APPA

American Public Power Association

2301 M Street, N.W.
Washington, D.C. 20037
202-467-2900; fax: 202-467-2910
www.APPAnet.org

July 8, 2002

The Honorable Sonny Callahan
Chairman
House Appropriations Committee's
Subcommittee on Energy & Water
Development
2362 Rayburn House Office Building
Washington, DC 20515

The Honorable Peter Visclosky
Ranking Minority Member
House Appropriations Committee's
Subcommittee on Energy & Water
Development
2362 Rayburn House Office Building
Washington, DC 20515

Dear Chairman Callahan and Ranking Member Visclosky:

On behalf of public power customers in the Pacific Northwest who receive electric power from the Bonneville Power Administration (BPA), the American Public Power Association (APPA) requests that your subcommittee authorize an increase of $1.3 billion in borrowing authority for BPA in the FY 2003 Energy and Water Development appropriations bill.

Municipally owned systems and public utility districts that are served by BPA are concerned about the possibility of a shortage of both generation and transmission capacity in this section of the country.

The Pacific Northwest is facing a potential shortage of both electricity generation and transmission capacity. As the owner and operator of about 75 percent of the region's high voltage transmission, BPA needs to address these shortages, including construction projects to reinforce the grid, integrate new generation and make federal hydroelectric generation more efficient. These actions will require significant new capital investment, which will exceed BPA's current borrowing authority limit by as early as Fiscal Year 2004. If BPA is to help both the region and the West as a whole avoid the recurrence of the past year's power crisis, the agency requires an immediate increase in its statutory limit of $3.75 billion in Treasury borrowing authority.

As the past year's events have made clear, a combination of changes brought about by wholesale electricity restructuring and load growth throughout the West have increased the use of the transmission system while keeping new investment in the system down. Bonneville had responded by using all the efficiencies, technical upgrades and additions available to carry more electricity through its system. These efficiencies are now in place and the transmission system is operating at or near capacity. With the margin in the system near or at its limit, Bonneville is becoming more concerned with reliability and increased risk of system failure.

In addition, more than 20,000 megawatts of new generation have been proposed in the Northwest, with about 3,000 megawatts already coming online. Bonneville has used all available techniques short of line construction to upgrade the existing transmission system. The grid must be reinforced through new construction to maintain current reliability, to meet new load growth, and to carry the new generation from plant to point of use.

It is also important to note that the proposed regional transmission organization (RTO West) is not expected to begin operation until FY 2004 at the earliest. Meanwhile, construction of a new transmission project takes 3 to 5 years to complete. In any case, under the RTO West proposal the individual transmission system owners such as BPA will continue to be responsible for financing capital construction within their systems. Moreover, for both economic and federal ownership reasons, BPA cannot rely on third party financing as a sure source for investment funding.

This is a matter of vital importance not only to the Pacific Northwest, but also to the entire Western U.S., since BPA's transmission system is essential to the proper functioning of Western electricity markets. APPA requests that you approve a $1.3 billion increase in the FY 2003 bill.

Sincerely,

Alan H. Richardson

Alan H. Richardson
President and CEO

AHR/CE/*go*

cc: Mike Sharp, Senior Legislative Assistant, The Honorable Sonny Callahan

APPA

American Public Power Association

2301 M Street, N.W.
Washington, D.C. 20037
202-467-2900; fax: 202-467-2910
www.APPAnet.org

July 8, 2002

The Honorable Harry Reid
Chairman
Senate Appropriations Committee's
Subcommittee on Energy & Water
Development
129 Dirksen Senate Office Building
Washington, DC 20510

The Honorable Pete Domenici
Ranking Minority Member
Senate Appropriations Committee's
Subcommittee on Energy & Water
Development
129 Dirksen Senate Office Building
Washington, DC 20510

Dear Chairman Reid and Ranking Member Domenici:

On behalf of public power customers in the Pacific Northwest who receive electric power from the Bonneville Power Administration (BPA), the American Public Power Association (APPA) requests that your subcommittee authorize an increase of $1.3 billion in borrowing authority for BPA in the FY 2003 Energy and Water Development appropriations bill.

Municipally owned systems and public utility districts that are served by BPA are concerned about the possibility of a shortage of both generation and transmission capacity in this section of the country.

The Pacific Northwest is facing a potential shortage of both electricity generation and transmission capacity. As the owner and operator of about 75 percent of the region's high voltage transmission, BPA needs to address these shortages, including construction projects to reinforce the grid, integrate new generation and make federal hydroelectric generation more efficient. These actions will require significant new capital investment, which will exceed BPA's current borrowing authority limit by as early as Fiscal Year 2004. If BPA is to help both the region and the West as a whole avoid the recurrence of the past year's power crisis, the agency requires an immediate increase in its statutory limit of $3.75 billion in Treasury borrowing authority.

As the past year's events have made clear, a combination of changes brought about by wholesale electricity restructuring and load growth throughout the West have increased the use of the transmission system while keeping new investment in the system down. Bonneville had responded by using all the efficiencies, technical upgrades and additions available to carry more electricity through its system. These efficiencies are now in place and the transmission system is operating at or near capacity. With the margin in the system near or at its limit, Bonneville is becoming more concerned with reliability and increased risk of system failure.

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It is also important to note that the proposed regional transmission organization (RTO West) is not expected to begin operation until FY 2004 at the earliest. Meanwhile, construction of a new transmission project takes 3 to 5 years to complete. In any case, under the RTO West proposal the individual transmission system owners such as BPA will continue to be responsible for financing capital construction within their systems. Moreover, for both economic and federal ownership reasons, BPA cannot rely on third party financing as a sure source for investment funding.

This is a matter of vital importance not only to the Pacific Northwest, but also to the entire Western U.S., since BPA's transmission system is essential to the proper functioning of Western electricity markets. APPA requests that you approve a $1.3 billion increase in the FY 2003 bill.

Sincerely,

Alan H. Richardson

Alan H. Richardson
President and CEO

AHR/CE/*go*

Jacobson, Carol L - LC-7

From: Majkut, Paul S - LC-7
Sent: Tuesday, December 10, 2002 6:03 PM
To: Jacobson, Carol L - LC-7; Mautner, Paul F - LC-7
Subject: FW: another one

-----Original Message-----
From: Roach, Randy A - L-7
Sent: Tuesday, December 10, 2002 6:01 PM
To: Majkut, Paul S - LC-7
Subject: another one

please see earlier messages

-----Original Message-----
From: Stier, Jeffrey K - KN-DC
Sent: Thursday, August 01, 2002 6:47 AM
To: Majkut, Paul S - LC-7; Roach, Randy A - L-7
Cc: Cohen, Ashley - KN-DC
Subject: FW: amendment attached

http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=107_cong_bills&docid=f:s2784pcs.txt.pdf

Here's the bill link and here's the amendment I insisted upon to Murray/Wyden staff.

-----Original Message-----
From: Stier, Jeffrey K - KN-DC
Sent: Thursday, August 01, 2002 9:43 AM
To: 'Doug_Clapp@murray.senate.gov'; Joshua_Sheinkman@wyden.senate.gov
Subject: RE: amendment attached

Here's what the amendment should say:

In the Senate of the United States -107th Cong., 2d Sess.

S. 2784

Making appropriations for energy and water development for the fiscal year ending September 30, 2003, and for other purposes.

Referred to the Committee on ____________________
and ordered to be printed

Ordered to lie on the table and be printed

Amendment intended to be proposed by Mrs. Murray
Viz:

On page 28, between lines 15 and 16, insert the following:

"For the purposes of providing funds to assist in financing the construction, acquisition, and replacement of the transmission system of the Bonneville Power Administration and to implement the Administrator's authority pursuant to the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839 et seq.) an additional $1,300,000,000 in borrowing authority is made available, under the Federal Columbia River Transmission System Act (16 U.S.C. 838 et. seq.) to remain outstanding at any given time; Provided, that the Bonneville Power Administration shall not use more than $531,000,000 of its permanent borrowing authority in fiscal year 2003."

Please ask Leg. Counsel to review for format purposes only. What they have drafted creates significant problems for us and in any case only provides a $50 million increase in our borrowing authority.

If need be I can put something in the same format that Leg. Counsel used, but I would hope they would draft the amendment the way its author requests.

-----Original Message-----
From: Doug_Clapp@murray.senate.gov [mailto:Doug_Clapp@murray.senate.gov]
Sent: Tuesday, July 30, 2002 5:43 PM
To: Joshua_Sheinkman@wyden.senate.gov; jkstier@bpa.gov
Subject: Fwd:amendment attached

Fellas-
Here is the amendment as drafted by leg counsel. It seems very different from what I sent up.

Majkut, Paul S - LC-7

From: Seifert, Roger - KN-DC
Sent: Friday, July 26, 2002 8:25 AM
To: 'Palmer, William'
Subject: FW: Wyden BPA Borrowing Authority Amendment

Importance: High

Wyden Borrowing Amendment.htm

Per your fast request Bill, her is a copy of the Senate passed Wyden BPA borrowing authority amendment. This amendment was to H.R. 4 with the engrossed amendments of the Senate.

