Stenehjem,Carlene R - DKC-7

From: on behalf of BPA Public Involvement

Subject: FW: JOINT COMMENTS OF THE IDAHO ENERGY AUTHORITY & THE IDAHO CONSUMER-OWNED UTILITIES ASSOCIATION

Attachments: 10.31.06 IDEA-ICUA Joint Regional Dialogue Comments - Final.pdf; EXHIBIT 1.pdf; EXHIBIT 2.pdf; EXHIBIT 3.pdf; Exhibit 4 tables.pdf; Signature Page.pdf

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From: Nina **Sent:** Tuesday, October 31, 2006 9:18 AM
To: BPA Public Involvement
Cc: Peter J. Richardson (E-mail)
Subject: JOINT COMMENTS OF THE IDAHO ENERGY AUTHORITY & THE IDAHO CONSUMER-OWNED UTILITIES ASSOCIATION

PLEASE FILE THE ATTACHED.

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Idaho Energy Authority IDEA

IDAHO CONSUMER-OWNED UTILITIES ASSOCIATION

BEFORE THE U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

IN THE MATTER OF THE BONNEVILLE POWER ADMINISTRATION'S LONG TERM REGIONAL DIALOGUE POLICY PROPOSAL	)))))))	JOINT COMMENTS of the IDAHO ENERGY AUTHORITY, INC. and the IDAHO CONSUMER-OWNED UTILITIES ASSOCIATION, INC.

COMES NOW, the Idaho Energy Authority, Inc. (IDEA), and the Idaho Consumer-Owned Utilities Association, Inc. (ICUA) , pursuant to the Bonneville Power Administration's ("BPA") Long-Term Regional Dialogue Policy Proposal ("Regional Dialogue" or "Proposal") issued on July 13, 2006 and hereby provides its comments as follows:

I.

OVERVIEW AND SCOPE

IDEA is a Joint Action Agency and an Idaho not for profit corporation consisting primarily of wholesale power supply customers of BPA. IDEA's member roster consists of 24 publicly and municipally owned electric utilities located in Washington, Idaho, Montana, Wyoming and Nevada. ICUA is an Idaho non-profit corporation representing twenty-one municipal and cooperative utilities that are customers of BPA in Idaho. There is significant overlap of IDEA and ICUA membership but there are functional differences between IDEA and ICUA. IDEA is generally more actively engaged in regional and operational issues while ICUA tends to focus primarily on state and national policy issues. IDEA's and ICUA's comments are combined in this single document because of the broad sweeping operation and policy impacts of BPA's Regional Dialogue Proposal. A complete list of IDEA/ICUA members is attached as Exhibit 1 hereto.[1] While our comments are thoughtful and as detailed as is possible at this point of the process, we may not have commented on all of the important points in the Policy. Our silence on any specific issue should therefore not be viewed by BPA as either acquiescence or objection.

Overall, IDEA/ICUA supports the basic concept of allocation of the BPA system. We believe that individual utilities ought to have the opportunity to plan for their own load growth and assume responsibility for their resource decisions. At the same time we believe, with the implementation of the Regional Dialogue, BPA should not assume that its obligations to provide "Tier 1" service has been mitigated in any manner. We believe that Tier 1 service includes <u>delivery</u> of power and energy regardless of the physical interconnection between BPA and its customers.

These comments are organized according to the appearance of the issue in the Regional Dialogue and are not necessarily organized in priority of importance.

[1] Fur purposes of "counting" comments IDEA and ICUA ask that these comments be attributable to each of the member utilities listed on Exhibit A.

II.

RELATIONSHIP TO PRESIDENT'S BUDGET PROPOSAL

Bonneville provides that it will "use any surplus power sales (net secondary) revenues it earns in any given year above its historical high level of $500 million to make early payments on its Federal bond debt to the U.S. Treasury". P. 6. BPA is able to generate secondary revenues using the system for which BPA's customers have paid. Therefore secondary revenues should not be "hard wired" to make prepayments to Treasury of Bonneville debt. Secondary revenues should be used first and foremost to reduce Bonneville's wholesale Tier 1 rates. Bonneville should retain the flexibility to pre-pay its Treasury debt, but only when doing so makes sound fiscal sense.

III

CONSERVATION AND HIGH WATER MARK

The Proposal, at pages 14 – 15, provides:

> BPA proposes to add the amount of conservation achieved by each utility from FY 2007 through FY 2010 to its individual HWM …. For this purpose BPA proposes to count 100 percent of self-funded megawatts and 50 percent of BPA-funded megawatts.

IDEA/ICUA believes the fifty percent limitation on BPA-funded conservation for purposes of calculating an individual utility's "High Water Mark" ("HWM") may be sufficient to maintain an incentive for continued utility participation in BPA-funded conservation programs. We are open to increasing that number should it prove necessary in order to maintain the utility incentive to participate.

We also agree with the Proposal to "count 100 percent of self-funded megawatts" acquired through conservation efforts as not reducing a utility's HWM. We hope, however, that BPA will also include in the definition of "self-funded megawatts" those conservation efforts engaged in by third-party vendors and/or self-funded conservation acquired by industrial customers and other large discreet consumers. Some utilities have third party, for profit, conservation providers operating in their service territories and some utilities have large industrial facilities that are actively engaged in conservation on their own. These activities ought to be included in the definition of what conservation measures are "self-funded". To do otherwise may cause some utilities to discourage such third party conservation activities until after the HWM has been calculated.

At page 56 of the Regional Dialogue BPA states, "BPA proposes recovering costs of achieving conservation on the loads it serves in Tier 1 rates." IDEA/ICUA agrees that the costs of conservation aimed at <u>loads it serves in Tier 1</u> should be recovered from Tier 1 customers. Conservation aimed at Tier 2 load, on the other hand, should be paid for by Tier 2 customers/load. It is not clear from the Proposal whether BPA is suggesting that costs associated with Tier 2 conservation efforts would be blended with and recovered from Tier 1 rates. If so, IDEA/ICUA would be opposed to such a blending because it would increase Tier 1 rates and partially frustrate the purpose of tiered rates. Preventing such a blending may present implementation challenges because it may be difficult to identify at which Tier a particular conservation product is aimed. An easy example would be DSM programs targeted at new construction on a utility above its HWM. Those conservation efforts should be allocated to Tier 2 for such a utility. A more challenging test for the same utility would be the allocation of costs for a program that is aimed at customers regardless of the year they come on line. IDEA/ICUA looks forward to working with BPA on these issues. However, the bottom line is that Tier 2 load should be responsible for the costs associated with Tier 2 conservation. To do otherwise inflates Tier 1 costs.

IV.

PRE-1980 HYDROELECTRIC RESOURCES

In what appears to be a very specifically tailored exception to the use of FY 2010 for calculation of the high water mark, BPA proposes, at page 15:

> [O]ne exception to the use of FY 2010 customer and consumer resources listed in Subscription contracts; a customer's hydroelectric resources used prior to 1980 that BPA expects would be returned to a customer by withdrawal from other customers for the post-2011 period.

Several of us own or are involved in small hydro projects or portions of projects and our understanding is that this language does not apply to any of the IDEA or ICUA members that are so involved.

V.

POOLING

BPA proposes to prohibit pooling of high water marks for the following reasons:

> BPA is concerned that pooling would work against the goal of reducing regional conflict and would become administratively burdensome. Pooling would also increase Tier 1 rates, because any gain in value by the select group of customers who pooled would be at the expense of the other customers since it would reduce the amount of secondary power available to market to lower Tier 1 rates and cause a need for greater amounts of augmentation within the 300 aMW cap, than would otherwise be required. P.17.

IDEA/ICUA disagrees with both the foundation and the conclusion in BPA's reasoning to support its decision to not allow pooling. Encouraging customers to work together by pooling their resources and loads actually reduces regional conflict and lends itself to greater regional cooperation. Pooled utilities will operate more efficiently and thereby serve their customers more effectively. In addition, BPA should not implement policies for the purpose of promoting secondary sales at the expense of service to its priority customers at its lowest cost based rates. Therefore, IDEA/ICUA recommends that pooling be permitted.

VI

FLEXIBILITY

We hope that BPA will work with its customers relative to providing more flexibility and options for acquisition of Tier 2 products than is provided for at page 28 under the “Tier 2 Rate Purchase Alternatives.” Energy managers need the ability to change Bonneville Tier 2 products more frequently than every three years. Effective energy management also requires that BPA’s customers have access to seasonal products and the ability to shape when Tier 2 products are brought to our load. For example a utility may want to take all of its Tier 2 product in the four winter months rather than flat over the year. We urge BPA to build such flexibility into its final record of decision.

VII

TRANSFER ISSUES

As a starting point ICUA/IDEA read the Regional Dialogue Transfer Service section as continuing to represent a perspective by Bonneville that transfer services are primarily costs to be controlled. Consequently, most of the Regional Dialogue proposals are for controls or requirements that target transfer service customers from a cost containment perspective. Fundamentally, this is the wrong “view” of transfer service.

IDEA/ICUA would again suggest that a more compelling case can be made that third party transfer service (or General Transfer Agreements ("GTAs")) saves Bonneville and its customers significant money that would have been otherwise spent had BPA constructed facilities to directly connect everyone to BPA transmission system. A comprehensive study commissioned by ICUA concluded that using the transfer facilities of third party utilities to serve GTA load -- instead of constructing transmission lines to directly serve such load -- has saved BPA "at least $1.7 billion (2004 dollars) in capital costs" and provides annual benefits in the range of $87 to $107 million per year. *Final Report General Transfer Agreements Regional Cost – Benefit Study* p. 2, © Patrick McRae Consulting Services LLC July 29, 2004. A copy of the McRae study is attached hereto as Exhibit 2. Consequently, IDEA/ICUA believes this section of the Regional Dialogue proposal should at least acknowledge the cost "savings" role the GTAs have played in allowing BPA to avoid spending several billion dollars more on transmission facilities in the region.

Delivery of Non-Federal Power: Bonneville proposes to wait to implement its new policy on delivery of non-federal power "until service begins under new Regional Dialogue contracts." (p. 63) No justification is given for delaying implementation of this policy, while moving forward to implement other transfer issues "upon finalization of the Regional Dialogue policy." (p. 63). It makes little sense for IDEA/ICUA members to have to pay for pan-caked transfer service for non-BPA power deliveries for a limited window of time up until September 30, 2011, with the transfer service for such purchases then rolled in beginning October 1, 2011. IDEA/ICUA therefore request that this delayed implementation of rolled-in transfer cost treatment of non-federal deliveries be discarded and the policy be implemented "upon finalization of the Regional Dialogue Policy."

On page 68 Bonneville proposes five "eligibility requirements" in order to qualify for delivery of non-federal power at rolled-in rates. Of the 5 requirements only the fifth requirement is appropriate: i.e., "(e) *The third-party transmission service is over facilities equivalent in function and voltage level of the FCRTS Integrated Network Segment.*" The other four requirements are inappropriate, for the reasons discussed below.

> (a) The first requirement – that "*the transfer customer has historically been served under arrangements between BPA and a third party transmission owner*" – is ambiguous and discriminatory. Ambiguity stems from "when" a customer is deemed "historical" versus "new." More importantly, there may be new public power customers that are eventually able to exercise their statutory rights to receive service from Bonneville; even at Tier 2 rates. However, this "historical" requirement could forever preclude such new customers from ever receiving rolled-in transfer service from Bonneville. No substantive justification for this discrimination is offered.
>
> (b) . The second requirement – that "*The transfer customer must use the FCRTS in combination with third-party transmission service*" – would exclude the South Idaho Exchange Utilities from transfer service benefits. The South Idaho Exchange ("SIE") is a creative and cost effective method of delivering PacifiCorp's physical resources to BPA customers located in Eastern Idaho and Western Wyoming/Montana by exchanging a like amount of BPA's physical

resources to serve PacifiCorp's customers in Western Oregon and Washington. This exchange has proved to be financially beneficial for all involved, including Bonneville. (*See* McRae 2004 Cost-Benefit Study) We hope this is just an oversight on BPA's part as the goal for delivery of non-Federal power over third-party systems should not be extinguished simply because deliveries are made over an exchange agreement. IDEA recently sent a Transmission White Paper to Bonneville recommending that BPA make deliveries of non-Federal Power over existing GTA agreements if the customer is able to physically deliver that power to the load control area currently delivering power over a GTA. We urge BPA to incorporate that concept in the Regional Dialogue. A copy of the White Paper is attached and made part of these comments as Exhibit 3. In summary, we believe customers served by an exchange should be given the opportunity to access non-Federal power at the same cost of a GTA.

(c) The third requirement for BPA payment for delivery of non-federal power is that the third party transfer service is "from" the BPA system "to" the transfer customer's native load. For the reasons explained in sub-paragraph (b) above, this requirement would exclude the South Idaho Exchange utilities from eligibility for payment of delivery of non-federal power. Certainly that is not BPA's intent.

(d) The fourth requirement found on page 68 of the Regional Dialogue proposal provides that non-federal power deliveries can only be made to "Points of Delivery on the transfer customer's service territory that existed as of October 1, 1996." This restriction will needlessly complicate deliveries for Bonneville customers who upgrade or construct new substations and/or add new Points of Delivery. In addition, the date appears to be arbitrary with respect to delivery of non-Federal power in the future. IDEA/ICUA urges BPA to strike the restriction on service of non-Federal power over new Points of Delivery that are installed after 1996.

At the bottom of page 68, the Regional Dialogue begins a discussion of caps on the amount (and cost) of non-Federal power deliveries. IDEA/ICUA understands that there may be some risk associated with an open ended commitment for delivery of non-Federal power. The proposed 30 MW or $800,000 annual increment limit, with a 20 year limit of $16 million or 600 MW is arbitrary and should be stricken. Because we were promised equivalent service there should be no cap. This concept is well documented in the ARTS agreement and is fundamental provision of Transfer service.

Transfer Service for Annexed Load: On page 63 BPA states that it does not intend to implement resolution to issues 6 (transfer service to annexed load) "until service begins under new Regional Dialogue contracts." No justification is given for delaying implementation of this policy either, while moving forward to implement other transfer issues "upon finalization of the Regional Dialogue policy." One of ICUA's/IDEA's members – the City of Weiser – is materially and adversely impacted by this apparent arbitrary delay in permitting rolled-in transfer service for the City of Weiser. We see no reason not to do so and actively urge BPA to resolve these issues now, rather than waiting until service begins under the new Regional Dialogue contracts. We endorse the City of Weiser's comments with respect to providing GTA transfer service for new public power entities now rather than waiting until 2012.

VIII

RESIDENTIAL EXCHANGE

Bonneville's proposal to allocate approximately $250 million of financial settlement benefits of the FCRPS to Investor Owned Utilities ("IOU"s) as Residential Exchange ("RE") benefits is a reasonable compromise. In fact, we believe that, based on current market conditions, a range of $200 million to $250 million is more than reasonable. The BPA proposed RE settlement amount is an adjustment downward from the approximately $300 million of exchange benefits [partially] agreed upon for the last rate period, but which settlement amount is currently being litigated [as being too high]. Base on current market conditions – as opposed to conditions occurring during the last settlement in 2000 – the $250 million is a more than generous reflection of a mid-point of the range of possible RE benefit calculations.

