&P, the two largest and most respected rating agencies. In the case of the JOA or

7(b)(2) Customer issuing revenue bonds with the advantage of a Bonneville "take or pay" or "capability" power sales contract, we have assumed that the financing would have received and been able to maintain a rating of "AA", from both Moody's and S&P.

No external factors are assumed to impede the operations of the JOA. Such external factors include any referendum concerning the approval of a financing for which a favorable result is assumed. Any legal impediments which may have existed which would restrict the hypothetical financing agency's access to the credit markets (such as the Washington State Supreme Court decision of June 1983 concerning the Supply System) are assumed to have been removed by corrective legislation or favorable judicial decision. Similarly, no external factors are assumed to restrict the financing of resources by 7(b)(2) Customers, non-7(b)(2) customers or other entities in terms of assuming the various hypothetical borrowings made for the purposes of performing the 7(b)(2) test.

In estimating the financing costs for specific resources, such as the Cowlitz Falls Project, we have assumed a rating based upon the particular sponsor's credit rating, assuming no "dry hole" or construction and completion risk. Therefore, the ability of the Public Utility District No. 1 of Lewis County ("Lewis County PUD"), for example, to service its own load with the resource is also assumed in order to meet requirements for investment grade ratings from both Moody's and S&P. Similarly, we would estimate financing costs for other anticipated conservation and generation resource providers, assuming that suitable uses for the resource output were available.

SECTION 5

ASSUMPTIONS CONCERNING RESOURCE ACQUISITIONS

The resource acquisition program undertaken by the JOA is assumed to consist of two phases under a set of assumptions received from Bonneville. The first phase commenced in fiscal year 1981-82 with the assumed acquisition of resources to replace the reserve benefits provided by the DSI load that are not provided in the 7(b)(2) case. Noting that the member agencies would have been required to produce the required replacement reserves in fiscal year 1981-82, Bonneville has assumed the following: that four combined cycle combustion turbines (total of 1,880 megawatts capacity) at a total construction cost of $770 million were installed in fiscal year 1981-82 and were operational by the end of the fiscal year. The further assumption has been made that the equipment was acquired from reputable suppliers and that completion and performance bonds were provided by the suppliers in order to minimize any construction/acquisition risk.

The first phase of the financing program provided for the acquisition of the combustion turbines is assumed to have included the following:

- Revenue bonds of the JOA would have been issued in three series of approximately $900 million in total.

- The revenue bonds would have provided for level payments of debt service and incorporated a standard structure of serial and term bonds.

- The revenue bonds would have received ratings of "A" from both Moody's and S&P if they were backed solely by the take-or-pay obligations discussed above, and "Aa/AA" had they been backed by an obligation of Bonneville.

- The revenue bonds would be advance refunded in a single issue of refunding bonds in 1997 in order to take advantage of lower projected borrowing rates.

The financing of the resource acquisition program associated with the DSI reserves is assumed to have originally occurred in 1982. Based upon forecasted Bonneville borrowing rates, an assumed tax-exempt borrowing rate of 6.23% with Bonneville' s backing is used for the 7(b)(2) test. A borrowing differential of 14 basis points is assumed (or 6.37%) in the Program Case without Bonneville backing. The basis for the 14 basis point differential is explained in Section 10. (Note: We understand that an 11 basis point differential is assumed in Bonneville' s 1996 Initial Rate Proposal. Due to timing issues with the availability of the report, we understand that a clarifying change to the 7(b)(2) Study will be made as part of Bonneville' s Supplemental and Final Rate Proposal in order to reflect the 14 basis points differential calculated in this report).

The second phase of the resource acquisition program involves the resources listed in Appendix C. We would note that these resources consist of the acquisition of individual projects involving conservation resource and generation resource programs sponsored by 7(b)(2) Customers as well as a variety of other sponsors. As part of its resource acquisition programs, Bonneville has solicited resources through its Competitive Resource Acquisition Program, unsolicited proposals, BPA Billing Credits Policy, and other programs.

The City of Idaho Falls entered into a Power Purchase Agreement dated April 1, 1982 with Bonneville for the purchase of all power and energy produced from three hydroelectric generating plants operated by the City of Idaho Falls (the "Idaho Falls Project"). The Public Utility District No. 1 of Lewis County entered into a Power Purchase Agreement dated May 23, 1991 with Bonneville for the output of the Cowlitz Falls Hydroelectric Project (the "Cowlitz Falls Project"). The Northern Wasco County People's Utility District entered into a Power Purchase Agreement dated August 27, 1993 with Bonneville for the output of the McNary Dam Fishway Hydroelectric Project (the "McNary Fishway Project.) Recently, under the terms of a Settlement and Termination Agreement, Bonneville and the Northern Wasco County's Public Utility District have agreed to a cessation of construction of the McNary Fishway Project with Bonneville committing to continue to pay debt service on the revenue bonds issued to finance the McNary Fishway Project.