From: Roach, Randy A - L-7
Sent: Tuesday, December 10, 2002 5:54 PM
To: Majkut, Paul S - LC-7
Subject: another item to review

Adobe Acrobat PDF

Please see my last message. What about this?

-----Original Message-----
From: Stier, Jeffrey K - KN-DC
Sent: Wednesday, July 31, 2002 8:15 AM
To: Bennett, Barry - LT-7; Majkut, Paul S - LC-7; Roach, Randy A - L-7
Cc: Seifert, Roger - KN-DC
Subject: FW: amendment attached

I don't know why Senate Leg. Counsel has to do its own thing. Tell me what this needs, please. Thanks.

-----Original Message-----
From: Doug_Clapp@murray.senate.gov [mailto:Doug_Clapp@murray.senate.gov]
Sent: Tuesday, July 30, 2002 5:43 PM
To: Joshua_Sheinkman@wyden.senate.gov; jkstier@bpa.gov
Subject: Fwd:amendment attached

Fellas-
Here is the amendment as drafted by leg counsel. It seems very different from what I sent up.

AMENDMENT NO. ____ Calendar No. ____

Purpose: To increase the borrowing authority of the Bonneville Power Administration.

IN THE SENATE OF THE UNITED STATES—107th Cong., 2d Sess.

S. 2784

Making appropriations for energy and water development for the fiscal year ending September 30, 2003, and for other purposes.

Referred to the Committee on ______________________
and ordered to be printed

Ordered to lie on the table and to be printed

AMENDMENT intended to be proposed by Mrs. MURRAY

Viz:

On page 36, between lines 5 and 6, insert the following:

SEC. 3___. BONNEVILLE POWER ADMINISTRATION BORROWING AUTHORITY.

(a) INCREASE IN BORROWING AUTHORITY.—Section 13 of the Federal Columbia River Transmission System Act (16 U.S.C. 838k) is amended—

(1) by striking the section heading and all that follows through "(a) The Administrator" and inserting the following:

"SEC. 13. REVENUE BONDS.

"(a) ISSUANCE AND SALE.—

"(1) IN GENERAL.—The Administrator"; and

(2) in subsection (a)—

(A) by striking "The aggregate principal amount" and all that follows through "after October 1, 1981" and inserting the following:

"(2) AGGREGATE PRINCIPLE AMOUNT OF BONDS.—

"(A) IN GENERAL.—The aggregate principle amount of any bonds issued and outstanding under paragraph (1) at any 1 time shall not exceed $2,550,000,000.

"(B) SPECIAL AMOUNT.—In addition to the amount under subparagraph (A), the Administrator may issue and sell, and have outstanding at any 1 time, bonds in the aggregate principal amount of $1,250,000,000"; and

(B) by striking "The funds" and inserting the following:

"(3) NOT STATE OR LOCAL FUNDS.—The funds".

(b) LIMITATION.—During fiscal year 2003, the Administrator of the Bonneville Power Administration may issue and sell bonds in the amount of not more than $531,000,000.

Majkut, Paul S - LC-7

From: Roach, Randy A - L-7
Sent: Tuesday, December 10, 2002 6:01 PM
To: Majkut, Paul S - LC-7
Subject: another one

please see earlier messages

-----Original Message-----
From: Stier, Jeffrey K - KN-DC
Sent: Thursday, August 01, 2002 6:47 AM
To: Majkut, Paul S - LC-7; Roach, Randy A - L-7
Cc: Cohen, Ashley - KN-DC
Subject: FW: amendment attached

http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=107_cong_bills&docid=f:s2784pcs.txt.pdf

Here's the bill link and here's the amendment I insisted upon to Murray/Wyden staff.

-----Original Message-----
From: Stier, Jeffrey K - KN-DC
Sent: Thursday, August 01, 2002 9:43 AM
To: 'Doug_Clapp@murray.senate.gov'; Joshua_Sheinkman@wyden.senate.gov
Subject: RE: amendment attached

Here's what the amendment should say:

In the Senate of the United States -107th Cong., 2d Sess.

S. 2784

Making appropriations for energy and water development for the fiscal year ending September 30, 2003, and for other purposes.

Referred to the Committee on ____________________
and ordered to be printed

Ordered to lie on the table and be printed

Amendment intended to be proposed by Mrs. Murray
Viz:

On page 28, between lines 15 and 16, insert the following:

"For the purposes of providing funds to assist in financing the construction, acquisition, and replacement of the transmission system of the Bonneville Power Administration and to implement the Administrator's authority pursuant to the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839 et seq.) an additional $1,300,000,000 in borrowing authority is made available, under the Federal Columbia River Transmission System Act (16 U.S.C. 838 et. seq.) to remain outstanding at any given time; Provided, that the Bonneville Power Administration shall not use more than $531,000,000 of its permanent borrowing authority in fiscal year 2003."

Please ask Leg. Counsel to review for format purposes only. What they have drafted creates significant problems for us and in any case only provides a $50 million increase in our borrowing authority.

If need be I can put something in the same format that Leg. Counsel used, but I would hope they would draft the amendment the way its author requests.

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From: Doug_Clapp@murray.senate.gov [mailto:Doug_Clapp@murray.senate.gov]
Sent: Tuesday, July 30, 2002 5:43 PM
To: Joshua_Sheinkman@wyden.senate.gov; jkstier@bpa.gov
Subject: Fwd:amendment attached

Fellas-
Here is the amendment as drafted by leg counsel. It seems very different from what I sent up.

Majkut, Paul S - LC-7

From: Seifert, Roger - KN-DC
Sent: Friday, July 26, 2002 8:20 AM
To: 'Palmer, William'
Cc: Stier, Jeffrey K - KN-DC; Curtis, Jim - DF-2; Hawken, Mary - DFF-2; Roach, Randy A - L-7; Majkut, Paul S - LC-7
Subject: Wyden BPA Borrowing Authority Amendment

Attached is an electronic copy of the technical fixes to the Senate Legislative Council drafted Wyden Amendment that we suggested at the time the bill was being considered. As I have indicated several previous times we were trying to keep our Treasury borrowing relationship (to Treasury and not direct to market) as it has historically been. As I have also indicated previously, I have also had several conversations with Paula Farrell to assure her we wanted to do that, but were not successful. Since you asked for the Senate passed Wyden Amendment, Jeff and I wanted you to have these needed changes to avoid changing our relationship with Treasury and how our borrowing interest rates are determined.

Borrowing Authority Increase.d...

SA 3230. Mr. WYDEN submitted an amendment intended to be proposed to amendment SA 2917 proposed by Mr. DASCHLE (for himself and Mr. BINGAMAN) to the bill (S. 517) to authorize funding the Department of Energy to enhance its mission areas through technology transfer and partnerships for fiscal years 2002 through 2006, and for other purposes; which was ordered to lie on the table; as follows:

On page 62, between lines 3 and 4, insert the following:

SEC. 2__. BONNEVILLE POWER ADMINISTRATION BONDS.

Section 13 of the Federal Columbia River Transmission System Act (16 U.S.C. 838k) is amended--

(1) by striking the section heading and all that follows through ``(a) The Administrator'' and inserting the following:

``SEC. 13. BONNEVILLE POWER ADMINISTRATION BONDS.

``(a) **BONDS**.--

``(1) **IN GENERAL**.--The Administrator''; and

(2) by adding at the end the following:

``(2) **ADDITIONAL BORROWING AUTHORITY**.--In addition to the borrowing authority of the Administrator authorized under paragraph (1) or any other provision of law, an additional $1,300,000,000 is made available, as provided in this section, to remain outstanding at any ~~1~~ one time--

``(A) to provide funds to assist in financing the construction, acquisition, and replacement of the transmission system of the Bonneville Power Administration; and

``(B) to implement the authorities of the Administrator under the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839 et seq.).''.

PG&E Corporation

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG #[redacted]
RECEIPT DATE:
6.28.01
DUE DATE:
INFO ONLY

Steven L. Kline
Vice President
Federal Governmental &
Regulatory Relations

700 11th Street NW, Suite 250
Washington, DC 20001
202.638.3500
Fax: 202.638.3522
Internet: steven.kline@pge-corp.com

June 25, 2001

The Honorable Spencer Abraham
Secretary of Energy
1000 Independence Ave.
Washington, DC 20585-0001

INFO ONLY: Kip Moxness-TM/Ditt2
cc: A-7, D-7, KN/Wash, L-7, P-6, T/Ditt2, DF-2, Scott Wilson-PT-5

Dear Secretary Abraham:

I am writing today to express PG&E Corporation's support for efforts by the Bonneville Power Administration (BPA) to improve its ability to deliver power in the West. Specifically, we would like to endorse BPA's request for additional federal borrowing authority to finance transmission construction.

As you know, significant progress has been made toward returning to supply/demand balance in the West. PG&E Corporation's National Energy Group is contributing to this effort. Currently, we have more than 4,000 megawatts in construction or development in the region, and we continue to look at potential sites. We also are upgrading our natural gas pipeline infrastructure to help ensure the new plants are fueled.