Many commentators in Idaho and throughout the region argue that because residential and small farm customers make up such a strong percentage of the customer base[2] that the IOU benefits under the residential exchange program should be increasing over time, especially after adjusting for inflation. Some commentators argue therefore that benefits should now be in the $350 to $390 million range. Antidotal stories have also circulated as to how a $250 million exchange benefit proposal will put IOU small farm customers in Idaho and other locations "out of business" and would cause great hardship for Idaho IOU residential customers. Therefore, in order to better understand the potential impacts in Idaho of the various RE benefit proposals ICUA commissioned

[2] In Idaho, approximately 85 % of the customer base is served by IOUs and not public power utilities.

an economic analysis by Ben Johnson & Associates. The results of that study can be seen as Exhibit 4 to these comments.

The ICUA Retail Rate Analysis: The Exhibit 4 rate impact study looked at Idaho Power's and Pacificorp's (Rocky Mountain Power; hereinafter "RMP") effective revenues per kwh for residential and small farm customers, compared to similar calculations made for Raft River Electric, Fall River Electric and the City of Idaho Falls. For regional comparative purposes all five utilities serve eastern Idaho and are sequentially contiguous. PCA rate adjustments were ignored in order to get to an "apples to apples" revenue/kwh comparison.

Table 1 of Exhibit 4 shows the effective kwh rate for all five utilities for 2005 with IOU rates including the BPA exchange credit.[3] In 2005, with the exchange credit settlement amount at approximately $300 million, Idaho's two southern Idaho IOU's had the two lowest effective rates for both residential and small farm customers. In 2005 RMP's effective irrigation rate was approximately a half cent below the comparable rate of Raft River Electric and a full 1.5 cents lower than irrigation rate of Fall River Electric. Fall River and Raft River continue to have robust and economically viable small farm customers; in spite of the fact that their irrigation rates are either higher or significantly higher than RMP's.

Table 2 of Exhibit 4 assumes a $250 million RE credit settlement amount, and holds all other factors constant. Even with this drop in total dollars spent by BPA on the RE Program, Idaho IOU residential rates remain lower than the three comparative BPA

[3] For example, in 2005 the exchange credit for RMP amounted to approximately 2 cents per kwh.

customers in Idaho, and RMP's irrigation rate is now about equal to Raft River's irrigation rate, but still significantly below Fall River's irrigation rate.

Table 3 represents a $350 million exchange credit in total, with a proportional amount being allocated into Idaho. Under this scenario, RMP experiences a 10% residential rate reduction and a 20% irrigation rate reduction. RMP's irrigation rate now drops to 3.67 cents per kwh. Meanwhile, Raft River's irrigation rate rises to 4.73 cents per kwh and Fall River's irrigation rate rises to 5.85 cents per kwh.

Conclusions: The following conclusions result from the ICUA eastern Idaho residential and small farm rate analysis and from IDEA's/ICUA's review of the Regional Proposal:

a. If equity is a goal, then a $250 million RE amount provides the greatest retail rate "equity" among public versus private utilities in Idaho.

b. Arguments based on equity, a "fair share" of Bonneville or "we serve more customers than you do" in a particular state have nothing to do with BPA's statutorily mandated calculation of exchange benefits for IOU residential and small farm customers.

c. The corollary to conclusion (b) is that the best alternative may be for BPA to implement the RE fall-back position, take RE settlement off-the-table and simply calculate benefits according to the statutory formula; instead of trying to settle the amount.

d. If BPA now estimates the exchange credit range as between zero and $329 million, then $250 as a midpoint is much more to the right than the left side of "mid."

e. As assumed in the ICUA rate analysis, all other factors will <u>not</u> remain constant in the next rate period.

f. The corollary to conclusion (e) above is that it is just as unlikely that a $250 million exchange credit amount will result in a 20% rate increase to RMP irrigation rates in eastern Idaho as a $350 million exchange credit amount will result in a 20% rate decrease.

g. If anyone's irrigation customers are at risk of going out of business, it will be Fall River's and Raft Rivers if the RE credit goes to $350 million.

IX

2010 HIGH WATER MARK DATE

IDEA/ICUA also supports use of the 2010 High Water Mark date for both resources and loads. It will produce viable data for use in calculating the high water marks for BPA's customers.

X.

DSI SERVICE

IDEA/ICUA strongly opposes any service to DSI load from Tier 1 resources or any service to DSI load that would have the effect of increasing Tier 1 rates.

XI

LDD AND IRRIGATION DISCOUNT

IDEA/ICUA appreciates and supports BPA's proposal to continue with the LDD and the irrigation rate mitigation program. Many of our members are directly

EXHIBIT 1

City of Albion
City of Bonners Ferry
City of Burley
Clearwater Power Company
City of Declo
East End Mutual Electric Company
Fall River Rural Electric Cooperative
Farmers Electric Company
City of Heyburn
Idaho County Light & Power
City of Idaho Falls
Inland Power & Light Co.
Kootenai Electric Cooperative
Lost River Electric Cooperative
Lower Valley Energy
City of Minidoka
Northern Lights, Inc.
City of Plummer
Raft River Rural Electric Cooperative
Riverside Electric Company
City of Rupert
Salmon River Electric Cooperative
City of Soda Springs
Southside Electric Lines
United Electric Co-op
Utah Associated Municipal Power Systems
City of Weiser

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FINAL REPORT

GENERAL TRANSFER AGREEMENTS
REGIONAL COST – BENEFIT STUDY ©

by Patrick McRae Consulting Services LLC
July 29, 2004

Commissioned by the Idaho Consumer-Owned Utilities Association

Patrick McRae Consulting Services LLC
1592 Lone Rock Rd, Glide OR 97443

July 29, 2004

Ronald L. Williams
ICUA Executive Director
1015 W. Hays Street
Boise, ID 83702

Re: **Final Report - GTA Regional Cost-Benefit Study**

Dear Ron:

Enclosed please find my Final Report on General Transfer Agreements – Regional Cost-Benefit Study.

This Final Report differs from my March Preliminary Report in two material ways. First, it incorporates the energization dates for significantly more GTA Points of Delivery (PODs). Those additional PODs were provided by the Public Power Council and significantly improve the statistical reliability of the analysis.

Second, the Final Report differs from the Preliminary Report in the discounting of Operation and Maintenance and Administrative and General costs. In my Preliminary Report O&M and A&G costs were treated the same as Interest & Amortization costs and discounted back to the date of energization. Upon further analysis I determined that this was incorrect, because O&M and A&G costs inflate over time while I&A costs do not. This means that roughly half the annual benefits in the Preliminary Report were being inappropriately discounted. My conversations with BPA staff confirms that the Final Report is now more accurate in its treatment of A&G costs than the Preliminary Report. The net result of this one adjustment is that the benefits described herein are substantially larger than in the Preliminary Report.

Executive Summary

- By using GTAs to serve 256 of its Points of Delivery (PODs), BPA has avoided at least $1.7 billion (2004 dollars) in capital costs, making that amount available for other needed transmission investment without additional borrowing. Had there been no GTAs, BPA's borrowing authority would have been used up long ago. To put that into perspective, $1.7 billion is enough capital to construct over 2,000 miles of single circuit 500 KV line.

- Had BPA constructed transmission to serve the 256 PODs, it is estimated that the total annual transmission costs for these facilities (i.e. additional transmission system revenue requirement) would have ranged from $132 million/year to $152 million/year, depending upon assumptions used to estimate rights-of-way costs.

- By utilizing GTAs rather than constructing transmission to serve the 256 PODs, BPA saves from $87 million/year to $107 million/year ($132/$152 million, less GTA annual cost of $45 million). Clearly GTAs have been a very good business decision by BPA for the region.

- The current rate treatment of GTA costs (i.e., recovered through PBL rates) incorrectly treats a surrogate transmission cost as if it were a power generation cost. However rate analysis provided by BPA rates specialists has demonstrated that the inequities resulting from this Rate treatment are not large.

- The preference customers that have been willing to accept power deliveries from GTAs rather than being directly connected to the BPA system have provided the region's other customers a great service. BPA should acknowledge that sacrifice and in return, establish an immutable business policy that guarantees that customers receiving delivery from GTAs are always treated comparably with directly connected customers in quality of service, rates and other matters.

Thank you for the opportunity to provide this information, and to again work on an issue of concern to ICUA and of such significance to the region.

Sincerely,

/s/ Pat McRae

Patrick McRae

FINAL REPORT

GENERAL TRANSFER AGREEMENTS REGIONAL COST – BENEFIT STUDY ©

by Patrick McRae Consulting Services LLC
July 29, 2004

Commissioned by the Idaho Consumer-Owned Utilities Association

INTRODUCTION

BPA serves Preference Customers in the Northwest at approximately 600 Points of Delivery (PODs). Currently 344 PODs are directly connected to the Bonneville Power Administration (BPA) transmission system, while 256 PODs are served by General Transfer Agreements (GTAs) between BPA and the transferring utility. GTAs make use of 3rd party transmission systems.

Historically GTAs have been utilized because they were less costly than new BPA construction, optimized the use of existing 3rd party transmission and avoided the proliferation of duplicative transmission lines and equipment. Over the years BPA's Customer Service Planning Process has ensured that every GTA was less costly than construction would have been. However, the total benefits that GTAs provide for the region have never been previously computed. This study was commissioned by the Idaho Consumer-Owned Utilities Association (ICUA) to estimate what the BPA construction costs would have been to serve the PODs had GTAs not been utilized to serve this public power load, and thus produce a viable estimate of the regional benefit provided by GTAs.

FINAL RESULTS

By using GTAs to serve BPA's 256 PODs, BPA has avoided at least $1.7 billion (2004 dollars) in capital costs, making that amount available for other needed transmission investment without additional borrowing. If there had been no GTAs BPA's borrowing authority would have been used up long ago. To put that into perspective, $1.7 billion is enough capital to construct over 2,000 miles of single circuit 500 KV line.

Had BPA constructed transmission to serve the 256 PODs, it is estimated that the total annual transmission costs for these facilities, (i.e. additional transmission system revenue requirement) would have ranged between $132 million and $152 million per year, depending on right-of-way costs.

The BPA 2002 GTA Budget (including the costs of the South Idaho Exchange) is $45 million/year. That $45 million/year is the cost of the alternate means of providing transmission to those same 256 PODs. Therefore, it is estimated that the annual benefits

provided to the Northwest by use of GTAs rather than constructing transmission ranges from $87 million/year to $107 million/year.

Note: The fact that the GTA budget appears to be in the range of 30% to 34% of what the annual costs of construction transmission would have been to these PODs seems intuitively correct. This is because with GTAs, BPA is sharing the costs of transmission with the 3rd party owner, and depending upon the specifics of the GTA contract, in some cases can be carrying well less than half the annual costs of the line. It would be unusual for BPA to be carrying much more than half the annual costs of a 3rd party transmission facilities.

METHODOLOGY

Exhibit A -- Construction Cost Estimates

As shown on Exhibit A -- the Cost-Benefit Analysis Spreadsheet -- ICUA located each of the 256 GTA PODs on BPA transmission system maps of the Northwest[1], and measured the line miles "as the crow flies," from each POD to the nearest point on the BPA system. Then, 1999 construction cost estimates provided by BPA were used to determine the costs of building transmission and associated substations to serve each POD. These estimates are conservative because actual line routes are nearly always longer than "as the crow flies." When the nearest BPA source was higher than 115 KV, it was assumed that step down substations would be needed. All new transmission lines were assumed to be 115 KV, Ibis ACSR single pole wood construction, with only 2 exceptions (230 KV for Wells and Harney.)

No costs were included for substation step down transformers and low side breaker facilities at the PODs as it is assumed they would exist regardless of whether the PODs were served by GTA or direct connection to the BPA transmission system.

The BPA construction cost estimates did not include environmental, and indirect overheads, consequently, at the suggestion of BPA, the estimates were increased by 30% to account for these costs. (See Exhibit B.)

The BPA estimates also did not include land and right of way costs. According to BPA sources, a mile of 150-foot right of way is about 18 acres, but because the cost of land varies widely, no useful estimate of cost/acre was available. Again, at the suggestion of BPA, construction costs were increased by 10% and 20% to establish a range for land costs. (See Exhibit B.)

Determining the Annual Costs of Facilities

Annual Cost Ratios are an instrument that is commonly used in the electric utility industry to estimate the annual costs of a facility. These annual costs include categories for Operation and Maintenance, Administrative and General, and Interest and Amortization. Annual

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1 A 30 Page *Bonneville Power Administration Area Office Map, 23 KV and Above*.

Cost Ratios are calculated based on a utility's actual experience with their various types of facilities. When such an Annual Cost Ratio is applied to the estimated capital cost of a facility, the result is an estimate for each the categories of annual costs for that facility. The annual costs for Operation and Maintenance and Administrative and General increase with inflation, therefore BPA 1997-99 Annual Cost Ratios have been used to estimate these costs. The annual costs for Interest and Amortization are based on capital costs in the historical year of construction, therefore it has been necessary to discount the 1999 cost estimates back to that year using the Handy-Whitman Index (See next section). BPA Annual Cost Ratios have varied over the years as would be expected (although the variance was not large). To take this variance into account an average of the 1972 and 1999 BPA Annual Cost Ratios were used in estimating the annual Interest and Amortization costs of BPA facilities that would have served the GTA PODs. (See Exhibit D for detail.) The appropriate Annual Cost Ratios were applied to the construction cost estimates for each GTA POD, to produce the annual costs for that POD. The annual costs for all PODs were then summed to establish the regional annual cost for transmission.

Discounting the Cost Estimates with the Handy-Whitman Index

BPA began establishing GTA PODs in the early 1940's, and continued to establish them through 2001. Because BPA 1999 construction cost estimates were used in this study, it was necessary to discount these construction costs back to the years that the PODs were established in order to determine the interest and amortization portion of the annual costs for each facility. The interest is based on the prevailing rate at the time the facility was constructed. This was accomplished by using "The Handy-Whitman Index of Public Utility Construction Costs," an instrument commonly used for this purpose in the power industry. The energization dates were identified for 118 GTA PODs, or 46% of the total in existence. Energization dates for the remainder could not be determined from either BPA or PPC survey information. Instead the reasonable assumption was made that the distribution of energization dates for the remaining 138 GTA PODs would roughly follow the distribution of the known 118 energization dates. The preliminary report stated that the weighted average Handy-Whitman Index for the 56 PODs energization dates known at the time was 0.41. The weighted average Index for the larger set of 118 PODs now known, was 0.43, lending credence to this assumption. Based on this assumption, a weighted average Handy-Whitman Index was computed for the 118 known PODs and applied to the remaining 138 PODs. This weighted Index was the equivalent of an average energization date of 1976. (See Exhibit C)

Replacement of Facilities at End of Life

As previously mentioned, BPA began establishing GTA PODs in the 1940's. BPA transmission lines have a life of roughly 40 years and substations a life of 34 years. Had BPA constructed facilities to serve the PODs energized prior to 1959, those facilities would very likely have been replaced sometime between 1980 and 1999, creating additional BPA construction costs and thus adding to the total benefits provided by GTAs. Determining these additional benefits was deemed to be beyond the scope of this study, and therefore they are not reflected in the results. However, rough calculations indicate that they would have amounted to at least $3 million/yr.