Bonneville has solicited for resources through the BPA Billing Credits Policy contained in Section 6(h) of the Act and the Competitive Resource Acquisition Program, which includes the Resource Contingency Program. Under the BPA Billing Credits Policy, Bonneville has contracted for the output of 3 projects consisting of South Fork Tolt, Wynocchee and Short Mountain Landfill which aggregate 10.7 average megawatts. Under the terms of the BPA Billing Credits Policy, Bonneville's obligation to purchase the output is subject to the availability of the resource and, therefore, we do not believe the existence of the Bonneville power purchase agreement to be material to the credit rating of the financing associated with the resource.

In general, the hypothetical financing agency consisting of the 7(b)(2) Customers would apportion the risks of resource acquisition due to non-completion, technical difficulties or other factors among the member agencies in proportion to their ownership shares. Similarly, individual resource sponsors are assumed to accept such risks without allocation to third parties. Thus, the risks of non-completion or technical difficulties are not assumed to be assessed for the purposes of this study as factors which would impact the financing costs of particular resources.

Financing of the balance of second phase resource acquisitions is assumed to occur through a series of financings in anticipation of cash flow requirements. All financings are assumed to be undertaken at fixed interest rates. The anticipated financings would generally involve level debt service. In the case of the JOA entity issuing revenue bonds, the financing would rank as parity debt with the revenue bonds assumed to have been issued in fiscal year 1981-82. The revenue bonds or project financings issued by, or entered into by, 7(b)(2) Customers, non-7(b)(2) customers or other entities would have comparable features.

Financing of the Cowlitz Falls Project, the Idaho Falls Project, and the McNary Fishway Project is assumed to have occurred at the time when the sponsors of each of the projects issued revenue bonds to provide for the capital costs of each respective resource. Resources to be acquired from non-7(b)(2) Customers are assumed to be acquired on a project finance basis wherein Bonneville would contract to purchase power output in the Program Case or with the resource contracted with the JOA in the 7(b)(2) study.

In addition, where available, it is assumed that all financings are structured to take full advantage of tax-exempt financing, subject to the provisions of applicable tax law. Also, we would note that Section 9 (f) of the Act requires certain certifications by the Administrator prior to the acquisition of resources which must be met in order that the exemption from gross income in Section 103(a)1 of the Internal Revenue Code of 1986 be achieved. As a result, the assumption is made for the purposes of the resource acquisitions contemplated with Bonneville that the tax-exemption for financings, where available, will not be adversely affected and that Bonneville will be able to provide the certifications required under the Act.

We would also note that the assumed credit ratings on revenue bonds involving an obligation of Bonneville have remained stable in spite of recent events. Drought conditions, the financial requirements of Bonneville's resource acquisition programs, fish and wildlife issues and the planned closing of the Trojan Nuclear Power Project are significant issues affecting the Pacific Northwest and Bonneville's credit ratings. However, for the purposes of the 7(b)(2) rate test, no change in credit ratings is projected for Bonneville, or the 7(b)(2) Customers, as it pertains to the financing feasibility of particular resources financed with debt issued in the public credit markets.

SECTION 6

IDAHO FALLS PROJECT

On April 1, 1982, the City of Idaho Falls, Idaho executed a Power Purchase Agreement whereby Bonneville agreed to a long-term purchase of the output of three hydroelectric generating plants to be constructed in the service territory of the City of Idaho Falls. The City of Idaho Falls provided for the capital costs of constructing the three hydroelectric generating plants with the proceeds of revenue bonds issued in 1981 (the "1981 Bonds"). The 1981 Bonds were advance refunded in 1985 and were the subject of an additional refunding and restructuring completed in 1991. The City of Idaho Falls has also recently completed an additional restructuring of its debt on a taxable interest rate basis.