As new generating projects begin to come on line, the situation in the West undoubtedly will improve from both a supply and price stability perspective. But to get that power to market, we must improve the region's aging transmission systems. And we must begin that effort now so that the transmission capacity is ready when the generating capacity becomes available.

BPA operates one of the most important transmission systems in the West. Because of the broad interconnectedness of the Western System Coordinating Council grid, the ability of BPA to deliver power from Northwest facilities impacts reliability throughout the region. That said, we are very concerned that BPA's transmission system is not prepared to accommodate the new generating facilities now in development or construction in the Northwest.

We understand BPA is seeking to extend its federal borrowing authority so that it has financial means to make critically needed transmission upgrades. We support this effort as an important component of the overall effort to solve the West's energy problems. We also strongly urge BPA to begin immediately planning for transmission upgrades in the most critical corridors. Priority should be given to transmission serving areas where advance plant construction and development are underway. We are concerned that projects ready for construction cannot get a commitment from BPA to provide transmission service coincident with the completion of construction.

As always, Mr. Secretary, we greatly appreciate your attention to the issues in the West and your commitment to working with the region to address the many challenges facing us.

Please don't hesitate to call me at any time if I can be of assistance to you.

Sincerely,

cc: Mr. Steven Wright ✓

Folder Profile

Control # 2001-016257

Name: Letter to Secretary Spencer Abraham from the Honorable G

Priority: Essential Critical

Folder Trigger: Letter

DOE Addressee: Spencer Abraham

Source: SO

Date Received: 7/9/01

Subject Text: Governor Gary Locke, State of Washington, urges the Secretary to support the BPA's request to increase its borrowing authority from the U.S. Treasury and within the Administration and before Congress

Correspondence Date: 7/6/01

RIDS Information: Head of Agency

Sensitivity: Not Applicable

Action Office #:

Classification: None

Signature/Approval: Spencer Abraham

Point of Contact: CARPENTC

Organization ID: EXECCORR2

Action Requested: Prepare Response

Assigned To: BPA

Special Instructions: CI concurrence required.

Date Due: 7/18/01

Date Completed:

PRIORITY

RECEIVED BY BPA ADMINISTRATOR'S OFC-LOG #: 01-0344
RECEIPT DATE: 7-10-01
DUE DATE: 7-20-01

Assign: KR-7-C
cc: A, D, KN, KR, DF, P, T

2001-016257 7/9 A 10:53

GARY LOCKE
Governor

STATE OF WASHINGTON
OFFICE OF THE GOVERNOR
P.O. Box 40002 • Olympia, Washington 98504-0002 • (360) 753-6780 • TTY/TDD (360) 753-6466

July 6, 2001

The Honorable Spencer Abraham
Secretary of Energy
United States Department of Energy
James Forrestal Building
1000 Independence Avenue S.W.
Washington, D.C. 20585

Dear Secretary Abraham:

I am writing to express my strong support for the Bonneville Power Administration's (BPA's) request to increase its borrowing authority from the U.S. Treasury.

BPA estimates that it will need approximately $2 billion in additional authority to help finance new capital investment for transmission, generation and conservation. Because BPA is such an integral part of both the generation and the transmission system in the Pacific Northwest, it is critical that BPA have sufficient borrowing authority to ensure that these infrastructure improvements are made in a timely manner.

BPA's transmission system accounts for about 75 percent of the high voltage transmission in the Pacific Northwest. It is now at or near capacity. Additional transmission capacity is needed to allow for the integration of the new generation being proposed for the Northwest. BPA needs to make increased capital investments soon to handle this new generation and preserve the reliability of the current transmission system.

In addition, the Federal Columbia River Power System contributes about 40 percent of the region's firm energy. Many of these hydroelectric facilities are more than 40 years old and need updates and improvements to maximize their efficiency. With increased investment in these facilities it will be possible to increase generation capability by as much as 300 average megawatts. The investments in system efficiencies surely will return more than the cost of capital.

For these reasons, I urge you to support BPA's request within the Administration and before Congress. Thank you for your attention to this matter.

Sincerely,

Gary Locke
Governor

PSE PUGET SOUND ENERGY

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG #:01-0366
RECEIPT DATE:
7-12-01
DUE DATE: INFO ONLY

A, D, KN, DF, L P T

July 12, 2001

Chairman Robert C. Byrd
Senate Committee on Appropriations
311 Senate Hart Office Building
Washington, DC 20510

Dear Chairman Byrd:

I am writing to express Puget Sound Energy, Inc.'s support for increasing the borrowing authority of the Bonneville Power Administration (BPA) to facilitate the construction of additional electric transmission facilities. This funding is critically important to improve the capacity and reliability of BPA's transmission system for the benefit of consumers throughout the Pacific Northwest.

I am pleased that BPA has recently agreed to form a review committee so that its transmission customers can be assured that transmission improvements are economically justified and prioritized so as to provide the most cost-effective and reliable service for the region. Puget Sound Energy will gladly participate in the important work to be undertaken by this review committee. It would be appropriate for language supporting the formation of this committee to be included in your Committee report.

If you or your staff have any questions about Puget Sound Energy's support for additional BPA borrowing authority, please contact Bill Gaines, Puget Sound Energy's Vice President, Energy Supply at (425) 462-3145.

Sincerely,

William S. Weaver
President and Chief Executive Officer

cc: Secretary Spencer Abraham
Senator Patty Murray
Stephen Wright – Acting Administrator, BPA

ALAN RICHARDSON
Chairman

825 N.E. Multnomah, Suite 2000
Portland, Oregon 97232-4116
(503) 813-6765
FAX (503) 813-7109

:CEIVED BY BPA
:MINISTRATOR'S
C-LOG #: 01-0367
:CEIPT DATE:
7-12-01
UE DATE: INFO ONLY

A, D, KN, DF, L, P, T

PACIFICORP

July 11, 2001

The Honorable Robert C. Byrd
Chairman, Committee on Appropriations
United States Senate
Washington, D.C. 20510

Dear Senator Byrd:

PacifiCorp supports an increase in borrowing authority for the Bonneville Power Administration (BPA) as part of H.R. 2311, the Fiscal Year 2002 Energy and Water Appropriations that may be considered by your Committee July 12, 2001.

PacifiCorp is an investor-owned utility serving 1.5 million retail electric consumers in six western states.

By permitting Bonneville to make additional investments in its transmission network, this increase in borrowing authority would represent a critical step toward needed improvements in the capacity and reliability of BPA's transmission system. Such investments need to be made for the benefit of all electric consumers throughout the Pacific Northwest and, indirectly, the entire west.

Bonneville has agreed to form a technical review committee with its transmission customers to help assure that transmission improvements are prioritized to provide the most cost-effective and reliable service for the region. We respectfully request the Report accompanying the Committee's action on H.R. 2311 reflect positively on the formation of this committee.

Thank you for your consideration of our request.

Sincerely,

Alan V. Richardson
Chairman of the Board

Cc: The Honorable Ted Stevens
The Honorable Harry Reid
The Honorable Pet V. Domenici
The Honorable Patty Murray
The Honorable Larry E. Craig
Steve Wright, BPA

Avista Corp. Idaho Power Company Montana Power Company PacifiCorp Portland General Electric Puget Sound Energy

Northwest Investor Owned Utilities

July 11, 2001

Chairman Robert C. Byrd
Senate Committee on Appropriations
311 Senate Hart Office Building
Washington, DC 20510

Dear Chairman Byrd:

On behalf of Avista Corporation, Idaho Power Company, Montana Power Company, PacifiCorp, Portland General Electric, and Puget Sound Energy, Inc., I am writing to voice our strong support for increasing the borrowing authority of the Bonneville Power Administration (BPA) as part of the Energy and Water Appropriations bill that will be considered by your Committee tomorrow. We believe that this is a critical step toward improving the capacity and reliability of BPA's transmission system, for the benefit of consumers throughout the Pacific Northwest. We are pleased to inform you that BPA has recently agreed to form a technical review committee with its transmission customers to assure that transmission improvements are prioritized so as to provide the most cost-effective and reliable service for the region. We respectfully request that language in support of the formation of this committee be included in your Committee report.

If you or your staff have any questions, please feel free to call me.

Sincerely,

James Litchfield
Consultant for the
Investor Owned Utilities
503-222-9480
lcg@europa.com

EIVED BY BPA
INISTRATOR'S
-LOG #:01-0368
RECEIPT DATE:
7-12-01
E DATE:
INFO ONLY
A, D, KN, DF, L, P, T

cc: Senator Ted Stevens
Senator Jack Reed
Senator Pete Domenici
Senator Patty Murray
Senator Conrad Burns
Rep. Sonny Callahan
Rep. Peter Visclosky
Secretary Spencer Abraham
Stephen Wright – Acting Administrator, Bonneville Power Administration

PGE

Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-8401 • Fax (503) 778-5566

Peggy Y. Fowler
CEO and President

RECEIVED BY BPA ADMINISTRATOR'S OFC-LOG #: 01-0371
RECEIPT DATE: 7-13-01
DUE DATE:
INFO ONLY
Info Only: A, D, KN, DF, L, P, T

July 12, 2001

Chairman Robert C. Byrd
Senate Committee on Appropriations
311 Senate Hart Office Building
Washington, DC 20510

Dear Chairman Byrd:

I am writing to express Portland General Electric Company's support for increasing the transmission borrowing authority of the Bonneville Power Administration (BPA) as part of the Energy and Water Appropriations bill. We believe that this is a critical step toward improving the capacity and reliability of the transmission system for the benefit of consumers throughout the Pacific Northwest. We are also pleased BPA has agreed to form a technical review committee with its transmission customers to assure that transmission improvements are prioritized to provide the most cost-effective and reliable service for the region.