The South Idaho Exchange

The South Idaho Exchange was negotiated by BPA with PacifiCorp in the late 1980's to avoid the increasing costs of the Idaho Power GTA. Under this agreement PacifiCorp delivers power for BPA at Goshen substation to serve the requirements of BPA Preference Customers in Southeast Idaho and Wyoming in exchange for BPA delivering that exact same amount of power to PODs on PacifiCorp's main system. Because the South Idaho Exchange was in lieu of higher GTA costs it is regarded as "GTA like" in function and its benefits are included in the GTA benefits.

The BPA Annual GTA Budget

BPA's annual GTA budget for 2002 was $38,200,264 and the South Idaho Exchange Budget was computed to be $6,375,000, for an annual total of $44,575,264.

Acknowledgements

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Thanks also to the following individuals and organizations for their peer review of this work and their helpful insights, suggestions and questions: Nancy Baker and Margot Lutzenhiser at the Public Power Council, Aleka Scott at Pacific NW Generating Cooperative, Lon Peters at NW Economic Research and John Saven and Geoff Carr at NW Requirements Utilities.

Special thanks to the members of the Public Power Council who scoured their files to find the energization dates of so many GTA PODs.

Exhibits

Some exhibits have been referred to in the body of this preliminary report, while others have no such specific mention. A comprehensive list of the attached exhibits is:

Exhibit A Cost-Benefit Analysis Spreadsheet
Exhibit B BPA Construction Cost Estimates
Exhibit C Discounting for Age of Facilities
Exhibit D BPA Annual Cost Ratios
Exhibit E South Idaho Study

EXHIBIT A

COST –BENEFIT ANALYSIS
SPREADSHEET

BPA GTA Cost/Benefit Analysis Spreadsheet

Customer	Point of Delivery	Transferor	Deliv. Voltage	Line Miles	Trans. Line Constr. Cost	Substation Constr. Cost	POD Vint.	H W Index	Line A&G/O&M	Line I&A	Substation A&G/O&M	Substation I&A
Benton REA	Horn Rapids	Benton Pud	12.5	6	$1,138,320	$2,241,060	?	0.43	$78,202.58	$19,823.84	$117,655.65	$59,361.20
Benton REA	Plymouth	Benton Pud	115	5.5	$1,043,460	$2,241,060	?	0.43	$71,685.70	$18,171.86	$117,655.65	$59,361.20
Benton REA	Sun Heaven No. 2	Benton Pud	115	11.5	$2,181,780	$2,241,060	?	0.43	$149,888.29	$37,995.70	$117,655.65	$59,361.20
Klickitat PUD	M.A. Collins	Benton Pud	115	13.5	$2,561,220	$2,241,060	?	0.43	$175,955.81	$44,603.65	$117,655.65	$59,361.20
Big Bend	Eltopia	Frank. PUD	115	16	$3,035,520	$2,241,060	83	0.68	$208,540.22	$83,598.22	$117,655.65	$93,873.52
Big Bend	Star School	Frank. PUD	7.2	9	$1,707,480	$2,241,060	?	0.43	$117,303.88	$29,735.76	$117,655.65	$59,361.20
Big Bend	North Pasco	Frank. PUD	12.5	7	$1,328,040	$1,841,640	92	0.84	$91,236.35	$45,179.92	$96,686.10	$95,293.82
Kittitas PUD #1	Jerico	Grant PUD	13.8	9	$1,707,480	$5,525,880	?	0.43	$117,303.88	$29,735.76	$290,108.70	$146,369.51
Kittitas PUD #1	Mattawa	Grant PUD	13.8	9	$1,707,480	$2,241,060	?	0.43	$117,303.88	$29,735.76	$117,655.65	$59,361.20
Big Bend	Schrag	Grant PUD	115	13	$2,466,360	$1,841,640	78	0.48	$169,438.93	$47,946.04	$96,686.10	$54,453.61
Glacier Elec.	Cut Bank	MPC	115	95	$18,023,400	$2,241,060	?	0.43	$1,238,207.58	$313,877.51	$117,655.65	$59,361.20
Missoula Elec.	Bitterroot	MPC	12.5	7	$1,328,040	$2,241,060	?	0.43	$91,236.35	$23,127.82	$117,655.65	$59,361.20
Missoula Elec.	Clinton	MPC	100	7	$1,328,040	$15,297,060	78	0.48	$91,236.35	$25,817.10	$803,095.65	$452,303.47
Missoula Elec.	Frenchtown	MPC	100	25	$4,743,000	$1,841,640	63	0.16	$325,844.10	$30,734.64	$96,686.10	$18,151.20
Missoula Elec.	Huson	MPC	100	16	$3,035,520	$1,841,640	75	0.39	$208,540.22	$47,946.04	$96,686.10	$44,243.56
Missoula Elec.	Lolo	MPC	12.5	10	$1,897,200	$1,841,640	82	0.66	$130,337.64	$50,712.16	$96,686.10	$74,873.72
Missoula Elec.	Miller Creek	MPC	12.5	15	$2,845,800	$1,841,640	?	0.43	$195,506.46	$49,559.61	$96,686.10	$48,781.36
Missoula Elec.	Miltown (Bonner)	MPC	12.5	6	$1,138,320	$1,841,640	81	0.63	$78,202.58	$29,044.23	$96,686.10	$71,470.37
Missoula Elec.	Ovando	MPC	230	24	$4,553,280	$1,841,640	81	0.63	$312,810.34	$116,176.94	$96,686.10	$71,470.37
Missoula Elec.	Tarkio	MPC	100	18	$3,414,960	$1,841,640	90	0.83	$234,607.75	$114,793.88	$96,686.10	$94,159.37
Missoula Elec.	Petty Creek	MPC		12	$2,276,640	$2,241,060	?	0.43	$156,405.17	$39,647.69	$117,655.65	$59,361.20
Northern Lights	Thompson Falls	MPC	12.5	1	$189,720	$1,841,640	?	0.43	$13,033.76	$3,303.97	$96,686.10	$48,781.36
Northern Lights	Cherry Creek	MPC		2	$379,440	$4,241,380	?	0.43	$26,067.53	$6,607.95	$222,672.45	$112,345.67
Ravalli	Corvallis	MPC	69	6	$1,138,320	$1,841,640	79	0.51	$78,202.58	$23,512.00	$96,686.10	$57,856.96
Ravalli	Darby	MPC	12.5	17	$3,225,240	$1,841,640	50	0.11	$221,573.99	$14,368.44	$96,686.10	$12,478.95
Ravalli	Grantsdale	MPC	69	16	$3,035,520	$1,841,640	75	0.39	$208,540.22	$47,946.04	$96,686.10	$44,243.56
Ravalli	Stevensville	MPC	69.5	38	$7,209,360	$1,841,640	63	0.16	$495,283.03	$46,716.65	$96,686.10	$18,151.20
Ravalli	Victor	MPC	69	6	$1,138,320	$1,841,640	74	0.33	$78,202.58	$15,213.65	$96,686.10	$37,436.86
Vigilante	Bannock	MPC	69	16	$3,035,520	$1,841,640	?	0.43	$208,540.22	$52,863.58	$96,686.10	$48,781.36
Vigilante	Dell	MPC	161	85	$16,126,200	$1,841,640	67	0.19	$1,107,869.94	$124,091.11	$96,686.10	$21,554.55
Vigilante	Dillon	MPC		45	$8,537,400	$1,841,640	?	0.43	$586,519.38	$148,678.82	$96,686.10	$48,781.36
Vigilante	Dillon-Salmon	MPC	69	8	$1,517,760	$1,841,640	75	0.39	$104,270.11	$23,973.02	$96,686.10	$44,243.56
Vigilante	East Bench	MPC	12.5	12	$2,276,640	$1,841,640	70	0.22	$156,405.17	$20,284.86	$96,686.10	$24,957.91
Vigilante	Gates of the Mtn.	MPC	12.5	72	$13,659,840	$1,841,640	79	0.51	$938,431.01	$282,144.00	$96,686.10	$57,856.96
Vigilante	Lump Gulch	MPC	12.5	17	$3,225,240	$1,841,640	79	0.51	$221,573.99	$66,617.33	$96,686.10	$57,856.96
Vigilante	Point of Rocks	MPC	69	12	$2,276,640	$1,841,640	67	0.19	$156,405.17	$17,518.74	$96,686.10	$21,554.55
Vigilante	Silver Star	MPC	50	18	$3,414,960	$1,094,970	67	0.19	$234,607.75	$26,278.12	$57,485.93	$12,815.53
Vigilante	Toston	MPC	12.5	6	$1,138,320	$1,841,640	67	0.19	$78,202.58	$8,759.37	$96,686.10	$21,554.55
Vigilante	Townsend	MPC	12.5	24	$4,553,280	$1,841,640	67	0.19	$312,810.34	$35,037.49	$96,686.10	$21,554.55
Vigilante	Whitehall	MPC	50	42	$7,968,240	$1,841,640	67	0.19	$547,418.09	$61,315.61	$96,686.10	$21,554.55
Okanogan Coop	Winthrop	Okanogan P.	13.2	12	$2,276,640	$1,057,040	74	0.33	$156,405.17	$30,427.29	$55,494.60	$21,487.51
Okanogan Coop	Twisp	Okanogan P.	13.2	31	$5,881,320	$1,841,640	?	0.43	$404,046.68	$102,423.19	$96,686.10	$48,781.36
Nespelem	Okanogan	Okanogan P.	13.8	1	$189,720	$4,468,840	70	0.22	$13,033.76	$1,690.41	$234,614.10	$60,561.72

			Deliv.	Line	Trans. Line	Substation	POD	H W	Line	Line	Substation	Substation
Customer	**Point of Delivery**	**Transferor**	**Voltage**	**Miles**	**Constr. Cost**	**Constr. Cost**	**Vint.**	**Index**	**A&G/O&M**	**I&A**	**A&G/O&M**	**I&A**
Big Bend Elec.	Delight SU	WWP	115	37	$7,019,640	$1,841,640	69	0.21	$482,249.27	$59,702.04	$96,686.10	$23,823.46
Big Bend Elec.	Marengo	WWP	24.9	6	$1,138,320	$1,841,640	51	0.12	$78,202.58	$5,532.24	$96,686.10	$13,613.40
Big Bend Elec.	Othello	WWP	13.2	38	$7,209,360	$2,241,060	73	0.27	$495,283.03	$78,834.35	$117,655.65	$37,273.31
Big Bend Elec.	Ralston	WWP	115	21	$3,984,120	$1,841,640	81	0.63	$273,709.04	$101,654.82	$96,686.10	$71,470.37
Big Bend Elec.	Ritzville	WWP	115	14	$2,656,080	$1,841,640	63	0.16	$182,472.70	$17,211.40	$96,686.10	$18,151.20
Big Bend Elec.	Roxboro	WWP	24.9	7	$1,328,040	$2,289,360	77	0.46	$91,236.35	$24,741.39	$120,191.40	$64,871.30
Cheney	Four Lakes/Inld	WWP	115	7	$1,328,040	$1,841,640	54	0.14	$91,236.35	$7,529.99	$96,686.10	$15,882.30
Cheney	Cheney	WWP	115	4	$758,880	$1,841,640	61	0.16	$52,135.06	$4,917.54	$96,686.10	$18,151.20
Chewelah	Chewelah	WWP	13.8	7	$1,328,040	$5,525,880	?	0.43	$91,236.35	$23,127.82	$290,108.70	$146,369.51
Clearwater	Brickens Corner	WWP	115	5.8	$1,100,376	$1,057,040	81	0.63	$75,595.83	$28,076.09	$55,494.60	$41,021.61
Clearwater	Craigmont	WWP	13.2	21	$3,984,120	$1,841,640	87	0.7	$273,709.04	$112,949.80	$96,686.10	$79,411.52
Clearwater	Julietta	WWP	13.8	21.8	$4,135,896	$2,241,060	78	0.48	$284,136.06	$80,401.82	$117,655.65	$66,263.66
Clearwater	Moscow	WWP	24.9	21	$3,984,120	$1,841,640	70	0.22	$273,709.04	$35,498.51	$96,686.10	$24,957.91
Clearwater	Orofino	WWP	24.9	8	$1,517,760	$15,297,060	56	0.15	$104,270.11	$9,220.39	$803,095.65	$141,344.83
Clearwater	Potlatch	WWP	24.9	27.5	$5,217,300	$1,841,640	50	0.11	$358,428.51	$23,243.07	$96,686.10	$12,478.95
Clearwater	Sweetwater	WWP	24.9	25	$4,743,000	$1,841,640	56	0.15	$325,844.10	$28,813.73	$96,686.10	$17,016.75
Clearwater	Weippe	WWP	13.2	25	$4,743,000	$1,841,640	58	0.16	$325,844.10	$30,734.64	$96,686.10	$18,151.20
Fairchild AF Base	Fairchild North AFB	WWP	115	2	$379,440	$1,841,640	?	0.43	$26,067.53	$6,607.95	$96,686.10	$48,781.36
Fairchild AF Base	Fairchild South AFB	WWP	115	1	$189,720	$1,841,640	?	0.43	$13,033.76	$3,303.97	$96,686.10	$48,781.36
Idaho Co. L&P	Cottonwood Joint Use	WWP	24	19.8	$3,756,456	$1,841,640	50	0.11	$258,068.53	$16,735.01	$96,686.10	$12,478.95
Idaho Co. L&P	East Grangeville	WWP	115	24	$4,553,280	$1,841,640	85	0.69	$312,810.34	$127,241.41	$96,686.10	$78,277.07
Idaho Co. L&P	Kamiah Joint Use	WWP	13	18	$3,414,960	$1,841,640	48	0.1	$234,607.75	$13,830.59	$96,686.10	$11,344.50
Idaho Co. L&P	Kooskia Joint Use	WWP	34.5	8	$1,517,760	$1,841,640	56	0.15	$104,270.11	$9,220.39	$96,686.10	$17,016.75
Inland P&L	Airway Heights	WWP	13.8	4	$758,880	$1,841,640	?	0.43	$52,135.06	$13,215.90	$96,686.10	$48,781.36
Inland P&L	Armstrong	WWP	115	16	$3,035,520	$2,241,060	?	0.43	$208,540.22	$52,863.58	$117,655.65	$59,361.20
Inland P&L	Chambers	WWP	115	5	$948,600	$1,841,640	67	0.19	$65,168.82	$7,299.48	$96,686.10	$21,554.55
Inland P&L	Cheney	WWP	115	4	$758,880	$1,841,640	69	0.21	$52,135.06	$6,454.27	$96,686.10	$23,823.46
Inland P&L	Four Lakes	WWP		4	$758,880	$1,841,640	52	0.12	$52,135.06	$3,688.16	$96,686.10	$13,613.40
Inland P&L	East Colfax	WWP	13	28	$5,312,160	$1,841,640	?	0.43	$364,945.39	$92,511.27	$96,686.10	$48,781.36
Inland P&L	Ewan	WWP	13	31	$5,881,320	$1,841,640	?	0.43	$404,046.68	$102,423.19	$96,686.10	$48,781.36
Inland P&L	Hangman	WWP	115	8	$1,517,760	$1,841,640	78	0.48	$104,270.11	$29,505.25	$96,686.10	$54,453.61
Inland P&L	Hayford	WWP	115	8	$1,517,760	$1,841,640	73	0.27	$104,270.11	$16,596.71	$96,686.10	$30,630.16
Inland P&L	Hoodoo	WWP	115	9	$1,707,480	$1,841,640	?	0.43	$117,303.88	$29,735.76	$96,686.10	$48,781.36
Inland P&L	Hopkins EU	WWP	115	7	$1,328,040	$1,841,640	?	0.43	$91,236.35	$23,127.82	$96,686.10	$48,781.36
Inland P&L	Mica	WWP	115	6	$1,138,320	$1,841,640	73	0.27	$78,202.58	$12,447.53	$96,686.10	$30,630.16
Inland P&L	Milan	WWP	13.8	9	$1,707,480	$1,841,640	?	0.43	$117,303.88	$29,735.76	$96,686.10	$48,781.36
Inland P&L	Moab	WWP	115	4	$758,880	$1,841,640	?	0.43	$52,135.06	$13,215.90	$96,686.10	$48,781.36
Inland P&L	Rosalia	WWP	13	9	$1,707,480	$1,841,640	?	0.43	$117,303.88	$29,735.76	$96,686.10	$48,781.36
Inland P&L	Spangle	WWP	13.2	18	$3,414,960	$1,841,640	?	0.43	$234,607.75	$59,471.53	$96,686.10	$48,781.36
Inland P&L	Gaffney	WWP	115	22	$4,173,840	$1,057,040	77	0.46	$286,742.81	$77,758.64	$55,494.60	$29,952.29
Inland P&L	Irby	WWP	115	21	$3,984,120	$1,841,640	?	0.43	$273,709.04	$69,383.45	$96,686.10	$48,781.36
Inland P&L	Odessa	WWP	115	11	$2,086,920	$1,841,640	61	0.16	$143,371.40	$13,523.24	$96,686.10	$18,151.20
Inland P&L	Wagner Lake	WWP	115	23	$4,363,560	$1,057,040	74	0.33	$299,776.57	$58,318.98	$55,494.60	$21,487.51
Kootenai Elec.	Appleway	WWP	13.8	2	$379,440	$1,841,640	77	0.46	$26,067.53	$7,068.97	$96,686.10	$52,184.71
Kootenai Elec.	Athol	WWP		11	$2,086,920	$1,841,640	50	0.11	$143,371.40	$9,297.23	$96,686.10	$12,478.95