Under the terms of the Power Purchase Agreement with the City of Idaho Falls, the City may deliver to Bonneville a notice of withdrawal of the total project generation effective no earlier than three years from the year in which such notice is given, but not before July 1, 1988 or after July 1, 1998. Because the revenues of the City's Electric System (as defined) secure the City of Idaho Falls revenue bonds issued to finance the Project, we do not believe the existence of the Bonneville Power Purchase Agreement to be material to the credit rating of these bonds. Therefore, the cost of the Idaho Falls Project resource would not change as a result of the financing assumptions required by the 7(b)(2) rate test.

SECTION 7

COWLITZ FALLS PROJECT

On May 23, 1991, the Public Utility District No. 1 of Lewis County, Washington ("Lewis") entered into an Amendatory Contract for Power Purchase (the "Contract") whereby Bonneville agreed to enter into a long-term purchase of the output of a hydroelectric generating plant known as the Cowlitz Falls Project ("Cowlitz Falls Project"). Bonneville and Lewis agreed that Lewis would finance construction of the Project through the issuance of revenue bonds with Bonneville agreeing to pay to or on behalf of Lewis amounts equal to Project Power Costs (as defined) including Annual Debt Service (as defined) on such revenue bonds for the life of the Contract. On August 27, 1991, Lewis issued $171,095,000 in Public Utility District No. 1 of Lewis County, Washington Cowlitz Falls Hydroelectric Project Revenue Bonds, Series 1991 (the "Bonds"). The Bonds were rated Aa/AA with annual debt service payments of approximately $13,465,000 and a final maturity of October 1, 2024. More recently, the callable Bonds were advance refunded on August 23, 1993 which lowered their approximate annual debt service to $13,050,000.

Under the terms of the Contract, the primary source of security for the Bonds is revenues received from BPA pursuant to the Contract and a Payment Agreement (the "Payment Agreement"). Under the Contract, Bonneville is obligated to pay all project costs, including debt service, whether or not the project is completed or power is delivered. If Bonneville does not make payment under the Contract, it is obligated to pay debt service under the Payment Agreement directly to the bond trustee. Debt Service on the Bonds is an operating and maintenance expense of Bonneville, having priority over payments of Bonneville's Treasury debt and repayment of the Federal investment in the Columbia River power system.

Because the revenues from the Contract and the Payment Agreement secure Lewis' revenue bonds issued to finance the Project, we believe that the Contract and Payment Agreement are the only means that qualify the Bonds for their current credit ratings. In fact, early attempts to provide financing for the Project on a basis where construction, performance and environmental risks were apportioned amongst the lenders and vendors for the Project were not successful. Bonneville thus retains the "dry hole risk" for the Project and is obligated to pay debt service on the Bonds for their full term whether the Project is operating or not. For the purposes of the 7(b)(2) test, Lewis is assumed to accept the "dry hole risk" and that the Cowlitz Falls Project output would be dedicated to serving Lewis' own load.

The original bonds were priced on Tuesday, August 27, 1991 with a True Interest Cost of 7.10% The refunding Bonds were priced on Tuesday, August 23, 1993 with a True Interest Cost of 5.61%. As of the close of business on that date, the 30 Year Treasury Bond was at an 6.19% yield and the Bond Buyer 25 Revenue Bond Index as of the close of business August 19, 1993, the date of compilation closest to the date of sale was 5.61%. The 2022 maturity for the Bonds was priced at a 5.5% coupon at a dollar price of 99.871% with a yield of 5.65%. which yield exceeded the yield on the Bond Buyer 25 Revenue Bond Index by 4 basis points. Revenue bonds issued on the same day by the Pilchuck

Development Public Corporation in the State of Washington with a Baa1/BBB yield subject to alternative minimum tax carried a yield of 6% in 2023. No other comparable primary market revenue bond sales by A/A rated or JOA issuers occurred at the same point in time as the sale of the Bonds. Two issues were priced by South Carolina State Public Service (A1/A+/A+) and New York State Power Authority (Aa/AA-) at yields generally lower than the Lewis bonds. However, as these bond issues were sized at $631 million and $1,133 million, respectively, which creates additional demand from term bond buyers as well as the issuers' locations in specialty tax states with high personal income taxes, we do not view them as suitable comparable issuers.

In our opinion, we believe that the borrowing advantage to the 7(b)(2) Customers to consist of 24 basis points between an assumed revenue bond issued with and without a Bonneville contract for the Cowlitz Falls Project. This 24 basis point differential approximates the difference in borrowing yields between the Aa/AA rated Bonds and an A rated obligation based upon the Baa1/BBB rated revenue bond issue which sold at the same time as the Lewis Bonds, as adjusted for the decrease in yield for the alternative minimum tax effect on the same sale date for the Bonds.