We look forward to working cooperatively with BPA to review proposed capital projects and helping assure dependable transmission in the region. We respectfully request that language in support of the formation of this committee be included in your Committee report.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Peggy Fowler

cc: Steve Wright, BPA - Acting Administrator and CEO
Jeff Stier, BPA - Vice President
Secretary of Energy Spencer Abraham
Senator Patty Murray
Senator Gordon Smith
Senator Ron Wyden
Michael A. Andrews, Vinson and Elkins

PUBLIC SERVICE COMMISSION

1701 Prospect Avenue • PO Box 202601
Helena, Montana 59620-2601
Telephone: (406) 444-6166
FAX #: (406) 444-7618
E-MAIL: gfeland@state.mt.us

Gary Feland, Commissioner
District 1

July 12, 2001

Secretary Spencer Abraham
Room 7B22
1000 Independence Avenue
Washington, D.C. 20585

Post-it® Fax Note 7671	Date 16 Jul 01 # of pages ▸ 1
To Karen Hunt	From Gail Kuntz
Co./Dept. Steve Wright	Co. BPA-MSGL
Phone #	Phone # 406 449 5790
Fax # 503-230-4018	Fax #

Dear Secretary Abraham:

On behalf of the Montana Public Service Commission, I am writing to express support for the Bonneville Power Administration's (BPA) request for an increase in its borrowing authority from the U.S. Treasury. BPA estimates its need for the development of a package of infrastructure improvements at approximately two (2) billion dollars in additional borrowing authority.

Inadequate electrical generation and transmission infrastructure has been one of the fundamental causes of the electricity price crisis we are experiencing in the west. If new generation and transmission are to be built anytime soon, BPA will necessarily play a vital role.

BPA must make significant capital investments in its high voltage transmission system in the Pacific Northwest to serve its load. New generation is being built, and significantly more is scheduled for construction. However, unless BPA can integrate this new production into its system it may not be built.

BPA must also support newly developing efficiency technologies as they become financially viable to encourage consumers to make critical conservation and demand side management investments. Investment in conservation helps supplant costly power purchases, and because it involves private interests, creates additional jobs in the private sector.

Some of the transmission infrastructure enhancement proposed by BPA will affect the wholesale electricity market in Montana. Therefore, the Commission's support for an increase in BPA's borrowing authority is conditioned on the opportunity of Montana to participate in the decision making process for the various projects that BPA proposes.

Thank you for your consideration.

Sincerely,

Gary Feland
Chairman

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG #: 01-0381
RECEIPT DATE:
7-17-01
DUE DATE: INFO ONLY

INFO ONLY: Gail Kuntz-KR/MSGL
cc: A-7, D-7, KN/Wash, KR-7, L-7, P-6, PG-5, KE-4, DF-2, T/Ditt2

PG&E Corporation

Steven L. Kline
Vice President
Federal Governmental &
Regulatory Relations

700 11th Street NW, Suite 250
Washington, DC 20001
202.638.3500
Fax: 202.638.3522
Internet: steven.kline@pge-corp.com

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG #: 01.0373
RECEIPT DATE:
7.16.01
DUE DATE:
INFO ONLY

July 11, 2001

Honorable Mitchell E. Daniels, Jr.
Director
Office of Management & Budget
Eisenhower Executive Office Building
17th & Pennsylvania Avenue, NW
Washington DC, 20503

INFO ONLY: A-7, D-7, KN/Wash, L-7, P-6, T/Ditt2, DF-2

Dear Director Daniels:

I am writing to express PG&E Corporation's support for efforts to improve the Bonneville Power Administration's (BPA) ability to deliver electricity in the West. Specifically, we endorse the request for additional federal borrowing authority to allow BPA to finance transmission construction.

Significant progress has been made toward returning to a balance in electricity supply and demand in the West. PG&E Corporation's National Energy Group is contributing to this effort. Currently, we have more than 4,000 megawatts of electric generation in construction or development in the region, and we continue to look at potential plant sites. We also are upgrading our natural gas pipeline infrastructure to help ensure the new plants are fueled.

As new generating projects begin to come on line, the situation in the West undoubtedly will improve from both a supply and price stability perspective. But to get that power to market, we must improve the region's aging transmission systems. We must begin that effort now so that the transmission capacity is ready when the generating capacity becomes available.

As you know, BPA operates one of the most important transmission systems in the West. Because of the broad interconnectedness of the Western System Coordinating Council grid, the ability of BPA to deliver power from Northwest facilities impacts reliability throughout the region. That said, we are very concerned that BPA's transmission system is not prepared to accommodate the new generating facilities now in development or construction in the Northwest.

We understand BPA needs to extend its federal borrowing authority so that it has the financial means to make critically needed transmission upgrades. We support this effort as an important component of the overall effort to solve the West's energy problems. We also strongly urge Bonneville to begin immediately to plan for transmission upgrades in the most critical corridors. Priority should be given to transmission serving areas where advance plant construction and development are underway in order that plants ready for construction can be assured that BPA will provide transmission service coincident with their completion.

Please don't hesitate to call me at any time if I can be of assistance to you.

Sincerely,

cc: Mr. Stephen Wright
Honorable Harry Reid
Honorable Pete Domenici
Honorable Larry Craig
Honorable Conrad Burns
Honorable Diane Feinstein

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG #: 01-0375

RECEIPT DATE:
7.16.01

DUE DATE:
INFO ONLY

Avista Corp.
1411 East Mission MSC-12 PO Box 3727
Spokane, Washington 99220-3727
Telephone 509-489-0500

Gary G. Ely
Chairman of the Board,
President and Chief Executive Officer

AVISTA Corp.

July 11, 2001

INFO ONLY: A-7, D-7, KN/Wash, L-7, P-6, T/Ditt2, DF-2

Chairman Robert C. Byrd
Senate Committee on Appropriations
311 Senate Hart Office Building
Washington, DC 20510

Dear Chairman Byrd:

On behalf of Avista Corporation, I am writing to follow-up on the July 11 letter you received from Jim Litchfield regarding the strong support of the Northwest investor-owned utilities for increasing the borrowing authority of the Bonneville Power Administration (BPA) as part of the Energy and Water Appropriations bill.

Avista supports increasing BPA's borrowing authority because of the critical need to improve the BPA transmission system. The BPA transmission system is the "backbone" of the region's transmission grid, but it has not been significantly expanded for at least 10 years. Consequently, BPA does not have sufficient transmission capacity to accommodate power from all of the current and pending generation facilities that are needed to satisfy the energy needs of the Northwest. Unless a substantial investment is made in upgrading the BPA transmission system in the very near future, we run a substantial risk of serious reliability problems in the region.

I am particularly pleased that BPA has agreed to form a technical and economical review committee with its transmission customers. We look forward to working with BPA to assure that its transmission improvements are prioritized so as to provide the most cost-effective and reliable service for the region.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Gary Ely

cc: Senator Ted Stevens
Senator Jack Reed
Senator Pete Domenici
Senator Patty Murray
Senator Conrad Burns
Rep. Sonny Callahan
Rep. Peter Visclosky
Secretary Spencer Abraham
Stephen Wright – Acting Administrator, Bonneville Power Administration

07/16/2001 MON 14:08 FAX 202 586 6762 →→→ ADMIN-CEO OFFICE ☑002/003
JUL.16.2001 10:10AM NO.223 P.2/3

RECEIVED BY BPA ADMINISTRATOR'S
OFC LOG # [redacted]
RECEIPT DATE 7/16/01
DUE DATE:
INFO ONLY

United States Senate

WASHINGTON, DC 20510

July 12, 2001

The Honorable Mitch Daniels
Director
Office of Management and Budget
Old Executive Office Building
Washington, D.C. 20503

INFO ONLY: KR-7C
cc: A-7, D-7, KN/Wash, L-7, P-6, KE-4, T/Ditt2, DF-2

Dear Director Daniels:

We are writing with regard to two issues of vital importance to our region: the Bonneville Power Administration's access to credits under section 4(h)(10)(C) of the Northwest Power Act and BPA's need for an increase in its authority to sell bonds to the U.S. Treasury.

Under the Northwest Power Act, BPA is required to make expenditures to protect, mitigate, and enhance fish and wildlife affected by Federal hydro projects. BPA is required to do so consistent with the fish and wildlife program of the Northwest Power Planning Council (Council). The Act also requires BPA to take as a credit against its debt repayments to Treasury the non-power project purposes' share of BPA's fish and wildlife costs. In effect, section 4(h)(10)(C) of the Act directs BPA – acting on behalf of its ratepayers – to appropriately allocate to the U.S. Treasury its share of the mitigation costs for these Federal projects.