Customer	Point of Delivery	Transferor	Deliv. Voltage	Line Miles	Trans. Line Constr. Cost	Substation Constr. Cost	POD Vint.	H W Index	Line A&G/O&M	Line I&A	Substation A&G/O&M	Substation I&A
Kootenai Elec.	Dower EU	WWP		3.5	$664,020	$1,841,640	93	0.87	$45,618.17	$23,396.74	$96,686.10	$98,697.17
Kootenai Elec.	O'Gara	WWP	13	9	$1,707,480	$1,841,640	38	0.06	$117,303.88	$4,149.18	$96,686.10	$6,806.70
Kootenai Elec.	Plummer Jnt Sub	WWP	13	25	$4,743,000	$1,841,640	?	0.43	$325,844.10	$82,599.35	$96,686.10	$48,781.36
Kootenai Elec.	Plesant View	WWP	13	3	$569,160	$1,841,640	92	0.84	$39,101.29	$19,362.82	$96,686.10	$95,293.82
Kootenai Elec.	Prairie	WWP	115	8	$1,517,760	$1,841,640	63	0.16	$104,270.11	$9,835.08	$96,686.10	$18,151.20
Kootenai Elec.	Rathdrum	WWP	13.8	2	$379,440	$1,841,640	79	0.51	$26,067.53	$7,837.33	$96,686.10	$57,856.96
Kootenai Elec.	Rockford	WWP	24.9	6	$1,138,320	$1,841,640	68	0.2	$78,202.58	$9,220.39	$96,686.10	$22,689.00
Kootenai Elec.	Scarcello	WWP	115	6	$1,138,320	$1,841,640	84	0.68	$78,202.58	$31,349.33	$96,686.10	$77,142.62
Kootenai Elec.	15th Street	WWP	13.8	4	$758,880	$1,841,640	81	0.63	$52,135.06	$19,362.82	$96,686.10	$71,470.37
Modern Elec.	4th & Harold	WWP		2.5	$474,300	$1,841,640	?	0.43	$32,584.41	$8,259.93	$96,686.10	$48,781.36
Modern Elec.	Locust & Millwood	WWP	12.5	3	$569,160	$1,841,640	?	0.43	$39,101.29	$9,911.92	$96,686.10	$48,781.36
Modern Elec.	Opportunity	WWP	13.2	2.5	$474,300	$1,841,640	?	0.43	$32,584.41	$8,259.93	$96,686.10	$48,781.36
Northern Lights	Cabinet Gorge	WWP	13.8	7	$1,328,040	$5,525,880	?	0.43	$91,236.35	$23,127.82	$290,108.70	$146,369.51
Northern Lights	Noxon	WWP	13.8	2	$379,440	$1,841,640	?	0.43	$26,067.53	$6,607.95	$96,686.10	$48,781.36
Northern Lights	Libby	WWP		4	$758,880	$1,841,640	?	0.43	$52,135.06	$13,215.90	$96,686.10	$48,781.36
Northern Lights	Bustie at Noxon	WWP		1	$189,720	$1,841,640	?	0.43	$13,033.76	$3,303.97	$96,686.10	$48,781.36
Plummer	Plummer	WWP		3	$569,160	$1,841,640	70	0.22	$39,101.29	$5,071.22	$96,686.10	$24,957.91
Columbia River	Dike Road	Claskanie P.	12.5				?	0.43	$0.00	$0.00	$0.00	$0.00
Columbia River	Townsend Road	Claskanie P.	12.5	6	$1,138,320	$1,841,640	?	0.43	$78,202.58	$19,823.84	$96,686.10	$48,781.36
Columbia River	Timoney Road	Claskanie P.	12.5	3	$569,160	$1,841,640	?	0.43	$39,101.29	$9,911.92	$96,686.10	$48,781.36
Columbia River	Scapoose	PGE	12.5	1	$189,720	$1,841,640	?	0.43	$13,033.76	$3,303.97	$96,686.10	$48,781.36
Columbia River	Warren-Yankton	PGE	12.5	2	$379,440	$1,841,640	47	0.09	$26,067.53	$1,383.06	$96,686.10	$10,210.05
Columbia River	Armstrong	PGE	12.5				?	0.43	$0.00	$0.00	$0.00	$0.00
Columbia River	St. Helens	PGE	12.5	1	$189,720	$2,241,060	?	0.43	$13,033.76	$3,303.97	$117,655.65	$59,361.20
Columbia River	Scapoose OATT	PGE	12.5	6	$1,138,320	$1,841,640	?	0.43	$78,202.58	$19,823.84	$96,686.10	$48,781.36
Springfield	Thurston	EWEB	12.5	9	$1,707,480	$1,841,640	?	0.43	$117,303.88	$29,735.76	$96,686.10	$48,781.36
Springfield	Hayden Bridge	EWEB	115	12	$2,276,640	$1,841,640	?	0.43	$156,405.17	$39,647.69	$96,686.10	$48,781.36
Wasco Elec.	Endersby	No. Wasco	69	6	$1,138,320	$2,241,080	79	0.51	$78,202.58	$23,512.00	$117,656.70	$70,405.77
Wasco Elec.	Pine Hollow	No. Wasco	69	6	$1,138,320	$1,841,640	67	0.19	$78,202.58	$8,759.37	$96,686.10	$21,554.55
City of Ashland	Ashland	PAC	12.5	8	$1,517,760	$1,841,640	?	0.43	$104,270.11	$26,431.79	$96,686.10	$48,781.36
City of Ashland	Oak Knoll	PAC	12.5	74	$14,039,280	$1,841,640	?	0.43	$964,498.54	$244,494.06	$96,686.10	$48,781.36
City of Ashland	Mountain Ave.	PAC	115	5	$948,600	$1,841,640	94	0.91	$65,168.82	$34,960.65	$96,686.10	$103,234.97
Cowlitz	Ariel	PAC	115	12	$2,276,640	$1,841,640	92	0.84	$156,405.17	$77,451.29	$96,686.10	$95,293.82
Columbia Power	Ukiah	PAC	69	20	$3,794,400	$1,057,040	?	0.43	$260,675.28	$66,079.48	$55,494.60	$27,998.88
Columbia REA	Dayton	PAC	69	13	$2,466,360	$1,841,640	81	0.63	$169,438.93	$62,929.18	$96,686.10	$71,470.37
Umatilla Elec./CB	Pilot Rock	PAC	12.5	10	$1,897,200	$6,310,480	?	0.43	$130,337.64	$33,039.74	$331,300.20	$167,151.99
Umatilla Electric	Pendleton	PAC	69	3	$569,160	$5,025,980	41	0.06	$39,101.29	$1,383.06	$263,863.95	$18,576.02
Umatilla Electric	Hat Rock	PAC	230	12	$7,663,080	$3,822,930	71	0.24	$526,453.60	$74,485.14	$200,703.83	$56,518.20
Douglas Electric	Looking Glass	PAC	69	3	$569,160	$5,025,980	51	0.12	$39,101.29	$2,766.12	$263,863.95	$37,152.04
Klickitat PUD	Bingen	PAC	69	5	$948,600	$1,057,040	48	0.1	$65,168.82	$3,841.83	$55,494.60	$6,511.37
Benton REA	White Swan	PAC	115	21	$3,984,120	$2,241,060	55	0.14	$273,709.04	$22,589.96	$117,655.65	$19,326.90
Central Electric	Pilot Butte	PAC	69	4	$758,880	$5,025,980	?	0.43	$52,135.06	$13,215.90	$263,863.95	$133,128.16
Lane Electric	Dorena	PAC	115	12	$2,276,640	$1,841,640	64	0.17	$156,405.17	$15,674.67	$96,686.10	$19,285.65
Emerald PUD	Creswell	PAC	115	6	$1,138,320	$2,241,060	90	0.83	$78,202.58	$38,264.63	$117,655.65	$114,580.92
Emerald PUD	Powerline	PAC	69	13	$2,466,360	$2,241,060	90	0.83	$169,438.93	$82,906.69	$117,655.65	$114,580.92
OREMET	Oremet	PAC	12.5	2	$379,440	$2,241,060	?	0.43	$26,067.53	$6,607.95	$117,655.65	$59,361.20

			Deliv.	Line	Trans. Line	Substation	POD	H W	Line	Line	Substation	Substation
Customer	**Point of Delivery**	**Transferor**	**Voltage**	**Miles**	**Constr. Cost**	**Constr. Cost**	**Vint.**	**Index**	**A&G/O&M**	**I&A**	**A&G/O&M**	**I&A**
Surprise Valley	Malin	PAC	230	0		$13,455,420	67	0.19	$0.00	$0.00	$706,409.55	$157,482.24
Surprise Valley	Alturas	PAC	12.5	23	$4,363,560	$1,841,640	?	0.43	$299,776.57	$75,991.40	$96,686.10	$48,781.36
Surprise Valley	Austin	PAC	69	15	$2,845,800	$1,841,640	?	0.43	$195,506.46	$49,559.61	$96,686.10	$48,781.36
Surprise Valley	Cederville	PAC	115	18	$3,414,960	$1,841,640	81	0.63	$234,607.75	$87,132.70	$96,686.10	$71,470.37
Surprise Valley	Davis Creek	PAC	115	35	$6,640,200	$1,841,640	81	0.63	$456,181.74	$169,424.70	$96,686.10	$71,470.37
Surprise Valley	Lakeview	PAC	69	65	$12,331,800	$1,841,640	?	0.43	$847,194.66	$214,758.30	$96,686.10	$48,781.36
Tillamook	Mohler	PAC	115	9	$1,707,480	$1,841,640	61	0.16	$117,303.88	$11,064.47	$96,686.10	$18,151.20
Tillamook	Garibaldi	PAC	115	13	$2,466,360	$2,241,060	65	0.17	$169,438.93	$16,980.89	$117,655.65	$23,468.38
Tillamook	Nehalem Tap	PAC	115	3	$569,160	$1,841,060	96	0.97	$39,101.29	$22,359.45	$96,655.65	$110,007.02
Hood River	Woody Guthrie	PAC	69	6	$1,138,320	$2,241,060	68	0.2	$78,202.58	$9,220.39	$117,655.65	$27,609.86
Wasco Electric	Warm Springs	PAC	69	12	$2,276,640	$5,025,980	?	0.43	$156,405.17	$39,647.69	$263,863.95	$133,128.16
Canby Util. Board	Canby	PGE		5	$948,600	$2,241,060	92	0.84	$65,168.82	$32,271.37	$117,655.65	$115,961.41
Canby Util. Board	Twilight	PGE		5	$948,600	$1,841,640	?	0.43	$65,168.82	$16,519.87	$96,686.10	$48,781.36
West Oregon	Patton Valley	PGE	12.5				?	0.43	$0.00	$0.00	$0.00	$0.00
West Oregon	Pike	PGE	12.5				?	0.43	$0.00	$0.00	$0.00	$0.00
West Oregon	Pihl Road	PGE	12.5				?	0.43	$0.00	$0.00	$0.00	$0.00
West Oregon	Scoggins Valley	PGE	12.5	4	$758,880	$2,241,060	?	0.43	$52,135.06	$13,215.90	$117,655.65	$59,361.20
West Oregon	Olny	PAC	12.5	15	$2,845,800	$1,841,060	?	0.43	$195,506.46	$49,559.61	$96,655.65	$48,766.00
West Oregon	Necanicum	PAC	115	18	$3,414,960	$1,841,060	83	0.68	$234,607.75	$94,048.00	$96,655.65	$77,118.32
City of McCleary	Elma	Grays Hbr.	69	12	$2,276,640	$2,241,060	84	0.68	$156,405.17	$62,698.67	$117,655.65	$93,873.52
Blaine	Blaine	Puget	12.5	9	$1,707,480	$5,025,980	67	0.19	$117,303.88	$13,139.06	$263,863.95	$58,824.07
Orcus	Fidalgo #2, 3, & 4	Puget	115	35	$6,640,200	$1,841,640	51	0.12	$456,181.74	$32,271.37	$96,686.10	$13,613.40
Georgia Pacific	Georgia Pacific	Puget		24	$4,553,280	$2,241,060	?	0.43	$312,810.34	$79,295.37	$117,655.65	$59,361.20
Kittitas PUD #1	Teanaway	Puget	34.5	25	$4,743,000	$14,550,390	?	0.43	$325,844.10	$82,599.35	$763,895.48	$385,410.73
Sumas	Sumas	Puget	12.5	24	$4,553,280	$1,841,640	?	0.43	$312,810.34	$79,295.37	$96,686.10	$48,781.36
Tanner	Ames Lake	Puget	115	13	$2,466,360	$5,025,980	?	0.43	$169,438.93	$42,951.66	$263,863.95	$133,128.16
Tanner	Luhr Beach	Puget	12.5	12	$2,276,640	$1,841,640	?	0.43	$156,405.17	$39,647.69	$96,686.10	$48,781.36
Tanner	North Bend	Puget	12.5	18	$3,414,960	$1,841,640	?	0.43	$234,607.75	$59,471.53	$96,686.10	$48,781.36
U.S. Navy	East Arlington	Snohomish	115	9	$1,707,480	$5,025,980	?	0.43	$117,303.88	$29,735.76	$263,863.95	$133,128.16
Alder Mutual	Alder	Tacoma	115	5	$948,600	$1,841,640	?	0.43	$65,168.82	$16,519.87	$96,686.10	$48,781.36
Alder Mutual	LaGrande	Tacoma	12.5	12	$2,276,640	$1,841,640	74	0.33	$156,405.17	$30,427.29	$96,686.10	$37,436.86
Eatonville	Lynch Creek	Tacoma	115	8	$1,517,760	$1,841,640	85	0.69	$104,270.11	$42,413.80	$96,686.10	$78,277.07
Elmhurst	Brookdale	Tacoma	115	3	$569,160	$1,841,640	75	0.39	$39,101.29	$8,989.88	$96,686.10	$44,243.56
Elmhurst	Franz Holmes	Tacoma	115	6	$1,138,320	$5,025,980	82	0.66	$78,202.58	$30,427.29	$263,863.95	$204,336.24
Elmhurst	Haakenson	Tacoma	115	3	$569,160	$2,241,060	77	0.46	$39,101.29	$10,603.45	$117,655.65	$63,502.68
Elmhurst	McCullough	Tacoma	115	3	$569,160	$1,841,640	79	0.51	$39,101.29	$11,756.00	$96,686.10	$57,856.96
Lakeview	Lake Grove	Tacoma	115	7	$1,328,040	$2,241,060	87	0.7	$91,236.35	$37,649.93	$117,655.65	$96,634.51
Lakeview	Lakeview 1	Tacoma	115	2	$379,440	$1,841,640	79	0.51	$26,067.53	$7,837.33	$96,686.10	$57,856.96
Lakeview	Tyee	Tacoma	115	2	$379,440	$1,841,640	85	0.69	$26,067.53	$10,603.45	$96,686.10	$78,277.07
Lewis County	Elbe	Tacoma	115	11	$2,086,920	$1,841,640	?	0.43	$143,371.40	$36,343.71	$96,686.10	$48,781.36
Milton	Surprise Lake	Tacoma	115	7	$1,328,040	$2,241,060	80	0.58	$91,236.35	$31,195.66	$117,655.65	$80,068.59
OHOP	Lynch Creek	Tacoma	115	1	$189,720	$1,841,640	85	0.69	$13,033.76	$5,301.73	$96,686.10	$78,277.07
OHOP	Ohop	Tacoma	115	9	$1,707,480	$5,025,980	90	0.83	$117,303.88	$57,396.94	$263,863.95	$256,968.31
Parkland	Brookdale	Tacoma	115	5	$948,600	$1,841,640	75	0.39	$65,168.82	$14,983.14	$96,686.10	$44,243.56
Parkland	John Curtis	Tacoma	115	4	$758,880	$1,841,640	79	0.51	$52,135.06	$15,674.67	$96,686.10	$57,856.96