SECTION 8

MCNARY DAM FISHWAY PROJECT

On August 27, 1993, the Northern Wasco County People' s Utility District, Wasco County, Oregon ("Wasco") entered into a Power Purchase Agreement (the "Wasco Contract") with Bonneville of the output of a hydroelectric generating plant to be installed in the existing fish ladder at the McNary Dam ("McNary Dam Fishway Project"). Bonneville and Wasco agreed that Wasco would finance construction of the McNary Dam Fishway Project through the issuance of revenue bonds with Bonneville agreeing to pay for on behalf of Wasco amounts equal to the Bonneville Payments (as defined) including Annual Debt Service (as defined) on such revenue bonds for a term of thirty years after the Commercial Operation Date (as defined.) On December 13, 1993, Wasco issued $32,740,000 in Northern Wasco County People' s Utility District, Wasco County, Oregon, McNary Dam Fishway Hydroelectric Project Revenue Bonds, Series 1993 (the "Wasco Bonds".) The Wasco Bonds were rated Aa/AA with annual debt service of approximately $2,225,000 and a final maturity of December 1, 2024.

Under the terms of the contract with Wasco, the primary source of revenue for the Wasco Bonds is revenues received from Bonneville pursuant to the Wasco Contract. Under the Wasco Contract, Bonneville is obligated to pay all project costs, including debt service, whether or not the project is completed, terminated, operating or operable. Bonneville is obligated to make payment under the Wasco Contract directly to the Trustee. Payments under the Wasco Contract are equal in priority to the Cowlitz Contract and are an operating and maintenance expense of Bonneville, having priority over payments of Bonneville' s Treasury debt and repayment of the Federal investment in the Columbia River power system. Recently, under the terms of a Settlement and Termination Agreement, Bonneville and the Northern Wasco County' s Public Utility District agreed to a cessation of construction of the McNary Fishway Project with Bonneville committing to continue to pay debt service on the revenue bonds issued to finance the McNary Fishway Project.

Because the revenues from the Wasco Contract secure the Wasco revenue bonds issued to finance the McNary Dam Fishway Project, we believe that the Wasco Contract is the only means that qualify the Bonds for their current credit ratings. Bonneville thus retains the "dry hole risk" for the McNary Dam Fishway Project and is obligated to pay debt service on the Wasco Bonds for their full term whether the McNary Dam Fishway Project is operating or not. For the purposes of the 7(b)(2) test, Wasco is assumed to accept the "dry hole risk" and that the McNary Dam Fishway Project output would be dedicated to serving Wasco' s own load.

The Wasco Bonds were priced on Monday, December 13, 1993 with a True Interest Cost of 5.357%. As of the close of business on that date, the 30 Year Treasury Bond was at a 6.23% yield and the Bond Buyer 25 Revenue Bond Index as of the close of business December 9, 1993, the date of compilation closest to the date of sale was 5.53%. The 2024 maturity for the Wasco Bonds was priced at a 5.20% coupon at a dollar price of 97.74% with a yield of 5.35% which yield was lower than the

Bond Buyer 25 Revenue Bond Index by 18 basis points. Power revenue bonds issued on the same day by a Florida utility with a Baa1/BBB rating carried a yield of 5.93% in 2022 and were subject to alternative minimum tax. Two issues were priced by Clark County Public Utility District No. 1 and the Municipal Electric Authority of Georgia, both of which carried bond insurance, at yields slightly lower than the Wasco Bonds. No comparable primary market revenue bond sales by A/A rated or JOA issuers occurred at the same point in time as the sale of the Wasco Bonds.

In our opinion, we believe that the borrowing advantage to the 7(b)(2) Customers to consist of 15 basis points between an assumed revenue bond issued with and without a Bonneville contract for the McNary Dam Fishway Project. This 15 basis point differential approximates the difference in borrowing yields between the Aa/AA rated Wasco Bonds and a Baa1/BBB revenue bond issue sold on the same sale date as the Wasco Bonds.

SECTION 9

NON-7(b)(2) CUSTOMER RESOURCES

Private developers, industrial companies, utility subsidiaries, governmental and quasi-governmental entities all represent viable sponsors for developing power projects, though each presents specific regulatory, financing and operating issues which need to be addressed. A given project sponsor's level of experience and demonstrated success are strong indicators for the viability of an operator. Financing vehicles available to project sponsors will be either recourse, where the sponsor's balance sheet is relied upon for credit support, or non-recourse. In a non-recourse project financing, the strength of the project, not the strength of the sponsor, provides the support for the debt. Project financings would derive incremental benefits from inclusion of a Bonneville power purchase contract.