Due to the persistent drought in the Northwest and the extraordinarily high wholesale power market prices in the West, fish and wildlife mitigation costs in the Columbia River basin have increased dramatically this year. Therefore, the 4(h)(10)(C) credits also have increased significantly. BPA's access to the credits is currently implemented by reducing annual cash transfers to Treasury. The credits do not reduce BPA's payment obligation; rather the credits are treated as a source of funds that satisfies the payment obligation. It is essential that the Administration support Bonneville's access to credits for this year's salmon recovery costs, as well as credits that are supposed to be made available under adverse water conditions through the Fish Cost Contingency Fund established in 1996.

The second issue of importance, BPA's need for an increase in its authority to sell bonds to the U.S. Treasury, is driven by system improvements BPA must make to maintain the reliability of the Northwest's electricity supply and relieve crippling transmission system congestion. In addition, Bonneville is being called upon to integrate a substantial amount of new generation now being planned by private developers in the region. Finally, BPA has identified investments it can make using its self-financing authority to increase generation from existing facilities within the Federal Columbia River Power System, and to step up regional energy conservation efforts. To assure that BPA continues to have sufficient financial resources necessary to make needed electric infrastructure investments in a timely manner, BPA will need up to $2 billion in additional borrowing authority above the current $3.75 billion limit.

We want to impress upon you the importance of these two issues. The Northwest's economy and our natural environment depend on BPA's ability to secure its access to the credits and the additional borrowing authority.

Sincerely,

Gordon H. Smith
United States Senate

Maria Cantwell
United States Senate

Ron Wyden
United States Senate

Larry Craig
United States Senate

Patty Murray
United States Senate

Max Baucus
United States Senate

Mike Crapo
United States Senate

Conrad Burns
United States Senate

NORTHWEST POWER PLANNING COUNCIL

851 S.W. SIXTH AVENUE, SUITE 1100
PORTLAND, OREGON 97204-1348

Fax: 503-820-2370
Phone: 503-222-5161
1-800-452-5161
Internet: www.nwcouncil.org

ECEIVED BY BPA
DMINISTRATOR'S
FC-LOG #:[redacted]
ECEIPT DATE:
7·16·01
DUE DATE:
INFO ONLY

July 6, 2001

The Honorable Spencer Abraham
Secretary of Energy
U.S. Department of Energy
Forrestal Building 1000 Independence Avenue, S.W.
Washington, D.C. 20585

INFO ONLY: KR-7
cc: A-7, D-7, KN/Wash, KR-7C, L-7, P-6, PG-5, KE-4, DF-2, T/Ditt2

Dear Secretary Abraham:

The Northwest Power Planning Council supports the Bonneville Power Administration's request for additional Federal Treasury borrowing authority for capital improvements to the Federal Columbia River Power System (FCRPS). Needed upgrades and improvements to the high-voltage transmission system, hydroelectric facilities and energy conservation program will require Bonneville to have access to additional capital funds in the near-term.

In particular, this year's West Coast electricity crisis has helped underscore serious constraints and deficiencies within the transmission system. The system is currently operating at or near full capacity, and is under increasing stress. The robust activity in the wholesale power market is pressuring Bonneville to run the system harder and for patterns of transactions for which it was not designed. This is making it more difficult to schedule maintenance and construction activities. In addition, there is serious concern that the transmission system will not have the capacity necessary to handle the new generation in the Northwest that is needed to bring supply and demand back into balance. Bonneville's access to additional borrowing authority is necessary to ensure long-term system reliability for the Northwest and the entire West Coast.

The Council also supports additional borrowing authority for improvements, additions and replacements at hydroelectric facilities within the FCRPS and the fishery mitigation projects associated with them. In 1992, Congress gave Bonneville the authority to enter into direct funding agreements with the Corps of Engineers and the Bureau of Reclamation for upgrades at their hydroelectric projects. Bonneville has a similar direct funding agreement with the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan hatcheries. These agreements preclude the need for congressional appropriations for these activities, but increase Bonneville's capital borrowing requirements. The Council recognizes this need and supports new borrowing authority to increase the efficiency and reliability of the FCRPS and minimize system impacts on fish and wildlife.

The electricity crisis has also highlighted the importance of vigorous and sustained energy conservation efforts in the Northwest. Unfortunately, during the 1990s, Bonneville's level of investment in conservation decreased substantially due to the emerging competitive electricity market and financial uncertainties. The consequences of this change in policy have been exposed by the astonishingly high electricity prices that we've experienced this past year. Accordingly, it is important that Bonneville regain its leadership in assisting regional utilities and other customers to invest in cost-effective conservation measures while recognizing the market realities of the evolving wholesale power supply market. Additional borrowing authority will allow Bonneville to stimulate such investments throughout the Northwest.

The Council believes that increases in borrowing authority should be accompanied by a high level of accountability in the utilization of the funds. Because the electric ratepayers of the region repay these investments, and because the transmission system supports transactions by several non-federal entities, there is a need to ensure adequate regional participation and oversight in the projects pursued. An open, independent process should be established that identifies least-cost solutions and prioritizes investments that result in a completion schedule of projects. The results of such a process should be included in Bonneville's annual budget submittal for an additional level of accountability. The Council is available to participate in such a process in any way deemed appropriate by the regional entities.

Thank you for your attention to his matter, and please do not hesitate to contact me if you have any questions or comments.

Sincerely,

Frank L. Cassidy, Jr.
Chair

Identical letter sent to: The Honorable Spencer Abraham, Secretary of Energy
Members of the Northwest congressional delegation
House and Senate Committees on Appropriations

NORTHWEST POWER PLANNING COUNCIL

851 S.W. SIXTH AVENUE, SUITE 1100
PORTLAND, OREGON 97204-1348

Fax: 503-820-2370
Phone: 503-222-5161 1-800-452-5161
Internet: www.nwcouncil.org

RECEIVED BY BPA ADMINISTRATOR'S OFC-LOG # [redacted]
RECEIPT DATE: 7·16·01
DUE DATE:
INFO ONLY

July 6, 2001

The Honorable Patty Murray
United States Senate
173 Russell Senate Office Building
Washington, D.C. 20510-4704

INFO ONLY: KR-7
cc: A-7, D-7, KN/Wash, KR-7C, L-7, P-6, PG-5, KE-4, DF-2, T/Ditt2

Dear Senator Murray:

The Northwest Power Planning Council supports the Bonneville Power Administration's request for additional Federal Treasury borrowing authority for capital improvements to the Federal Columbia River Power System (FCRPS). Needed upgrades and improvements to the high-voltage transmission system, hydroelectric facilities and energy conservation program will require Bonneville to have access to additional capital funds in the near-term.

In particular, this year's West Coast electricity crisis has helped underscore serious constraints and deficiencies within the transmission system. The system is currently operating at or near full capacity, and is under increasing stress. The robust activity in the wholesale power market is pressuring Bonneville to run the system harder and for patterns of transactions for which it was not designed. This is making it more difficult to schedule maintenance and construction activities. In addition, there is serious concern that the transmission system will not have the capacity necessary to handle the new generation in the Northwest that is needed to bring supply and demand back into balance. Bonneville's access to additional borrowing authority is necessary to ensure long-term system reliability for the Northwest and the entire West Coast.

The Council also supports additional borrowing authority for improvements, additions and replacements at hydroelectric facilities within the FCRPS and the fishery mitigation projects associated with them. In 1992, Congress gave Bonneville the authority to enter into direct funding agreements with the Corps of Engineers and the Bureau of Reclamation for upgrades at their hydroelectric projects. Bonneville has a similar direct funding agreement with the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan hatcheries. These agreements preclude the need for congressional appropriations for these activities, but increase Bonneville's capital borrowing requirements. The Council recognizes this need and supports new borrowing authority to increase the efficiency and reliability of the FCRPS and minimize system impacts on fish and wildlife.

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The Council believes that increases in borrowing authority should be accompanied by a high level of accountability in the utilization of the funds. Because the electric ratepayers of the region repay these investments, and because the transmission system supports transactions by several non-federal entities, there is a need to ensure adequate regional participation and oversight in the projects pursued. An open, independent process should be established that identifies least-cost solutions and prioritizes investments that result in a completion schedule of projects. The results of such a process should be included in Bonneville's annual budget submittal for an additional level of accountability. The Council is available to participate in such a process in any way deemed appropriate by the regional entities.

Thank you for your attention to his matter, and please do not hesitate to contact me if you have any questions or comments.

Sincerely,

Frank L. Cassidy, Jr.
Chair

Identical letter sent to: The Honorable Spencer Abraham, Secretary of Energy
Members of the Northwest congressional delegation
House and Senate Committees on Appropriations

STATE OF WASHINGTON

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

1300 S. Evergreen Park Dr. S.W., P.O. Box 47250 • Olympia, Washington 98504-7250

(360) 664-1160 • TTY (360) 586-8203

July 11, 2001

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG #: 01-0379
RECEIPT DATE:
7·16·01
DUE DATE:
INFO ONLY

INFO ONLY: A-7, D-7, KN/Wash, L-7, P-6, PG-5, KE-4, DF-2, T/Ditt2, Cindy Custer-KR/WSGL

The Honorable Spencer Abraham, Secretary
Department of Energy
Forrestal Building
1000 Independence Ave. SW
Washington D.C. 20585

Dear Secretary Abraham:

We write to express our support for the Bonneville Power Administration's (BPA) request for an increase to its borrowing authority from the U.S. Treasury. BPA estimates that infrastructure projects necessary to improve transmission capability and hydropower efficiency will require approximately $2 billion in additional borrowing authority.