Customer	Point of Delivery	Transferor	Deliv. Voltage	Line Miles	Trans. Line Constr. Cost	Substation Constr. Cost	POD Vint.	H W Index	Line A&G/O&M	Line I&A	Substation A&G/O&M	Substation I&A
Penninsula	Artondale 1 & 2	Tacoma	115	4	$758,880	$1,841,640	79	0.51	$52,135.06	$15,674.67	$96,686.10	$57,856.96
Penninsula	Lodholm	Tacoma	115	2	$379,440	$1,841,640	93	0.87	$26,067.53	$13,369.57	$96,686.10	$98,697.17
Penninsula	Narrows	Tacoma	115	13	$2,466,360	$1,841,640	87	0.7	$169,438.93	$69,921.31	$96,686.10	$79,411.52
Penninsula	Purdy	Tacoma	115	6	$1,138,320	$1,841,640	79	0.51	$78,202.58	$23,512.00	$96,686.10	$57,856.96
Penninsula	Minter	Tacoma	115	8	$1,517,760	$1,841,640	2002	1	$104,270.11	$61,469.28	$96,686.10	$113,445.02
Penninsula	Gig Harbor	Tacoma	115	6	$1,138,320	$1,841,640	87	0.7	$78,202.58	$32,271.37	$96,686.10	$79,411.52
Penninsula	Vaughn 1 & 2	Tacoma	115	7	$1,328,040	$1,841,640	78	0.48	$91,236.35	$25,817.10	$96,686.10	$54,453.61
Steilacoom	Lake Bay	Tacoma	115	8	$1,517,760	$1,841,640	?	0.43	$104,270.11	$26,431.79	$96,686.10	$48,781.36
Steilacoom	Steilacoom	Tacoma	115	6	$1,138,320	$1,841,640	81	0.63	$78,202.58	$29,044.23	$96,686.10	$71,470.37
Wells Rural	Carlin	SPPC	230	175	$38,153,500	$5,107,430	75	0.39	$2,621,145.45	$602,634.53	$268,140.08	$122,700.90
Wells Rural	Maggie Ck.	SPPC	230	6	$1,308,120	$4,468,840	85	0.69	$89,867.84	$36,555.41	$234,614.10	$189,943.58
Harney Elec.	Winnemucca	SPPC	230	75	$16,351,500	$1,608,770	80	0.58	$557,586.15	$384,096.74	$84,460.43	$57,478.13
Southern Idaho	See So. Id. Study	IPC/UPL			$ 178,925,000	$ 25,500,000			$ 8,459,595	$ 7,874,518	$ 2,910,326	$ 1,570,800
			TOTAL	**2,648**	**$693,915,828**	**$482,302,870**			**$43,273,703**	**$16,231,743**	**$26,892,477**	**$13,173,322**

ASUMPTIONS

1) ALL NEW TRANSMISIONS LINES WERE 115 KV IBIS ACSR SINGLE POLE WOOD CONSTUCTION
2) SUBSTATION ESTIMATE FOR 12.5 KV WITH 1.5 PCB WAS USED ON SUBS WITH TAPS
3) WHEN A 230/115 KV STATIONS WAS ADDED THE 1.5 PCB ESTIMATED COST WAS USED
4) WHEN MULTIPLE BREAKER POSITIONS WERE ADDED LINE TERMINAL WITH END BAY WAS USED

CALCULATION OF AVOIDED CAPITAL COSTS

Transm. Capital Cost	$693,915,828
Subs. Capital Cost	$482,302,870
Total Capital Cost	$1,176,218,698
Tot. Capital at 30% OH	$ 1,529,084,307
Total Capital at 40% OH	$ 1,646,706,177
Total Capital at 50% OH	$ 1,764,328,047
Total Capital at 30%OH, $ 2004	**$ 1,712,574,424**

Transmission Annual Costs	$59,505,446
Substation Annual Costs	$40,065,798
Total Annual Costs	$99,571,244
Calculated Annual Costs with 30% OH	$129,442,617
CalculatedAnnual Costs with 40% OH	$139,399,741
Calculated Annual Costs with 50% OH	$149,356,866
Ratio of total PODs to located PODs	1.02
Projected Annual Costs with 30% OH	$ 132,021,114
Projected Annual Costs with 40% OH	$ 142,176,584
Projected Annual Costs with 50% OH	$ 152,332,055
2002 GTA Annual Budget	$38,200,264
S. Idaho Exchange Costs	$6,375,000
2002 Total GTA/Exch. Budget	$44,575,264
Projected Benefit with 30% OH	**$87,445,850**
Projected Benefit with 40% OH	**$97,601,320**
Projected Benefit with 50% OH	**$107,756,791**

EXHIBIT B

BPA 1999 COST DATA FOR TRANSMISSION LINE AND OTHER FACILITIES ESTIMATES

Note: As a condition of allowing use of the following tables in the study, BPA asked that the author state that BPA believes it is highly likely that this cost information contained on the following tables are low. Bonneville is in the process of developing new transmission and substation cost estimates, but such estimates were not available at the time of this study.

COST SUMMARY

1999 COST DATA FOR PRELIMINARY TRANSMISSION LINE ESTIMATES

(LAND, ENVIRONMENTAL, & INDIRECT OVERHEADS NOT INCLUDED)

NEW LINE CONSTRUCTION - PER MILE COST

CONDUCTOR		SINGLE CIRCUIT 115 KV			SINGLE CIRCUIT 230 KV			DOUBLE CIRCUIT 230 KV				
		ROLLING TERRAIN			ROLLING TERRAIN		50/50 TERR.	FLAT TERR.	ROLLING TERRAIN			50/50 TERR.
NAME	KCM	SINGLE POLE WOOD	H-FRAME WOOD	DIR. EMBED. STEEL POLE	H-FRAME WOOD	LATT.STEEL TOWER	LATT.STEEL TOWER	LATT.STEEL TOWER	H-FRAME WOOD	DIR. EMBED. STEEL POLE	LATT.STEEL TOWER	LATT.STEEL TOWER
ACSR, IBIS	398	$189,720										
ACSR/TW, PARAKEET	556	$194,570	$200,950									
AAC/TW, BAKER	795	$202,900	$207,490		$218,020							
ACSR/TW, TOUTLE	795			$293,870								
AAC/TW, RAINIER	954		$213,020		$223,290							
ACSR/TW, CLACKAMAS	993					$336,470	$425,440	$372,430			$459,180	$547,730
ACSR/TW, ROGUE	1115					$343,380	$431,480	$384,100		$414,490	$471,330	$559,000
AAC/TW, HELENS	1137	$220,670	$221,180		$232,890							
ACSR/TW, DESCHUTES	1510					$350,360	$441,100	$403,830			$491,760	$579,860
AAC/TW, HOOD	1589	$244,680	$239,670		$253,070				$355,960	$464,060		
ACSR/TW, OWYHEE	1917					$369,620	$457,160	$434,410			$522,930	$610,130
AAC/TW, BACHELOR	1979				$271,590							
AAC/TW, JEFFERSON	2406					$392,420	$479,070	$470,890			$560,070	$648,160

CONDUCTOR		SINGLE CIRCUIT 500 KV				DOUBLE CIRCUIT 500 KV		
		FLAT TERR.	ROLLING TERRAIN		50/50 TERR.	FLAT TERR.	ROLLING	50/50 TERR.
NAME	KCM	LATT.STEEL TOWER	LATT.STEEL TOWER	DIR. EMBED. STEEL POLE	LATT.STEEL TOWER	LATT.STEEL TOWER	LATT.STEEL TOWER	LATT.STEEL TOWER
ACSR, 3-BUNTING	3578	$471,170	$569,210		$660,840			
ACSR, 3-SEAHAWK	5607	$549,490	$663,310	$812,940	$759,280	$1,065,560	$1,239,820	$1,334,950
ACSR/TW,4-DESCHUTES	6039					$1,123,180	$1,294,370	$1,390,790
AAC/TW, 3-JEFFERSON	7218	$592,150	$706,380		$802,800	$1,141,170	$1,316,310	$1,413,590

COST SUMMARY

1999 COST DATA FOR PRELIMINARY ESTIMATES

(LAND, ENVIRONMENTAL, & INDIRECT OVERHEADS NOT INCLUDED)

SUBSTATION TERMINAL ADDITIONS	69 kV	115 kV	230 kV	500 kV
Line Terminal, No Yard Expansion, End Bay	$277,530	$399,420	$638,590	
Line Terminal, No Yard Expansion, Open Bay		$369,280		
Line Terminal, Yard Expansion, End Bay		$502,910	$717,790	
Line Terminal, No Yard Expansion, Ring or 1-1/2 Breaker Arrange. in Exist. Yd			$649,500	
Line Terminal, No Yard Expansion, Completion of Existing Bay				$1,534,990
Bus Tie Terminal, No Yard Expansion, Inside Bay		$339,220	$491,970	
PCB Bay, No Yard Expansion, End Bay				$4,535,740
PCB Bay, Yard Expansion, End Bay				$4,707,510

NEW STATIONS	115 kV	230 kV	500 kV
12.5 kV Station	$1,057,040		
12.5 kV Station - No low side equipment, 1.5 PCB with 1200A Isolating Sw.	$1,841,640		
13.8 kV Station - No low side equipment, 1.5 PCB with 1200A Isolating Sw.		$4,468,840	
25 kV Station	$1,091,100		
34.5 kV Station	$1,094,970		
69 kV Customer Feeder Station		$1,608,770	
1.5 PCB Station		$3,184,340	
230 kV Station			$13,455,420

CUSTOMER FEEDER ADDITIONS	12.5 kV	13.8 kV	25 kV	34.5 kV	69 kV
Customer Feeder Addition	$139,260	$139,260	$171,750	$178,410	$249,310
Customer Feeder Addition, Add a 115 kV/13.8kV, 25 MVA Transformer		$822,290			

COST SUMMARY

1999 COST DATA FOR PRELIMINARY ESTIMATES

(LAND, ENVIRONMENTAL, & INDIRECT OVERHEADS NOT INCLUDED)

PHASE SHIFTER ADDITIONS	230 kV	500 kV
600 MVA, +/- 40 degrees, with yard expansion	$7,576,470	
650 MVA, 0-16 degrees, no yard expansion		$11,908,600
1400 MVA, 16-30 degrees, no yard expansion		$22,296,120

TRANSFORMER ADDITIONS	115 kV - 34.5 kV	230 kV - 115 kV	500 kV - 230 kV
25 MVA, no yard expansion, add new transformer in parallel w/o add'l breaker	$595,670		
200 MVA, with a 115 kV terminal		$3,014,910	
300 MVA, assume 230kV & 115kV terminals exist and no add'l breakers		$2,682,500	
700 MVA, no yard expansion, transformer connected to 500 kV bus			$8,665,680
1300 MVA, no yard expansion, transformer connected to 500 kV bus			$10,381,400
1800 MVA, no yard expansion, transformer connected to 500 kV bus			$11,639,250

TRANSFORMER REPLACEMENTS	115 kV 25/50 KVA PVTs	115 kV 50/100 KVA PVTs	230 kV 25/50 KVA PVTs	230 kV 50/100 KVA PVTs
Replace 13.8 kV substation transformers	$136,190	$148,190	$273,800	$297,950