For the purposes of this analysis, it is assumed that Bonneville would enter into an all encompassing power purchase agreement whereby Bonneville would be obligated to pay on a basis where a pricing mechanism would cover a project's fixed and variable costs. As a result, the project's financing should be indifferent to the level of electricity actually purchased. Other factors including power delivery requirements, security deposits, performance criteria, regulatory out provisions, milestone criteria, force majeure events, security interests, events of default and remedies upon default are presumed to be resolved in a fashion which enables a project to be financed upon standard commercial terms.

Project sponsors which are private entities may or may not be able to qualify for tax exempt financing for a particular project and generally may do so only where a facility qualifies as an "exempt facility" such as a waste to energy facility. Projects financed with tax-exempt financing would likely occur at interest rates comparable to those for the hypothetical JOA discussed in Section 9. Projects financed with private sources of capital would likely be financed with high leverage, which is usually 75 or 80% but can be as much as 100%, which allows for a minimization of equity investment by the project sponsor. We assume that a project financing with a Bonneville contract would provide the means for securing debt financing at pricing which would be at the upper end of the quality range for similar projects. The perceived credit quality of the Bonneville contract obligation among potential financing sources would increase financing options for a given project.

Private financing costs for generating projects undertaken by private sponsors will vary from transaction to transaction based upon project economics and other factors. However, we believe that private financing for a project with a Bonneville contract could be arranged at 50 basis points over the lender's cost of funds which is assumed for the purpose of the 7(b)(2) rate test to be six month's London Interbank Offered Rate ("LIBOR") with 100% financing of project costs. Without a Bonneville contract, and assuming the JOA issuing entity, borrowing rates would be equivalent to those for the hypothetical JOA discussed in Section 12. Appendix D includes a fourteen year history of monthly averages for 6 month LIBOR along with the calculated borrowing rates for the same period. These rates have not been adjusted for the possible effects of entering into interest rate swaps or conversion agreements which could have the effect of fixing the interest rates on all or a portion of a financing for a period of time or the remaining term to maturity for the transaction.

However, in order to adjust the variable LIBOR interest rates to an estimated fixed interest rate for comparison purposes, we have assumed a 50 basis point addition to the LIBOR based interest rates to represent the amortized cost of an interest rate swap. The assumed interest rate differential between the taxable interest rate for the resource acquired from a non-7(b)(2) customer and the hypothetical JOA is negative forty-seven (-47) basis points. This result is reached by examining average historic borrowing spreads over a fourteen year period.

SECTION 10

JOA BORROWING COSTS

Appendix D lists all competitive and negotiated bond issues for public power agencies over $50 million for the period from January 1, 1982 to June, 1995. One of the largest issuers throughout this period has been the Washington Public Power Supply System (the "Supply System") which completed the advance refunding of high coupon net billed revenue bonds previously issued during the high interest environment of the early 1980's. Appendix D compares the true interest cost for each financing for each fiscal year to the Bond Buyer 25-Bond Revenue Bond Index ("Revenue Bond Index"). The Revenue Bond Index consists of revenue bonds maturing in 30 years where 11 of the 25 bonds included in the index are electric power related financings. We would note that the Supply System was added to the Revenue Bond Index effective September 27, 1990. In general, the Revenue Bond Index consists of issuers with a rating of "A" or higher with a concentration of issuers rated "A1" or "AA" from at least one rating agency.

For the purposes of analyzing the anticipated correlation between ratings and borrowing costs, we have further segregated the power bond issues on a fiscal year basis in Appendix D between those which carry ratings of at least "AAA" (Appendix D-1), "AA" (Appendix D-2) and "A" (Appendix D-4) from either Moody's or S&P. Also, we have eliminated the Supply System from the list of power revenue bond issuers with at least "AA" from either rating agency (Appendix D-3) in order to assess the effect that the heavy recent issuance of refunding revenue bonds by the Supply System may have had versus other less frequent issuers. The average true interest borrowing cost as a percentage of the Revenue Bond Index for each fiscal year is summarized in Appendix E both with the Supply System included as well as with the Supply System excluded.