BPA is a integral and essential part of both the generation and the transmission infrastructure in the Northwest. It owns and operates about 75 percent of the high voltage transmission in our region. Those transmission facilities are currently operating at or near capacity levels. Additional transmission capacity is needed to allow for the integration of new electricity generation facilities that are being proposed to meet growing demand in Washington and throughout the Northwest. BPA needs to make increased capital investments soon not only to integrate this new generation, but also to preserve the reliability of the existing transmission system.

The Federal Columbia River Power System (FCRPS) contributes about 40 percent of the region's firm electricity generation. Many of these hydroelectric facilities are 40 years or more old and need updates and improvements to maximize their efficiency. BPA informs us that with increased investment in these facilities it will be possible to increase generation capability by as much as 300 aMW. These investments are cost-effective -- they will return more than the cost of capital -- and would contribute importantly to the region's need for new generating capability.

In March of this year, the Federal Energy Regulatory Commission (FERC) identified infrastructure enhancements in transmission and hydropower efficiency as critical to meeting the growing power needs of the West.[1] We believe that BPA's request for additional borrowing authority will permit it to undertake projects that address the problem FERC has identified. Given the recent unprecedented upward pressure on BPA rates caused by runaway prices in the wholesale power market, we are concerned that needed infrastructure investments may not happen in a timely manner without this additional borrowing authority.

We urge your support of the additional borrowing authority requested by BPA. Thank you very much for you help and attention.

Sincerely,

Marilyn Showalter, Chairwoman
Washington Utilities and Transportation Commission

Richard Hemstad, Commissioner
Washington Utilities and Transportation Commission

Patrick Oshie, Commissioner
Washington Utilities and Transportation Commission

cc: Stephen J. Wright, Acting Administrator, BPA
The Honorable Senator Patty Murray
The Honorable Senator Maria Cantwell
The Honorable Representative Jay Inslee
The Honorable Representative Rick Larsen
The Honorable Representative Brian Baird
The Honorable Representative Doc Hastings
The Honorable Representative George R. Nethercutt, Jr.
The Honorable Representative Norman D. Dicks
The Honorable Representative Jim McDermott
The Honorable Representative Jennifer Dunn
The Honorable Representative Adam Smith

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[1] *Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States and Requesting Comments on Further Actions to Increase Energy Supply and Decrease Energy Consumption.* Docket #EL01-47-000. Federal Energy Regulatory Commission. March 14, 2001.

JOHN A. KITZHABER, M.D.
GOVERNOR

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG #: 01-0380
RECEIPT DATE:
7·17·01
DUE DATE:
INFO ONLY

July 16, 2001

The Honorable Robert C. Byrd
Chairman Interior Subcommittee
Senate Committee on Appropriations
SH 123 Hart Senate Office Building
Washington, D.C. 20510-6033

INFO ONLY: KR-7C
cc: A-7, D-7, KN/Wash, KR-7, L-7, P-6, PG-5, KE-4, DF-2, T/Ditt2, Cindy Custer-KR/WSGL
Anne Morrow KR-7C

Dear Mr. Chairman:

I am writing in support of the Bonneville Power Administration's request for an additional $2 billion in borrowing authority from the U.S. Treasury. The additional authority is needed for critical investments in the Northwest's high-voltage transmission system and hydroelectric facilities.

Bonneville owns and operates about 75 percent of the Northwest's high-voltage transmission. Its system is now at or near capacity. As a result, the system cannot carry all the electricity generated from new power plants coming on line. Bonneville must make substantial investments in new transmission capacity to ensure the continued reliability of the Northwest power system.

Also, Bonneville supplies about 40 percent of the electricity used in the Northwest. Most of that supply comes from hydroelectric facilities – many of which are old and need improvements to achieve full efficiency. With added borrowing authority, Bonneville can upgrade these facilities and increase supply by an amount equivalent to the output of a new power plant. In a power-short region, these are needed, timely investments.

urge you to support Bonneville's request.

Thank you for your consideration of this matter.

Sincerely,

John A. Kitzhaber, M.D.

Oregon Delegation
Steve Wright, Acting Administrator, Bonneville Power Administration

City of Seattle
Paul Schell, Mayor
Seattle City Light
Gary Zarker, Superintendent

RECEIVED BY BPA ADMINISTRATOR'S OFC LOG #: 01-0383
RECEIPT DATE: 7.18.01
DUE DATE:
INFO ONLY

July 17, 2001

INFO ONLY: A-7, D-7, KN/Wash, L-7, P-6, PG-5, KE-4, DF-2, T/Ditt2, Cindy Custer-KR/WSGL

Robert C. Byrd
Chairman, Senate Committee on Appropriations
311 Hart Senate Office Building
Washington, DC 20510

Chairman Byrd:

As you know, the Bonneville Power Administration (BPA) has sought a $2 billion increase in borrowing authority to primarily finance transmission expansion projects in the Pacific Northwest. The current language in the Energy and Water Appropriations bill authorized $2 billion, but makes spending subject to annual appropriation. I urge you to support in conference language approved the Energy and Water subcommittee that does not condition bonding authority on the annual appropriations process.

I believe that the Northwest, like many parts of the country, has under-invested in transmission. Much of that is attributable to uncertainty over industry structure and cost recovery. Much is also attributable to a surplus of generation and transmission capacity along the West Coast. The problems of the last year have made us acutely aware of the need for substantial investment in generation and transmission by public utilities, private utilities, independent power producers, and Bonneville.

The principal difficulty with an annual appropriations process is that it prevents investments in capital intensive, long-lead time transmission projects. Substantial investments are needed immediately to address congested paths in Puget Sound. We have been subject to a number of transmission curtailments this year that prevent our access to power from Boundary dam. Investor owned utilities in the northwest have faced the same problem – the "west of Hatwai" problem – bringing in power from generation they own in Montana and Wyoming. Northwest congestion greatly impairs our ability to assist California in summer, and vice versa in winter. In addition to relief of congested paths, Bonneville must add transmission capacity to support new generating projects being built in the region. We believe that we cannot wait for the formation of a FERC-jurisdictional Regional transmission Organization to decide on a perfect expansion plan.

I do share the concern of Northwest investor owned utilities that BPA investments address top priority problems in a cost-effective manner. They should focus on interconnecting generation and resolving congestion in projects that are not likely candidate investments for other parties. A technical review committee can provide guidance on these issues to the Administrator.

I'd like to reiterate my support for an energy and water appropriations bill that includes $2 billion in increased BPA borrowing authority, not subject to authorizations on an annual basis. I would be delighted to answer any questions you have on this issue.

Sincerely,

for Gary Zarker
Superintendent

JH:smb

cc: Senator Patty Murray
Senator Maria Cantwell
Representative Jay Inslee
Representative Rick Larsen
Representative Brian Baird
Representative Doc Hastings
Representative George Nethercutt
Representative Norman Dicks
Representative Jim McDermott
Representative Jennifer Dunn
Representative Adam Smith

700 Fifth Avenue, Suite 3300, Seattle, WA 98104-5031
Tel: (206) 625-3000, TTY/TDD: (206) 684-3225, Fax: (206) 625-3709

Robert P. Gannon
Chairman of the Board,
CEO and President

The Montana Power Company

July 12, 2001

Chairman Robert C. Byrd
Senate Committee on Appropriations
311 Senate Hart Office Building
Washington, DC 20510

Dear Chairman Byrd:

I am writing to express Montana Power Company's support for increasing the borrowing authority of the Bonneville Power Administration (BPA) to facilitate the construction of additional electric transmission facilities. This funding is critically important to improve the capacity and reliability of BPA's transmission system for the benefit of consumers throughout the Pacific Northwest.

I am pleased that BPA has recently agreed to form a review committee with its transmission customers to assure that transmission improvements are prioritized so as to provide the most cost-effective and reliable service for the region. Montana Power will gladly participate in the important work to be undertaken by this review committee. It would be appropriate for language supporting the formation of this committee to be included in your Committee report.

Montana Power has been, and continues to be, concerned about BPA's program to install fiber optic cable far in excess of BPA's legitimate operational requirements. I encourage the Committee to carefully review any additional funding that BPA may request for this purpose.

If you or your staff have any questions about Montana Power's support for additional BPA borrowing authority, please contact Bill Pascoe, Montana Power's Vice President, Energy Supply at (406) 497-4212.