COST SUMMARY

1999 COST DATA FOR PRELIMINARY ESTIMATES

(LAND, ENVIRONMENTAL, & INDIRECT OVERHEADS NOT INCLUDED)

SHUNT CAPACITOR GROUP ADDITIONS	13.8 kV	115 kV	230 kV	500 kV
10 MVAR, no yard expansion	$270,150			
20 MVAR, no yard expansion, assume adjacent to existing capacitor group		$365,260		
51 MVAR, no yard expansion, assume adjacent to existing capacitor group		$487,860		
60 MVAR, yard expansion		$1,117,550		
102 MVAR, no yard expansion, assume adjacent to existing capacitor group			$864,050	
168 MVAR, no yard expansion, assume adjacent to existing capacitor group			$1,149,900	
168 MVAR, no yard expansion, existing switching will be retained			$904,170	
180 MVAR, no yard expansion				$2,048,660
300 MVAR, no yard expansion				$2,673,410

SHUNT CAPACITOR REPLACEMENTS	13.8 kV - 230 kV
10 MVAR, includes all voltages 230 kV and below	$310,930

POWER CIRCUIT BREAKER ADDITIONS	115 kV	230 kV	500 kV
With disconnect switch	$230,230	$326,280	
Without disconnect switch (assumes isolating switches exist)			$641,180
With motor operated disconnect switch			$688,770
Replace with a 115 kV, 2000A breaker	$142,300		
Replace with a 230 kV, 2000A breaker		$213,560	
Replace with a 500 kV, 3000A breaker			$567,280

COST SUMMARY

1999 COST DATA FOR PRELIMINARY ESTIMATES

(LAND, ENVIRONMENTAL, & INDIRECT OVERHEADS NOT INCLUDED)

POWER CIRCUIT BREAKER REPLACEMENTS	15 kV	23 kV	34.5 kV	69 kV	500 kV
Replace with a 15 kV, 560A recloser	$40,720				
Replace with a 23 kV, 560A recloser		$46,440			
Replace with a 34.5 kV, 1200A breaker			$70,500		
Replace with a 69 kV, 1200A breaker				$79,690	
Replace the 500 kV current transformers on a live tank PCB					$230,010

MISCELLANEOUS CAPACITOR GROUP ESTIMATES	
Cleanup and disposal of 69 kV capacitor groups	$137,690
Remove 230 kV 153 MVAR capacitor group	$216,430
Add a 230 kV, 1600Amp capacitor switcher	$216,410
Add a 230 kV, 2000Amp circuit switcher	$266,780

SERIES CAPACITOR ADDITIONS	500 kV
No land will be purchased	$8,106,610
Yard will be expanded	$4,195,580

SHUNT REACTOR ADDITIONS	500 kV
180 MVAR, no yard expansion	$3,869,440
300 MVAR, no yard expansion	$5,031,610

COST SUMMARY

1999 COST DATA FOR PRELIMINARY ESTIMATES

(LAND, ENVIRONMENTAL, & INDIRECT OVERHEADS NOT INCLUDED)

STATIC VAR COMPENSATORS	230 kV
300 MVAR	$23,912,760

FUSE REPLACEMENT	23 kV	34.5 kV	69 kV	115 kV
Replace H.V. fuses with current limiting reactors and a PCB	$184,680	$199,880	$249,880	
Replace H.V. fuses with a self-contained circuit switcher				$99,630
Replace SS liquid fuses with a MOD and voltage detection scheme	$114,750			
Replace SS liquid fuses with a MOD and voltage detection scheme		$126,450		
Replace SS liquid fuses with a MOD and voltage detection scheme			$202,500	

LINE LOSS LOGIC ADDITION	500 kV	DITTMER CC	MUNRO CC
Includes LLL units, mod aux. 'B' switches, MUX channel, ser & SCADA misc.	$231,680		
Assume breaker and a half. Install 2 LLL units, 2 MWTT units & 2 com chanls	$336,030		
Install LLL at 500 kV station. Include 2 MWTT, 2 MUX channels & add'l labor		$82,960	$82,960

DISCONNECT SWITCHES & SURGE ARRESTERS	
Replace 115 kV disconnect switches	$75,720
Replace 230 kV disconnect switches	$114,360
Add 5 vacuum bottles to 115 kV or 230 kV disconnect switch	$33,090
Replace 500 kV rod gaps with surge arrestors	$79,080
Replace the surge arresters on a 500/230-34.5 kV transformer bank	$72,200

COST SUMMARY

1999 COST DATA FOR PRELIMINARY ESTIMATES

(LAND, ENVIRONMENTAL, & INDIRECT OVERHEADS NOT INCLUDED)

MISCELLANEOUS	
Add station service from a local power utility source	$24,650
Add 115 kV, 20.3 MVAR mobile capacitor bank	$64,930
Add a 15 kV PCB and insulation on the low side incl bypass switch	$119,620
Add insulation on the low volt bus between transformer & low side breaker	$59,090
Add a 13.8 kV voltage regulator	$174,390

To: "'Patrick G McRae'" <fishbums1@juno.com>
Date: Wed, 21 Jan 2004 22:33:02 -0800
Subject: RE: BPA Construction Cost Estimates
Message-ID: <CB9370ACBDEA86429FBFA24755EDA0E9033D5DC2@exrs01.bud.bpa.gov>

Pat

30% for overheads is a good round number.
Environmental costs could be $5M for a big line project Land costs are anybody's guess (federal land is free)

Id be interested to see your findings

Brian

-----Original Message-----
From: Patrick G McRae [mailto:fishbums1@juno.com]
Sent: Wednesday, January 21, 2004 11:54 AM
To: blsilverstein@bpa.gov
Subject: BPA Construction Cost Estimates

Hi Brian.

We're pretty far along on the GTA Cost-Benefit analysis that I'm doing for ICUA, but I have a question regarding the construction cost estimates you provided me. They don't include costs for land, environmental, and indirects, and I don't have any idea what I should use as a proxy for that. Could you provide me with some percentage for that, that BPA would agree is credible? Lower Valley Power and Light's engineer, who is doing most of the work for me on this study said on their last cost sharing project that BPA was using an overhead allocation of between 20% to 35% depending on the specifics. Any suggestions?

Pat Mc.

EXHIBIT C

Discounting for Age of Facilities

Exhibit C

Discounting for Age of Facilities

The energization dates are known for only the 56 of the 256 GTA PODs. Those 56 PODs include a BPA substation or other facilities, thus making that information readily available. The remaining 200 PODs have customer owned substations or facilities, and their energization dates are not readily available. The study will utilize readily available information and make "reasonable assumptions" for information that is not readily available.

It is reasonable to assume that the distribution of energization dates for the 200 PODs with unknown energization dates would roughly follow the distribution of energization dates for the known 56 PODs.

Decade	**No. of PODs**	**Year**	**Handy Whitman Index**	**Total PODs X Handy-Whitman**
1990's	3	1995	0.96	2.88
1980's	17	1985	0.69	11.73
1970's	13	1975	0.39	5.07
1960's	15	1965	0.17	2.55
1950's	5	1955	0.14	0.7
1940's	3	1945	0.07	0.21
Sum	56			23.14

Weighted Average Handy-Whitman Index = 23.14/56 = 0.41

Applying this weighted average Handy-Whitman Index to all the 200 PODs with unknown energization dates is the same, i.e. yields the same result as if we applied a "decade percentage" to all the unknown PODs to come up with a "decade total" and applied the "decade" Handy-Whitman to each of the "decade totals."

EXHIBIT D

BPA Annual Cost Ratios

Bonneville Power Administration
Fiscal Year 1998/1999 Annual Financial Requirements as a Percentage of Plant Investment
O&M Based Upon Years 1997, 1998, and 1999 Averages

	Direct Operations					Joint Use Facilty 3/			Surplus Facility 4/			New Facility 5/		
	Operation	Maintenance	Total	Administration and General	Total Operation and Maintenance	Interest And Amortization	Total Direct	Total Includes General Plant	Interest And Amortization	Total Direct	Total Includes General Plant	Interest And Amortization	Total Direct	Total Includes General Plant
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
SUBSTATION TYPE			(1)+(2)		(3)+(4)		(5)+(6)			(5)+(9)			(5)+(12)	
R7 CELILO	0.17%	0.30%	0.47%	0.49%	0.96%	7.46%	8.42%	9.24%	7.63%	8.59%	9.42%	7.88%	8.84%	9.69%
FO	2.39%	4.07%	6.46%	6.57%	13.03%	7.65%	20.68%	21.50%	7.82%	20.85%	21.68%	8.07%	21.10%	21.95%
H5	0.69%	1.17%	1.86%	1.89%	3.75%	7.62%	11.37%	12.19%	7.79%	11.54%	12.37%	8.04%	11.79%	12.64%
U	0.96%	1.64%	2.60%	2.65%	5.25%	7.65%	12.90%	13.72%	7.82%	13.07%	13.90%	8.07%	13.32%	14.17%
SA	0.17%	0.28%	0.45%	0.46%	0.91%	7.50%	8.41%	9.23%	7.67%	8.58%	9.41%	7.92%	8.83%	9.68%
SH	0.56%	0.96%	1.52%	1.55%	3.07%	7.49%	10.56%	11.38%	7.66%	10.73%	11.56%	7.92%	10.99%	11.84%
METERING STATIONS	3.21%	5.47%	8.68%	8.82%	17.50%	7.66%	25.16%	25.98%	7.83%	25.33%	26.16%	8.07%	25.57%	26.42%
COMPOSITE SUB STATIONS	0.70%	1.18%	1.88%	1.91%	3.79%	7.60%	11.39%	12.21%	7.77%	11.56%	12.39%	8.02%	11.81%	12.66%
LINES														
1000 KV DC	0.27%	2.10%	2.37%	2.41%	4.78%	6.89%	11.67%	12.49%	7.01%	11.79%	12.62%	7.29%	12.07%	12.92%
500 KV	0.08%	0.58%	0.66%	0.67%	1.33%	6.88%	8.21%	9.03%	7.00%	8.33%	9.16%	7.29%	8.62%	9.47%
115-345 KV STEEL	0.33%	2.53%	2.86%	2.91%	5.77%	10.35%	16.12%	16.94%	10.64%	16.41%	17.24%	11.08%	16.85%	17.70%
115-230 KV WOOD	0.40%	3.01%	3.41%	3.46%	6.87%	2.16%	9.03%	9.85%	2.17%	9.04%	9.87%	2.26%	9.13%	9.98%
LOW VOLTAGE	0.17%	1.25%	1.42%	1.44%	2.86%	6.84%	9.70%	10.52%	7.03%	9.89%	10.72%	7.31%	10.17%	11.02%
SUBMARINE CABLES	0.68%	5.06%	5.74%	4.51%	10.25%	7.82%	18.07%	18.89%	7.98%	18.23%	19.06%	8.22%	18.47%	19.32%
COMPOSITE LINES	0.18%	1.36%	1.54%	1.56%	3.10%	6.86%	9.96%	10.78%	7.01%	10.11%	10.94%	7.29%	10.39%	11.24%
COMPOSITE TRANSMISSION PLANT	0.44%	1.27%	1.71%	1.73%	3.44%	7.23%	10.67%	11.49%	7.38%	10.82%	11.65%	7.65%	11.09%	11.94%
GENERAL PLANT														
LAND & BUILDING	3.07%	5.19%	8.26%	8.39%	16.65%	6.75%	23.40%		6.95%	23.60%		7.24%	23.89%	
COMMUNICATION EQUIP	0.10%	0.17%	0.27%	0.27%	0.54%	10.77%	11.31%		10.91%	11.45%		11.12%	11.66%	
OTHER 1/	0.06%	0.10%	0.16%	0.17%	0.33%	9.56%	9.89%		9.72%	10.05%		9.97%	10.30%	
COMPOSITE PLANT	0.09%	0.16%	0.25%	0.25%	0.50%	9.93%	10.43%		10.09%	10.59%		10.32%	10.82%	
COMPOSITE - SYSTEM 2/	0.36%	1.03%	1.39%	1.41%	2.80%	7.81%	10.61%		7.97%	10.77%		8.23%	11.03%	

1/ Includes all portable property substation, emergency spare transformers, dataprocessing equipment, lab equipment, aircraft equipment, etc.
2/ Based on Average Service Life from 8 to 100 years overall composite life equals approximately 40 years.
3/ Based upon BPA's composite interest rate of 6.7% for unamortized investment and borrowing through FY 1999.
4/ Based on BPA's opportunity cost of money, 6.9% (the weighted average of outstanding bonds).
5/ Based on BPA's projected long-term borrowing rate of 7.2%.

Bonneville Power Administration
Fiscal Year 1998/1999 Annual Financial Requirements as a Percentage of Plant Investment
O&M Based Upon Years 1997, 1998, and 1999 Averages

	Number Of Units		Maintenance Direct	Maintenance Indirect	Station General	Operations Direct	Operations Indirect	Total O&M	Administrative & General	Total Expense	Average Service Life
Main Grid Substation Components											
500 KV PCB Terminal - Gas	298		$10,346	$2,130	$1,496	$6,400	$561	$20,933	$4,733	$25,666	34
230 KV PCB Terminal - Gas	324		$2,671	$550	$386	$1,650	$145	$5,402	$1,222	$6,624	34
230 KV PCB Terminal - Oil	272		$3,078	$634	$444	$1,902	$166	$6,224	$1,409	$7,633	34
500/230 KV Transformer Banks	40		$34,913	$7,181	$5,053	$21,603	$1,892	$70,642	$15,995	$86,637	34
230/115 KV Transfomer Banks	145		$13,541	$2,785	$1,960	$8,378	$734	$27,398	$6,203	$33,601	34
Under 115 KV	297		$5,401	$1,113	$782	$3,342	$292	$10,930	$2,474	$13,404	34
500 KV Shunt Reactor	5,816,000	kvar	$0.037300	$0.005800	$0.016600	$0.017600	$0.004100	$0.081400	$0.030500	$0.111900	34
230 Shunt Reactor	1,225,000	kvar	$0.021300	$0.002100	$0.005400	$0.062900	$0.055200	$0.146900	$0.025900	$0.172800	34
Series Capacitors	5,431,100	kvar	$0.012164	$0.002501	$0.001760	$0.007527	$0.000659	$0.024611	$0.005570	$0.030181	34
Shunt Capacitors	13,775,360	kvar	$0.052956	$0.010890	$0.007664	$0.032767	$0.002868	$0.107145	$0.024257	$0.131402	34
Transmission LInes	Circuit Miles					Cost Per Circuit Mile					
1000 KV Direct Current Steel	266.8		$1,285			$182		$1,467	$1,245	$2,712	65
500 KV Steel	4,520.9		$1,237			$176		$1,413	$1,197	$2,610	65
115/345 KV Steel	5,888.0		$820			$116		$936	$819	$1,755	65
115/230 KV Wood	4,097.0		$1,055			$149		$1,204	$1,021	$2,225	50
Low Voltage	271.0		$862			$122		$984	$835	$1,819	55
	15,043.7										

Substation Type Definitions

Type R7 - Rotating shifts, full coverage, 24 hours a day, seven days a week.