Appendix D-4 indicates that the issuance of revenue bonds by the "A" rated joint operating agency power bond issuers occurred at the percentage spreads to the Revenue Bond Index as summarized in Appendix E. Appendix E shows that, in our opinion, borrowings by the JOA with an assumed rating of "A" could reasonably be expected to occur at interest rates approximating a similar spread to the Revenue Bond Index. The actual percentage spreads of the Revenue Bond Index for joint operating agency power revenue bonds issued with "AA" or "AAA" ratings are also summarized in Appendix E.

The effect of the heavy issuance of refunding revenue bonds by the Supply System is similar to the phenomenon which occurred during the early 1980's when the Supply System issued the revenue bonds which were most recently refunded. During a period of heavy new issue supply by a single issuer, the interest rates on subsequent borrowings tend to increase both relative to the general market and to other comparably rated issuers with less active financing programs. However, in our opinion, the true borrowing costs of the JOA would more reasonably be expected to occur at or near the historic spread relationship to the Revenue Bond Index as long as multiple issues were separated by sufficient time in order not to create an oversupply of the same issuers' bonds in the credit markets.

The evaluation of the factors noted above leads to the conclusion that the costs of a future borrowing backed by a Bonneville resource acquisition contract could reasonably be expected to approximate the average of those achieved over the fourteen year period shown in Appendix D-3. In other words, Bonneville could achieve an interest rate differential of approximately 14 basis points on future borrowings as compared to the hypothetical "A" rated JOA to acquire the resources shown in Appendix C. This basis point differential was arrived at by calculating the interest rate spread differences between the "AA" power revenue bond issuers (excluding the Supply System) and the "A" power revenue bond issuers over the most recent fourteen fiscal year period. We have summarized below the relevant Revenue Bond Index averages for fiscal years 1981-82 to 1994-95 along with the assumed and anticipated borrowing rates.

BOND BUYER REVENUE BOND INDEX,
ASSUMED BORROWING RATES AND
ANTICIPATED BORROWING RATES

Fiscal Year Averages

Fiscal Year	Index
1981-82	13.250%
1982-83	10.130%
1983-84	10.434%
1984-85	9.900%
1985-86	8.257%
1986-87	7.678%
1987-88	8.402%
1988-89	7.165%
1989-90	7.506%
1990-91	7.197%
1991-92	6.690%
1992-93	6.058%
1993-94	6.078%
1994-95	6.574%
Average 1981-82 to 1994-95	8.387%

Assumed Borrowing Rates

Fiscal Year	Bonneville	JOA	Difference
1981-82	12.65%	13.31%	.66%
1982-83	9.86%	10.47%	.60%
1983-84	10.68%	10.74%	.05%
1984-85	10.35%	10.10%	(0.25)%
1985-86	8.49%	8.42%	(0.07)%
1986-87	7.77%	7.68%	(0.09)%
1987-88	8.50%	8.48%	(0.02)%
1988-89	7.01%	7.12%	0.11%
1989-90	N/A	7.49%	N/A
1990-91	6.96%	7.02%	.06%
1991-92	6.33%	6.34%	.02%
1992-93	5.73%	5.81%	.08%
1993-94	5.63%	5.98%	.35%
1994-95	6.37%	N/A	N/A

	BONNEVILLE		JOA		
Fiscal Year Average	% of Index (1)	Rate (2)	% of Index (1)	Rate (2)	Basis Point Difference
1981-82 to 1994-95	98.33%	8.2247%	99.82%	8.3719%	14.72

N/A = Not Available.

(1) Based upon relevant spreads for "AA" and "A" power revenue bond issuers versus Bond Buyer 25 Revenue Bond Index (the "Index").

(2) Calculated by applying the percentage of the Index to the average of the Index for the period 1981-82 to 1994-95 (8.387%).

In our opinion, the above assumed borrowing rates are reasonable estimates based upon the actual borrowing costs shown in Appendices D-1 through D-4. Many factors influence the movement of tax-exempt interest rates and the relationships between borrowing rates for differently rated securities. Among these factors are: the timing of particular financings; the absolute levels of interest rates; the perceived credit quality of particular issuers; the overall supply and demand for tax-exempt and taxable securities. If any of these factors were to change over time, then historical interest rate spread relationships could increase or decrease which would change the assumed borrowing interest rate differentials calculated above. However, we believe the indicated basis point differential to represent a reasonable estimate upon which to base the portion of the 7(b)(2) test involving the hypothetical JOA.