Sincerely,

Robert P. Gannon

40 East Broadway Street • Butte, Montana 59701-9394
Telephone: 406-497-2403 • Facsimile: 406-497-2150 • e-mail: rgannon@mtpower.com

CC: Senator Conrad Burns
Senator Max Baucus
Representative Dennis Rehberg
Governor Judy Martz
Senator Ted Stevens
Senator Pete Domenici
Senator Patty Murray
Senator Larry Craig
Representative Sonny Callahan
Representative Peter Visclosky
Secretary Spencer Abraham
Stephen Wright – Acting Administrator, BPA

Appendix J – Letters of Support

August 30, 2001

Addressees

Subject: Infrastructure Technical Review Committee Report

Portions of the Northwest transmission system are approaching gridlock. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk.

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

To ensure that BPA's proposal designs and prioritizes improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers, a technical and economic review committee was formed. The committee drew on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC), Operating Committee (OC) and the Northwest Regional Transmission Association ("NRTA") Planning Committee ("PC"). The committee was asked to report its recommendations by August 30, 2001 to enable BPA to install necessary system facilities as soon as possible. A critical first step is securing additional borrowing authority for BPA.

Attached is a report on the transmission infrastructure proposal that contains the conclusions and recommendations of the review committee. This is the first annual report on BPA's major transmission investments.

Ken Morris
PacifiCorp

John Martinsen
Snohomish PUD

Wayman Robinett
Puget Sound Energy

Hardev Juj
Seattle City Light

Scott Waples
AvistaCorp

Ronald Schellberg
Idaho Power Company

John Leland
Montana Power Company

Jim Eden
PGE Company

cc
Infrastructure Technical Review Committee

Northwest Electric Power Interests

August 8, 2001

Vice President Richard B. Cheney
The White House
Washington, DC 20501

Dear Mr. Vice President:

We are writing to express our strong support for increasing the amount of funding that the Bonneville Power Administration (BPA) may borrow from the U.S. Treasury.

As investor-owned utilities, consumer-owned utilities, industrial customers, and independent power producers, all doing business in the Pacific Northwest, we often disagree on matters relating to the Northwest power system. But we are absolutely united on at least one point: that substantially increasing the reliability and capacity of the BPA transmission system is essential to the economic health of both the Northwest and the entire West.

The BPA transmission system is already heavily constrained as it attempts to serve existing loads and generation facilities, and the problem is only going to get worse unless dramatic steps are taken. As the report of your Energy Task Force made clear, new generation facilities are essential to solving the electricity crisis. Right now, the call for new generation is being answered -- developers have announced plans to build many new plants in the Northwest. This new generation will benefit consumers in all 11 Western states served by the regional transmission system known as the western interconnection.

But those new generation facilities cannot help solve the supply problem unless they are interconnected to a reliable regional transmission system. Because BPA owns and operates over 75 percent of the high-voltage transmission system in the Northwest, and no major investments have been made in that system for over a decade, the transmission system that would bring these new supplies to consumers is simply not prepared to do the job. Unless relieved through substantial infrastructure improvements, the constraints that plague the BPA transmission system will prolong the current electricity crisis and contribute to future crises.

We understand that solving this problem will not be free. All BPA transmission customers will bear the total costs of BPA's transmission investments through transmission rates. In turn, the revenues from transmission rates will be used by BPA to repay all the money borrowed from the Treasury, with interest. But we cannot move forward toward a solution until the federal government does its part by increasing BPA's borrowing authority.

One recent development gives us, and hopefully you, extra confidence that this new borrowing authority will be well spent. To assure that BPA properly prioritizes its transmission investments, a technical review committee consisting of BPA's transmission customers was recently created, and is already beginning its work. This review process (which received the full support of the Senate Appropriations Committee in its July 13 report on the Energy and Water Development Appropriations bill) will allow meaningful customer input and thereby help assure that BPA's transmission investments will provide the most cost-effective, reliable service for the region's consumers.

In conclusion, we ask that you put the Administration on record as supporting an increase in BPA's borrowing authority for FY 2002, so that BPA can immediately move ahead on critical, multi-year investments in the transmission system. We also ask that you promptly transmit a statement of your views to the Senate and House Appropriations Committees. With the Administration's support, we are hopeful that this matter will be successfully concluded when those Committees meet in conference on the Energy and Water Appropriations bill after the August recess.

Kris Mikkelsen

Kris Mikkelsen
General Manager
Inland Power & Light

Al Gonzalez
General Manager
Central Electric
Cooperative, Inc.

Patrick Ashby
General Manager
Tillamook Public Utility
District

James W Sanders
General Manger
Benton Public Utility
District

Don Godard
Manager
Grant Public Utility District

David E. Piper

David E. Piper
Chief Executive Officer
Pacific Northwest
Generating Company

Pamela G. Lesh
Vice President
Public Policy & Regulatory
Affairs
Portland General Electric
Company

James C. Miller
Senior Vice President
Delivery
Idaho Power Company

Brett Wilcox
President
Goldendale Aluminum and
Northwest Aluminum

Jack Haffey
President and Chief Operating Officer
The Montana Power Company

Gary Zarker
Superintendent
Seattle City Light

Gary Ely
Chairman, Pres. & CEO
Avista Corp.

Alan Richardson
Chairman of the Board
PacifiCorp

Jerry Leone
Manager
Public Power Council

Charles E. Martin
President
National Energy Systems Company
Sumas Energy, Inc.

Steve Johnson
Executive Director
Washington PUD Association

Paul T. Champagne
President
PPL Global

M. Steven Eldridge
General Manager & CEO
Umatilla Electric Cooperative

Mark Gendron
Manager
Idaho Falls Power

Randy L. Berggren
General Manager
Eugene Water & Electric Board

cc: Secretary of Energy Spencer Abraham
Senate Appropriations Committee Chairman Robert C. Byrd
House Appropriations Committee Chairman C.W. Young
Senate Budget Committee Chairman Kent Conrad
House Budget Committee Chairman Jim Nussle
Senate Energy Committee Chairman Jeff Bingaman
House Energy and Commerce Chairman W.J. "Billy" Tauzin
OMB Director Mitchell E. Daniels Jr.
NW members of Congress
Governor Dirk Kempthorne
Governor John Kitzhaber
Governor Gary Locke
Governor Judy Martz

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG # [redacted]
RECEIPT DATE:
6·28·01
DUE DATE:
INFO ONLY

PG&E Corporation

Steven L. Kline
Vice President
Federal Governmental &
Regulatory Relations

700 11th Street NW, Suite 250
Washington, DC 20001
202.638.3500
Fax: 202.638.3522
Internet: steven.kline@pge-corp.com

June 25, 2001

The Honorable Spencer Abraham
Secretary of Energy
1000 Independence Ave.
Washington, DC 20585-0001

INFO ONLY: Kip Moxness-TM/Ditt2
cc: A-7, D-7, KN/Wash, L-7, P-6, T/Ditt2, DF-2, Scott Wilson-PT-5

Dear Secretary Abraham:

I am writing today to express PG&E Corporation's support for efforts by the Bonneville Power Administration (BPA) to improve its ability to deliver power in the West. Specifically, we would like to endorse BPA's request for additional federal borrowing authority to finance transmission construction.

As you know, significant progress has been made toward returning to supply/demand balance in the West. PG&E Corporation's National Energy Group is contributing to this effort. Currently, we have more than 4,000 megawatts in construction or development in the region, and we continue to look at potential sites. We also are upgrading our natural gas pipeline infrastructure to help ensure the new plants are fueled.

As new generating projects begin to come on line, the situation in the West undoubtedly will improve from both a supply and price stability perspective. But to get that power to market, we must improve the region's aging transmission systems. And we must begin that effort now so that the transmission capacity is ready when the generating capacity becomes available.

BPA operates one of the most important transmission systems in the West. Because of the broad interconnectedness of the Western System Coordinating Council grid, the ability of BPA to deliver power from Northwest facilities impacts reliability throughout the region. That said, we are very concerned that BPA's transmission system is not prepared to accommodate the new generating facilities now in development or construction in the Northwest.

We understand BPA is seeking to extend its federal borrowing authority so that it has financial means to make critically needed transmission upgrades. We support this effort as an important component of the overall effort to solve the West's energy problems. We also strongly urge BPA to begin immediately planning for transmission upgrades in the most critical corridors. Priority should be given to transmission serving areas where advance plant construction and development are underway. We are concerned that projects ready for construction cannot get a commitment from BPA to provide transmission service coincident with the completion of construction.

As always, Mr. Secretary, we greatly appreciate your attention to the issues in the West and your commitment to working with the region to address the many challenges facing us.

Please don't hesitate to call me at any time if I can be of assistance to you.