Type FO - Owned by a foreign company. Operated by BPA.

Type H5 - Standard schedule, five days a week. (not required for reliability criteria)

Type SA - On duty four hours per day, on call 20 hours per day.

Type U - Unattended

Type SH - Shared Facility. Owned by BPA and another utility.

BONNEVILLE POWER ADMINISTRATION
ANNUAL FINANCIAL REQUIREMENTS AS A PERCENTAGE OF PLANT INVESTMENT
BASED ON
AVERAGE PLANT INVESTMENT AND AVERAGE O&M FOR FY 1972 AND 1973

	Direct Operation & Maintenance			Admin. &	Total	3 1/8% Interest			5 5/8% Interest			5 7/8% Interest			6 1/8% Inter	
	Operation	Maint.	Total	General	O&M	Interest & Amort.	Total Direct	Total, Incld. General Plant	Interest & Amort.	Total Direct	Total, Incld. General Plant	Interest & Amort.	Total Direct	Total, Incld. General Plant	Interest & Amort.	Total Direct
Column No.	(1)	(2)	(3)	(4)	(5)	(6)	(7) Col. (5)+(6)	(8)	(9)	(10) Col. (5)+(9)	(11)	(12)	(13) Col. (5)+(12)	(14)	(15)	(16) Col. (5)+(15)
TRANSMISSION PLANT																
Substations																
Operational Coverage																
Type R	2.44	1.58	4.02	1.22	5.24	4.69	9.93	10.74	6.57	11.81	12.74	6.77	12.01	12.96	6.97	12.21
Type R Celilo Terminal	0.63	0.55	1.18	0.36	1.54	4.62	6.16	6.97	6.51	8.05	8.98	6.72	8.26	9.21	6.92	8.46
Type R - D5/C7	1.32	1.35	2.67	0.81	3.48	4.71	8.19	9.00	6.59	10.07	11.00	6.79	10.27	11.22	6.99	10.47
Type F	0.07	0.83	0.90	0.29	1.19	4.73	5.92	6.73	6.59	7.78	8.71	6.80	7.99	8.94	7.00	8.19
Type C7	1.79	1.54	3.33	1.00	4.33	4.69	9.02	9.83	6.57	10.90	11.83	6.77	11.10	12.05	6.98	11.31
Type SC7	1.03	1.80	2.83	0.85	3.68	4.74	8.42	9.23	6.62	10.30	11.23	6.82	10.50	11.45	7.02	10.70
Type C5	1.28	1.83	3.11	0.94	4.05	4.60	8.65	9.46	6.51	10.56	11.49	6.71	10.76	11.71	6.92	10.97
Type S5	1.42	1.51	2.93	0.88	3.81	4.70	8.51	9.32	6.58	10.39	11.32	6.78	10.59	11.54	6.99	10.80
Type S7	2.53	1.99	4.52	1.40	5.92	4.78	10.70	11.51	6.64	12.56	13.49	6.84	12.76	13.71	7.04	12.96
Type U	1.37	1.84	3.21	0.95	4.16	4.67	8.83	9.64	6.55	10.71	11.64	6.75	10.91	11.86	6.95	11.11
Metering Stations	14.75	15.78	30.53	9.14	39.67	4.73	44.40	45.21	6.60	46.27	47.20	6.80	46.47	47.42	7.00	46.67
Composite of Substations	1.68	1.54	3.22	0.97	4.19	4.68	8.87	9.68	6.56	10.75	11.68	6.77	10.96	11.91	6.97	11.16
Lines																
800 kV Direct Current-Steel & Al.	0.12	0.26	0.38	0.11	0.49	3.94	4.43	5.24	6.21	6.70	7.63	6.21	6.70	7.65	6.43	6.92
500 kV Steel	0.12	0.31	0.43	0.13	0.56	3.91	4.47	5.28	6.20	6.76	7.69	6.20	6.76	7.71	6.42	6.98
115-345 kV-Steel	0.12	0.62	0.74	0.22	0.96	3.91	4.87	5.68	6.20	7.16	8.09	6.20	7.16	8.11	6.42	7.38
115-230 kV-Wood	0.12	2.27	2.39	0.71	3.10	4.11	7.21	8.02	6.36	9.46	10.39	6.36	9.46	10.41	6.58	9.68
Low Voltage	0.12	4.64	4.76	1.44	6.20	4.16	10.36	11.17	6.38	12.58	13.51	6.38	12.58	13.53	6.58	12.78
Submarine Cable	0.12	1.45	1.57	0.44	2.01	5.81	7.82	8.63	7.71	9.72	10.65	7.71	9.72	10.67	7.90	9.91
Composite Lines	0.12	0.76	0.88	0.26	1.14	3.95	5.09	5.90	6.23	7.37	8.30	6.23	7.37	8.32	6.45	7.59
Composite Transmission Plant	0.76	1.08	1.84	0.55	2.39	4.24	6.63	7.44	6.23	8.62	9.55	6.45	8.84	9.79	6.66	9.05
GENERAL PLANT																
Land and Buildings	0.05	1.91	1.96	0.58	2.54	4.39	6.93		6.32	8.86		6.53	9.07		6.74	9.28
Microwave		5.34	5.34	1.60	6.94	6.32	13.26		8.01	14.95		8.19	15.13		8.37	15.31
Radio		9.57	9.57	2.88	12.45	6.31	18.76		8.00	20.45		8.18	20.63		8.36	20.81
Other 3/	0.60	2.72	3.32	1.00	4.32	7.90	12.22		9.58	13.90		9.76	14.08		9.94	14.26
Composite General Plant	0.29	3.64	3.93	1.18	5.11	6.59	11.70		8.33	13.44		8.51	13.62		8.70	13.81
Composite Over-all System	0.73	1.24	1.97	0.59	2.56	4.39	6.95		6.36	8.92		6.58	9.14		6.79	9.35
				1/		2/			2/			2/			2/	

1/ 30.16% of direct O&M. Column 4 includes, in addition to cash appropriations, imputed costs for GSA rents, legal services and GAO audits.
2/ Based on age life groups ranging from 8 to 100 years. Over-all composite life equals approximately 41 years.
3/ Includes all portable property plus portable substations, emergency spare transformers and dispatching equipment at the Portland Control Center.

BPA ANNUAL COST RATIOS -- DISCUSSION

Note: BPA and the author agreed that the Interest and Amortization factor of 2.16% for 115-230 KV wood pole lines in the 1997, 1998, 1999 table was in error since it would have to be based on an interest rate of less that ¼% over a 40 year life to yield such a Capital Recover Factor. This was replaced with a Capital Recover Factor based on 2½% over 40 years, which is 3.98%.

This change results in an Annual Cost Ratio of 11.69% for 115-230 KV wood pole lines.

The average of the 1972 and the 1997, 1998, 1999 Annual Cost Ratios for 115-230 KV wood pole lines is: 11.69% + 8.02% = 19.71%/2 = **9.86%**

The average of the 1972 and the 1997, 1998, 1999 Annual Cost Ratios for Type U substations is: 13.72% + 9.64% = 23.26&/2 = **11.68%**

EXHIBIT E

SOUTH IDAHO EXCHANGE
COST –BENEFIT ANALYSIS

Exhibit E

SOUTH IDAHO GTA COST-BENEFIT ANALYSIS

The purpose of this analysis is to compare the annual costs that BPA currently experiences for serving its Southern Idaho loads (via the South Idaho Exchange and GTAs with Idaho Power and Utah Power) with the estimated annual costs that BPA would be experiencing had it constructed the high voltage facilities into Southern Idaho that it proposed in 1963 (hereinafter referred to as "Ghost Facilities"). The GTAs and the Exchange would be considered a "benefit" to BPA if their annual costs are determined to be less than the estimated annual costs of the Ghost Facilities.

The Ghost Facilities
BPA's 1963 High Voltage Transmission Plans For Southern Idaho

In 1963 BPA published a 144 page "Report on Feasibility of Extending Marketing Area of Bonneville Power Administration to Southern Idaho," at the request of then Assistant Secretary of the Interior, Kenneth Holum. That report detailed two BPA alternatives; an AC and a DC alternative for extending a 470 mile high voltage transmission line from Lewiston, Idaho to Soda Springs, Idaho. In addition to the high voltage transmission alternatives, they also provided information on their plans to extend 230 kV or 138 kV facilities to Industrial Loads, and for service to Preference Customers. Lewiston was the starting point for the line because it was expected (or perhaps mostly already a reality) that 500 kV transmission would be extended from Wanapum to Lewiston via the Lower Snake Plants to integrate that generation.

For purposes of this analysis we have examined only the AC alternative as it seemed the most likely to be constructed and the costs for both alternatives were roughly similar. The elements of the plan are described below.

1. <u>High Voltage Transmission to Southern Idaho</u>

BPA planned to construct 470 miles of 500 kV AC line from Lewiston to Soda Springs, and install two 500 kV step down transformers at Soda Springs.

Estimated Cost $149,610,000

<u>2. Service to Industrial Loads</u>

BPA planned to construct 40 miles of 230 kV line from Soda Springs to a 125 MVA substation at Pocatello, and 35 miles of 230 kV line to two 125 MVA customer service substations near Soda Springs, at a total cost of $8,175,000. BPA did not pick up the loads it had expected in Pocatello, so for purposes of the GTA Cost/Benefit Analysis we will assume that only the 35 miles of 230 kV line would have been constructed to serve load that is currently BPA's.

Applicable Estimated Cost = 35/75($8,175,000) = $3,815,000.

3. Secondary Transmission and Customer Service Facilities

In addition to the high voltage transmission line to Soda Springs and 230 kV lines from Soda Springs to Pocatello and other phosphate load centers, BPA also proposed other transmission and customer service facilities to serve Preference Customer loads. These included construction of a 138 kV line extending from Minidoka Dam to the vicinity of Burley and Heyburn to serve "the concentrated loads of the cities of Burley, Heyburn and Rupert and the load of the Raft River Rural Electric Cooperative."

Estimated Cost $51,000,000. Based on experience with GTAs in general, this cost will be split 50-50% between lines and substations for purposes of computing annual costs.

Calculation of Annual Costs for The Ghost Facilities

The total investment by "types" of construction proposed in the BPA study for extending transmission to Southern Idaho for service to Preference Customer load are shown below. It is necessary to break them into types because the annual cost ratios are different for steel tower and wood pole construction.

Estimated Costs:
$149,610,000 (500 kV steel tower)
$ 3,815,000 (115-230 kV wood pole)
$ 25,500,000 (115-138 k V wood pole)
$25,500,000 (unattended substations)
Total $204,425,000

Regarding Annual Cost Ratios:

Annual cost ratios generally include costs for administrative and general, operation and maintenance, and interest and amortization. All of these costs except interest and amortization are subject to inflation.

BPA's 1963 study appears to use an annual cost ratio of approximately 5%, and states that it covers "interest at 2 ½%, amortization over life of equipment, administrative and general expense, direct operation and maintenance, and general plant expense." No further detail is provided. The oldest version of BPA annual cost ratios available to ICUA is 1972. Since 1972 would be very close to when the proposed facilities to serve would have been constructed, ICUA will use the average of BPA's 1999 and 1972 ratios: 9.03% for 500 kV steel lines, 9.86% for 115-230 kV lines, and 11.68% for unattended substations.

The calculation of the annual costs of the Ghost Facilities is as follows:

$149,610,000 (500 kVsteel tower)(0..0716) = $10,712,076
$3,815,000 (115-230 kVwood pole)(0.0802) = $ 305,963
$ 25,500,000 (115-138 kV wood pole)(0.0802)=$2,045,100
$25,500,000 (unattended subs)(0.0964) = $2,458,200
Total $15,521,339/yr.

The estimated annual costs for the "ghost facilities" of the 1960's are $15,521,339/year.

Calculation of the Costs or Benefits

The preliminary Cost-Benefit Report contains the computation of the annual GTA costs and the annual South Idaho Exchange costs. These costs are as follows:

South Idaho GTAs	$6,933,971/year
South Idaho Exch.	$6,375,000/year
Total	$13,308,971/year

Total Estimated Cost of "Ghost Facilities"	$15,521,339/year
Total Forecasted GTA/Exchange Costs	$13,308,971/year
Annual Benefit to BPA	$ 2,212,368/year

IDEA WHITE PAPER

Transmission Options for Delivery
Of IPP Unit-3 Output to IDEA Participants

Background:

IDEA is participating with UAMPS to construct and operate the proposed IPP 900 mw NET, Unit-3 coal plant located in Western Utah. Currently Unite 3 is scheduled for commercial operations in April of 2012. The plant is located in Los Angeles Department of Water and Power's control area which is interconnected to PacifiCorp's and Sierra Pacific Power's control area. All participants in IPP Unit 3 will have to wheel across the Northern Transmission system (NTS) to reach PacifiCorp or Sierra Pacific systems. There are no physical or contractual impediments to the IPP Unit 3 participants' use of the NTS, but there is a wheeling fee that is presently being negotiated.

In order to participate, the IDEA members must be able to take delivery (or a delivery equivalent) of their portion of the Unit 3 output in their service territories. Based on transmission options, there are fout possible groups of participants. The first group consists of participants (and potential participants) that are physically interconnected with PacifiCorp (rocky Mountain Power) in Eastern Idaho and Western Wyoming. The second group is those participants (and potential participants) that are located in Idaho Power's control area in Southern Idaho. The third set of potential are those located in Avista's control area in Northern Idaho, Western Montana and Eastern Washington. The fourth set of participants are those with direct BPA connections in Northern Idaho, Western Montana and Eastern Oregon.

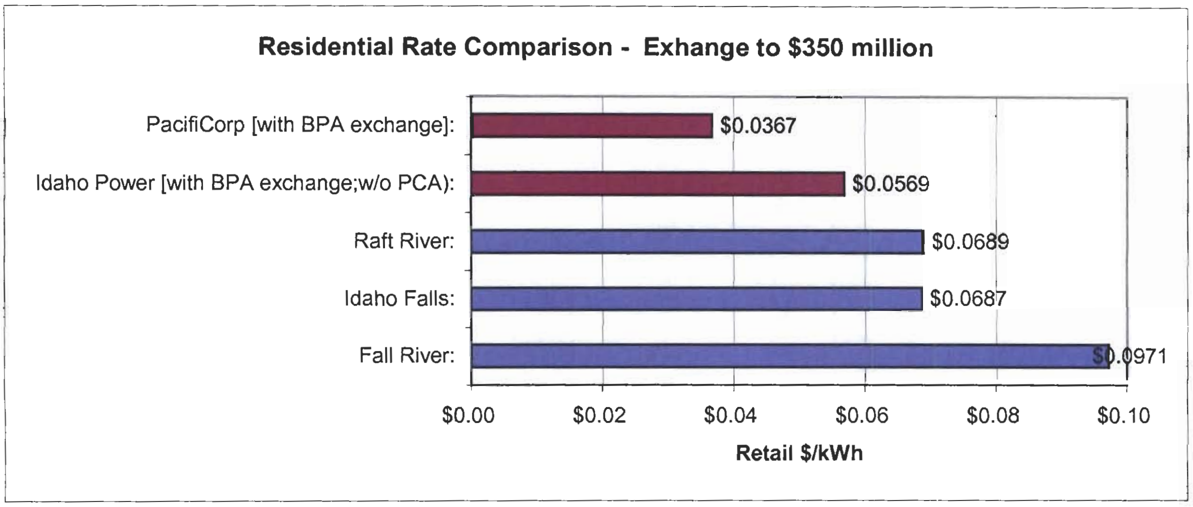
The purpose of this White Paper is to summarize the possible delivery (or delivery equivalent) options in order for all of the relevant players to achieve their goals with the least disruption and in the most economical manner.