We would note that the assumed borrowing rates as well as borrowing rate spreads shown above for fiscal years 1981-82 through 1983-84 are greater than for subsequent years mainly due to the events surrounding the Supply System default. An assessment of the combined effects on the borrowing costs of the hypothetical JOA due to the Supply System default and the heavy volume of issuance of power revenue bonds during the early 1980's is necessarily subjective. The effects of the default and concerns about credit quality issues regarding all joint operating agencies, as well as Bonneville, would have increased borrowing costs for the hypothetical JOA. More recently, while the effects of the default have lessened as evidenced by the ability of the Supply System and other JOA issuers to finance at historically attractive interest rate levels and spreads, new concerns have arisen about the competitiveness of electric utilities, including wholesale utilities such as Bonneville, to compete in a more competitive environment.

APPENDIX A

PARTICIPATION IN HYPOTHETICAL PUBLIC FINANCING ENTITY

PARTICIPANT	% SHARE
Eugene Water and Electric Board	4.07
Seattle	16.42
Tacoma	10.06
PUD #1 of Chelan County	5.29
PUD #1 of Cowlitz County	7.57
PUD #1 of Douglas County	1.04
PUD #2 of Grant County	3.05
PUD #1 of Snohomish County	8.81
SUBTOTAL - GENERATORS (8)	56.31
Port Angeles	1.29
Springfield	1.30
PUD #1 of Benton County	2.46
Central Lincoln PUD	2.48
PUD #1 of Clark County	4.68
Clatskanie PUD	1.45
Franklin PUD	1.06
PUD #1 of Grays Harbor County	2.36
PUD #1 of Lewis County	1.17
Umatilla Electric Cooperative Association	1.14
SUBTOTAL - NONGENERATORS WITH A GREATER THAN 1% SHARE (10)	19.39
SUBTOTAL - REMAINING NONGENERATORS (99)	24.30
TOTAL (117)	100.00

APPENDIX B

RATINGS FOR
PARTICIPANTS IN HYPOTHETICAL PUBLIC FINANCING ENTITY

PARTICIPANT	MOODY'S	S&P
Eugene Water and Electric Board	Aa	AA
Seattle	Aa	AA
Tacoma	A1	A+
PUD #1 of Chelan County	A1	A+
PUD #1 of Cowlitz County	A	A-
PUD #1 of Douglas County	A1	A+
PUD #2 of Grant County	Aa	A+
PUD #1 of Snohomish County	A1	A
Port Angeles	--(2)	A
Springfield	A	A
PUD #1 of Benton County	--(1)	--(1)
Central Lincoln PUD	A	A+
PUD #1 of Clark County	--(2)	--(2)
Clatskanie PUD	--(2)	--(2)
Franklin PUD	--(1)	--(1)
PUD #1 of Grays Harbor County	--(1)	A(3)
PUD #1 of Lewis County	Aa(4)	AA(4)
Umatilla Electric Cooperative Association	--(2)	--(2)

(1) No Non-bond insured electric revenue debt outstanding.
(2) No rated electric revenue debt outstanding.
(3) Rating prior to defeasance. No other non-bond insured electric revenue debt outstanding.
(4) Rating for Cowlitz Falls Project backed by Bonneville Power Purchase Agreement and Payment Agreement.

APPENDIX C

HISTORIC AND ANTICIPATED FUTURE RESOURCE ACQUISITIONS (1

(000's Omitted)

CONSERVATION

Fiscal Year	New Investments	Expense	Total
1981-82	$ 52,485	$ 0	$ 52,485
1982-83	168,498	3,912	172,410
1983-84	52,692	11,139	63,831
1984-85	78,692	16,747	95,438
1985-86	72,198	2,482	74,680
1986-87	47,305	7,781	55,086
1987-88	36,178	12,122	48,300
1988-89	27,542	12,172	39,714
1989-90	25,234	15,102	40,330
1990-91	31,384	16,513	47,896
1991-92	44,062	26,098	70,159
1992-93	56,563	27,719	84,282
1993-94	64,286	30,445	94,732
1994-95	69,445	32,804	102,249
1995-96	29,753	26,940	56,693
1996-97	13,000	22,209	35,209
1997-98	6,840	25,363	32,203
1998-99	3,874	24,624	28,498
1999-00	954	18,321	19,275
2000-01	74	17,068	17,141
2001-02	0	16,197	16,197
2002-03	8	14,343	14,351
2003-04	8	14,086	14,095
2004-05	8	13,815	13,023

Other Acquisitions

Fiscal Year	Billing Credits Generation And Other	Competitive Acquisition Generation	Idaho Falls/ Cowlitz Falls	Geothermal	Wind Demo	C
1997	3,517	5,519	12,510	0	3,913	
1998	3,394	5,446	11,091	0	3,615	
1999	3,254	5,365	10,297	0	3,421	
2000	3,119	5,282	10,014	0	3,263	
2001	2,974	5,193	9,756	0	3,154	
2002	3,267	5,108	9,442	0	3,020	
2003	3,268	4,985	8,839	0	2,900	
2004	3,272	4,857	8,596	0	2,815	
2005	3,178	4,755	8,373	0	2,748	

(1) All amounts shown are in 1979-80 dollars.
Source: Bonneville Power Administration.

APPENDIX D

HISTORIC AND ANTICIPATED FUTURE BORROWING COSTS
NON-7(b)(2) CUSTOMER RESOURCES

Assumed Historic Project Financing

		Bonneville		JOA	JOA Di
Fiscal Year	6-Month LIBOR(1)	Average Variable Rate	Average Fixed Rate(2)		Average Variable Rat
1981-82	15.41%	15.91%	16.41%	13.31%	(2.60)%
1982-83	10.29	10.79	11.29	10.47	(0.32)
1983-84	11.17	11.77	12.27	10.74	(1.03)
1984-85	9.57	10.07	10.57	10.10	.03
1985-86	7.65	8.15	8.65	8.42	.27
1986-87	6.55	7.05	7.55	7.68	.63
1987-88	7.67	8.17	8.67	8.48	.31
1988-89	9.32	9.88	10.38	7.12	(2.76)
1989-90	8.27	8.77	9.27	7.49	(1.28)
1990-91	6.85	7.35	7.85	7.02	.33
1991-92	4.20	4.72	5.22	6.35	1.65
1992-93	3.41	3.91	4.41	5.81	1.90
1993-94	4.29	4.79	5.29	5.98	1.19
1994-95	4.98	5.48	5.98	N/A	N/A

(1) London Interbank Offering Rate.
(2) Includes amortized cost of interest rate swap assumed to be 50 basis points.

Assumed Project Financing

Fiscal Year Average	**Bonneville** Average Variable Rate	Average Fixed Rate(2)	**JOA**	**JOA Di** Average Variable Rat
1981-82 to 1994-95	8.34%	8.84%	8.37%	(0.03)%

APPENDIX E

HISTORIC BORROWING SPREADS

FISCAL YEAR AVERAGES BBI REV DEX AS %

Fiscal Year	A	AA	AA(ex/$$)	AAA
1981-82	100.46%	102.16%	95.46%	109.84%
1982-83	103.32%	97.36%	97.36%	N/A
1983-84	102.89%	102.41%	102.41%	N/A
1984-85	102.02%	104.59%	104.59%	97.85%
1985-86	101.98%	102.82%	102.82%	86.23%
1986-87	100.04%	101.21%	101.21%	100.41%
1987-88	100.92%	101.12%	101.12%	97.95%
1988-89	99.45%	98.53%	97.81%	97.50%
1989-90	99.75%	101.49%	N/A	94.33%
1990-91	97.56%	100.54%	96.67%	97.40%
1991-92	94.97%	96.46%	94.63%	94.38%
1992-93	95.88%	94.64%	94.64%	97.01%
1993-94	98.37%	93.76%	92.68%	96.13%
1994-95	N/A	96.88%	96.88%	99.52%
Averages For:				
1981-82 to 1994-95	99.82%	99.57%	98.33%	97.38%

ANTICIPATED BORROWING RATES | CHA

Fiscal Year	BBI	BPA AA(ex/$$)	AA	A	A to AA
1981-82	13.250	12.65	13.54	13.31	-0.23
1982-83	10.130	9.86	9.86	10.47	0.60
1983-84	10.434	10.69	10.69	10.74	0.05
1984-85	9.900	10.35	10.35	10.10	-0.25
1985-86	8.257	8.49	8.49	8.42	-0.07
1986-87	7.678	7.77	7.77	7.68	-0.09
1987-88	8.402	8.50	8.50	8.48	-0.02
1988-89	7.165	7.01	7.06	7.13	0.07
1989-90	7.506	0.00	7.62	7.49	-0.13
1990-91	7.197	6.96	7.24	7.02	-0.21
1991-92	6.690	6.33	6.45	6.35	-0.10
1992-93	6.058	5.73	5.73	5.81	0.08
1993-94	6.078	5.63	5.70	5.98	0.28
1994-95	6.574	6.37	6.37	N/A	N/A