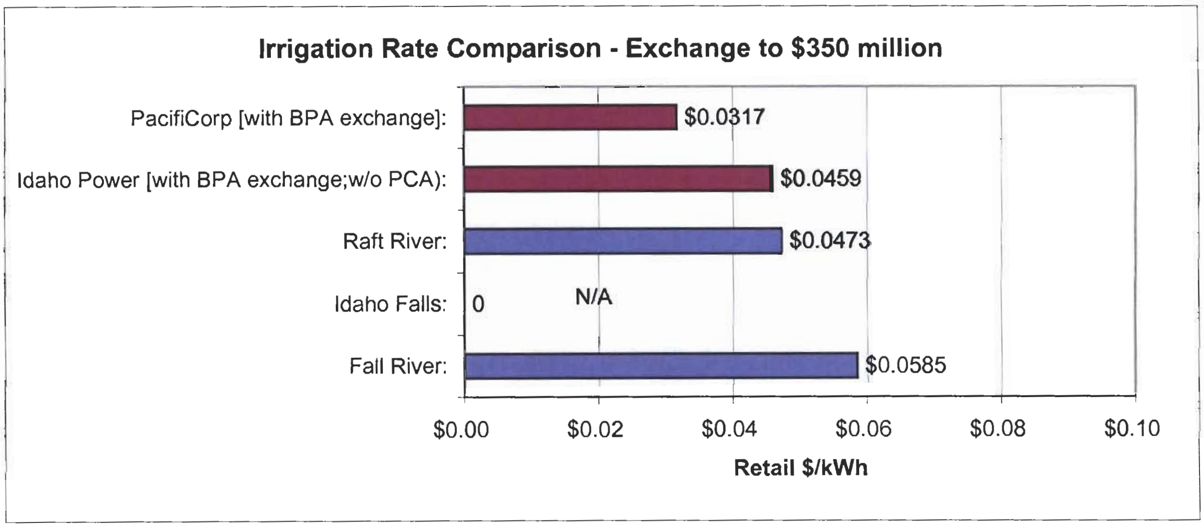
Delivery Options for BPA Customers Participating in IPP Unit 3

Participants are in PAC, IPC, and BPA and Avista control areas. Bonneville has existing transmission arrangements with these control area operators. Bonneville has made a commitment under the Agreement Regarding Transfer Service and the Regional Dialogue Proposal for the delivery of non-federal power. The participants believe that if we provide transmission arrangements to delivery IPP Unit 3 power to Points of Receipt (POR) with theses control areas that the PORs can be added to BPA's current transmission arrangements. Therefore Bonneville should acknowledge responsibility for delivery of IPP Unit 3 power to participants.

We understand there are many details that will have to be worked out to deliver IPP Unit 3 power to the participants. We would like to discuss this delivery option, as well as other options such as displacement or exchanges at other points on the interconnected transmission system that might be of benefit to all parties.

Rate Comparisons Exchange to $350 million $/kWh		
	Residential Rate	Irrigation Rate
Fall River:	$0.0971	$0.0585
Idaho Falls:	$0.0687	N/A
Raft River:	$0.0689	$0.0473
Idaho Power [with BPA exchange;w/o PCA):	$0.0569	$0.0459
PacifiCorp [with BPA exchange]:	$0.0367	$0.0317
PacifiCorp Percent Change	-10.0%	-20.0%

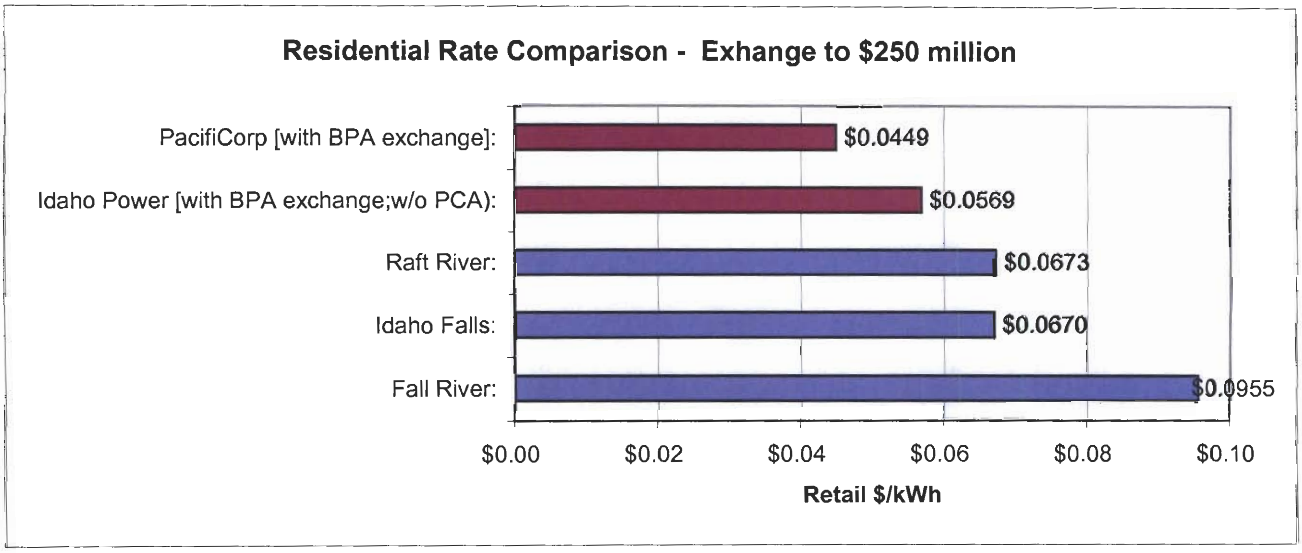


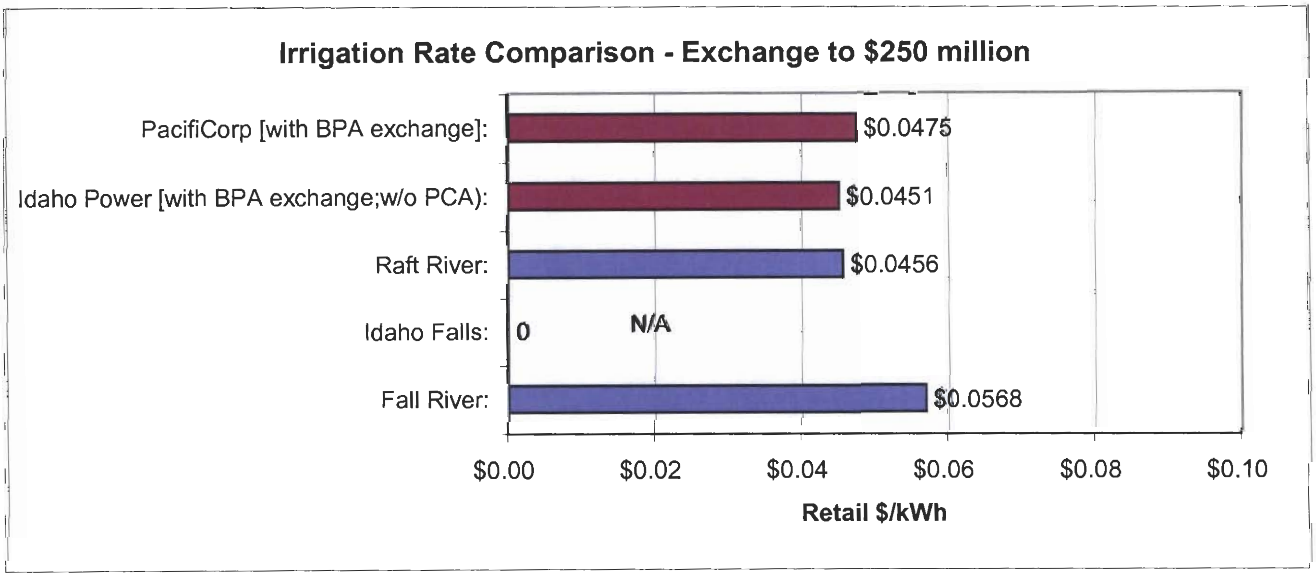


Assumes change in PF Rate passed through to retail customers

EXHIBIT 4 Table 1

Rate Comparisons Exchange to $250 million $/kWh		
	Residential Rate	Irrigation Rate
Fall River:	$0.0955	$0.0568
Idaho Falls:	$0.0670	N/A
Raft River:	$0.0673	$0.0456
Idaho Power [with BPA exchange;w/o PCA):	$0.0569	$0.0451
PacifiCorp [with BPA exchange]:	$0.0449	$0.0475
PacifiCorp Percent Change	10.0%	20.0%

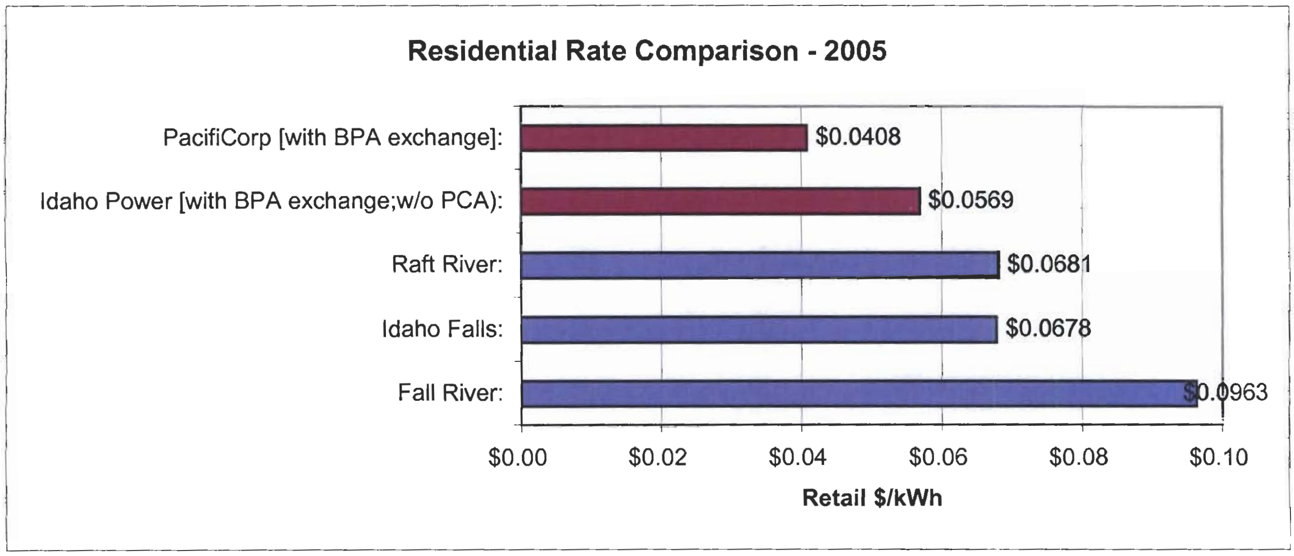




Assumes change in PF Rate passed through to retail customers

EXHIBIT 4 Table 2

Rate Comparisons - 2005 $/kWh		
	Residential Rate	Irrigation Rate
Fall River:	$0.0963	$0.0577
Idaho Falls:	$0.0678	N/A
Raft River:	$0.0681	$0.0464
Idaho Power [with BPA exchange;w/o PCA):	$0.0569	$0.0459
PacifiCorp [with BPA exchange]:	$0.0408	$0.0396



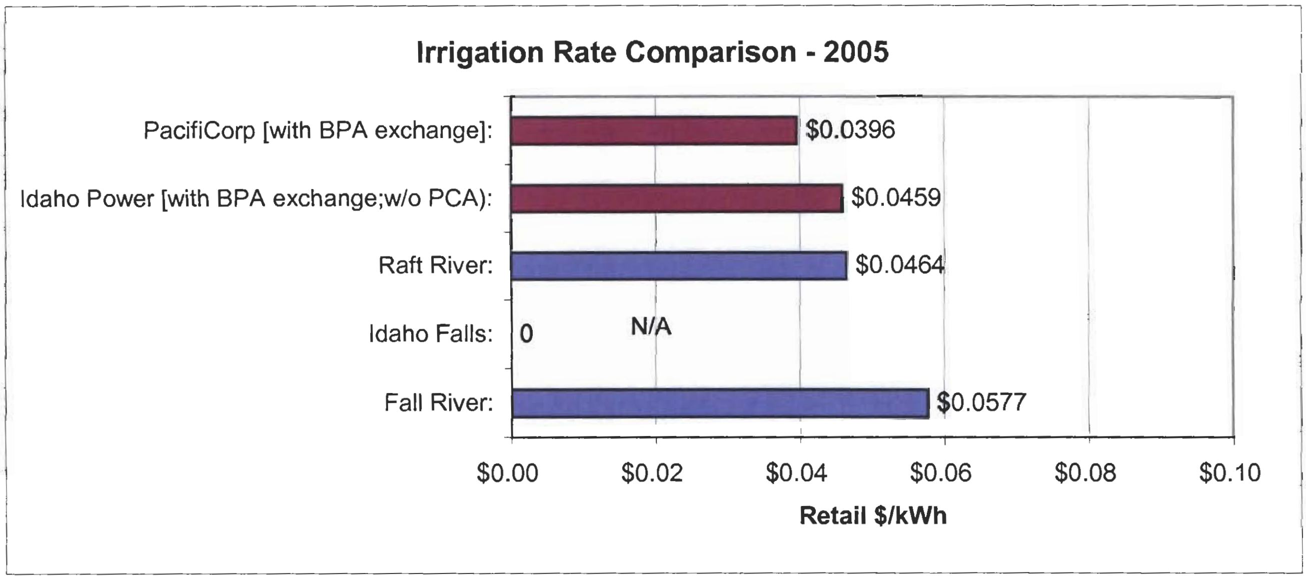


EXHIBIT 4 Table 3

affected by these programs. These programs should be fairly and evenly applied to all customers by using number of meters and not other methods for allocation of benefits.

XII

TIMELINE

We encourage BPA to adhere to its time line and not delay this proceeding as delay will cause uncertainty and increase our risk of not being able to adequately plan for the ultimate allocation of the system.

Respectfully submitted this 31st day of October, 2006.

ICUA

Ed Gossett, President

Ronald L. Williams

Ronald L. Williams, Counsel

IDEA

Jim Webb, President

Peter Richardson, Counsel