Sincerely,

cc: Mr. Steven Wright ✓

Folder Profile

Control #	2001-016257
Name	Letter to Secretary Spencer Abraham from the Honorable G
Priority	Essential Critical
Folder Trigger	Letter
DOE Addressee	Spencer Abraham
Source	SO
Date Received	7/9/01
Subject Text	Governor Gary Locke, State of Washington, urges the Secretary to support the BPA's request to increase its borrowing authority from the U.S. Treasury and within the Administration and before Congress
Correspondence Date	7/6/01
RIDS Information	Head of Agency
Sensitivity	Not Applicable
Action Office #	
Classification	None
Signature/Approval	Spencer Abraham
Point of Contact	CARPENTC
Organization ID	EXECCORR2
Action Requested	Prepare Response
Assigned To	BPA
Special Instructions	CI concurrence required.
Date Due	7/18/01
Date Completed	

PRIORITY

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ADMINISTRATOR'S
OFC-LOG #: 01-0344

RECEIPT DATE:
7-10-01

DUE DATE:
7-20-01

Assign: KR-7-C
cc: A, D, KN, KR, DF, P, T

2001-016257 7/9 A 10:53

GARY LOCKE
Governor

STATE OF WASHINGTON
OFFICE OF THE GOVERNOR
P.O. Box 40002 • Olympia, Washington 98504-0002 • (360) 753-6780 • TTY/TDD (360) 753-6466

July 6, 2001

The Honorable Spencer Abraham
Secretary of Energy
United States Department of Energy
James Forrestal Building
1000 Independence Avenue S.W.
Washington, D.C. 20585

Dear Secretary Abraham:

I am writing to express my strong support for the Bonneville Power Administration's (BPA's) request to increase its borrowing authority from the U.S. Treasury.

BPA estimates that it will need approximately $2 billion in additional authority to help finance new capital investment for transmission, generation and conservation. Because BPA is such an integral part of both the generation and the transmission system in the Pacific Northwest, it is critical that BPA have sufficient borrowing authority to ensure that these infrastructure improvements are made in a timely manner.

BPA's transmission system accounts for about 75 percent of the high voltage transmission in the Pacific Northwest. It is now at or near capacity. Additional transmission capacity is needed to allow for the integration of the new generation being proposed for the Northwest. BPA needs to make increased capital investments soon to handle this new generation and preserve the reliability of the current transmission system.

In addition, the Federal Columbia River Power System contributes about 40 percent of the region's firm energy. Many of these hydroelectric facilities are more than 40 years old and need updates and improvements to maximize their efficiency. With increased investment in these facilities it will be possible to increase generation capability by as much as 300 average megawatts. The investments in system efficiencies surely will return more than the cost of capital.

For these reasons, I urge you to support BPA's request within the Administration and before Congress. Thank you for your attention to this matter.

Sincerely,

Gary Locke
Governor

PSE PUGET SOUND ENERGY

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG #: 01-0366
RECEIPT DATE:
7-12-01
DUE DATE: INFO ONLY

A, D, KN, DF, L P T

July 12, 2001

Chairman Robert C. Byrd
Senate Committee on Appropriations
311 Senate Hart Office Building
Washington, DC 20510

Dear Chairman Byrd:

I am writing to express Puget Sound Energy, Inc.'s support for increasing the borrowing authority of the Bonneville Power Administration (BPA) to facilitate the construction of additional electric transmission facilities. This funding is critically important to improve the capacity and reliability of BPA's transmission system for the benefit of consumers throughout the Pacific Northwest.

I am pleased that BPA has recently agreed to form a review committee so that its transmission customers can be assured that transmission improvements are economically justified and prioritized so as to provide the most cost-effective and reliable service for the region. Puget Sound Energy will gladly participate in the important work to be undertaken by this review committee. It would be appropriate for language supporting the formation of this committee to be included in your Committee report.

If you or your staff have any questions about Puget Sound Energy's support for additional BPA borrowing authority, please contact Bill Gaines, Puget Sound Energy's Vice President, Energy Supply at (425) 462-3145.

Sincerely,

William S. Weaver
President and Chief Executive Officer

cc: Secretary Spencer Abraham
Senator Patty Murray
Stephen Wright – Acting Administrator, BPA

ALAN RICHARDSON
Chairman

825 N.E. Multnomah, Suite 2000
Portland, Oregon 97232-4116
(503) 813-6765
FAX (503) 813-7109

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MINISTRATOR'S
C-LOG #: 01-03367
CEIPT DATE:
7-12-01
UE DATE: INFO ONLY

A, D, KN, DF, L, P, T

PACIFICORP

July 11, 2001

The Honorable Robert C. Byrd
Chairman, Committee on Appropriations
United States Senate
Washington, D.C. 20510

Dear Senator Byrd:

PacifiCorp supports an increase in borrowing authority for the Bonneville Power Administration (BPA) as part of H.R. 2311, the Fiscal Year 2002 Energy and Water Appropriations that may be considered by your Committee July 12, 2001.

PacifiCorp is an investor-owned utility serving 1.5 million retail electric consumers in six western states.

By permitting Bonneville to make additional investments in its transmission network, this increase in borrowing authority would represent a critical step toward needed improvements in the capacity and reliability of BPA's transmission system. Such investments need to be made for the benefit of all electric consumers throughout the Pacific Northwest and, indirectly, the entire west.

Bonneville has agreed to form a technical review committee with its transmission customers to help assure that transmission improvements are prioritized to provide the most cost-effective and reliable service for the region. We respectfully request the Report accompanying the Committee's action on H.R. 2311 reflect positively on the formation of this committee.

Thank you for your consideration of our request.

Sincerely,

Alan V. Richardson
Chairman of the Board

Cc: The Honorable Ted Stevens
The Honorable Harry Reid
The Honorable Pet V. Domenici
The Honorable Patty Murray
The Honorable Larry E. Craig
Steve Wright, BPA

Avista Corp. Idaho Power Company Montana Power Company PacifiCorp Portland General Electric Puget Sound Energy

Northwest Investor Owned Utilities

July 11, 2001

Chairman Robert C. Byrd
Senate Committee on Appropriations
311 Senate Hart Office Building
Washington, DC 20510

Dear Chairman Byrd:

On behalf of Avista Corporation, Idaho Power Company, Montana Power Company, PacifiCorp, Portland General Electric, and Puget Sound Energy, Inc., I am writing to voice our strong support for increasing the borrowing authority of the Bonneville Power Administration (BPA) as part of the Energy and Water Appropriations bill that will be considered by your Committee tomorrow. We believe that this is a critical step toward improving the capacity and reliability of BPA's transmission system, for the benefit of consumers throughout the Pacific Northwest. We are pleased to inform you that BPA has recently agreed to form a technical review committee with its transmission customers to assure that transmission improvements are prioritized so as to provide the most cost-effective and reliable service for the region. We respectfully request that language in support of the formation of this committee be included in your Committee report.

If you or your staff have any questions, please feel free to call me.

Sincerely,

James Litchfield
Consultant for the
Investor Owned Utilities
503-222-9480
lcg@europa.com

EIVED BY BPA
INISTRATOR'S
-LOG #:01-0368
RECEIPT DATE:
7-12-01
E DATE:
INFO ONLY
A, D, KN, DF, L, P, T

cc: Senator Ted Stevens
Senator Jack Reed
Senator Pete Domenici
Senator Patty Murray
Senator Conrad Burns
Rep. Sonny Callahan
Rep. Peter Visclosky
Secretary Spencer Abraham
Stephen Wright – Acting Administrator, Bonneville Power Administration

PGE
Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-8401 • Fax (503) 778-5566

Peggy Y. Fowler
CEO and President

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG #: 01-0371
RECEIPT DATE:
7-13-01
DUE DATE:
INFO ONLY
Info Only: A, D, KN, DF, L, P, T

July 12, 2001

Chairman Robert C. Byrd
Senate Committee on Appropriations
311 Senate Hart Office Building
Washington, DC 20510

Dear Chairman Byrd:

I am writing to express Portland General Electric Company's support for increasing the transmission borrowing authority of the Bonneville Power Administration (BPA) as part of the Energy and Water Appropriations bill. We believe that this is a critical step toward improving the capacity and reliability of the transmission system for the benefit of consumers throughout the Pacific Northwest. We are also pleased BPA has agreed to form a technical review committee with its transmission customers to assure that transmission improvements are prioritized to provide the most cost-effective and reliable service for the region.

We look forward to working cooperatively with BPA to review proposed capital projects and helping assure dependable transmission in the region. We respectfully request that language in support of the formation of this committee be included in your Committee report.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Peggy Fowler

cc: ✓Steve Wright, BPA - Acting Administrator and CEO
Jeff Stier, BPA - Vice President
Secretary of Energy Spencer Abraham
Senator Patty Murray
Senator Gordon Smith
Senator Ron Wyden
Michael A. Andrews, Vinson and Elkins

PUBLIC SERVICE COMMISSION

1701 Prospect Avenue • PO Box 202601
Helena, Montana 59620-2601
Telephone: (406) 444-6166
FAX #: (406) 444-7618
E-MAIL: gfeland@state.mt.us

Gary Feland, Commissioner
District 1

July 12, 2001

Post-it® Fax Note 7671	Date 7/16/01 # of pages ▸ 1
To Karen Hunt	From Gail Kuntz
Co./Dept. Steve Wright	Co. BPA-MSGX
Phone #	Phone # 406 449 5790
Fax # 503-230-4018	Fax #

Secretary Spencer Abraham
Room 7B22
1000 Independence Avenue
Washington, D.C. 20585

Dear Secretary Abraham:

On behalf of the Montana Public Service Commission, I am writing to express support for the Bonneville Power Administration's (BPA) request for an increase in its borrowing authority from the U.S. Treasury. BPA estimates its need for the development of a package of infrastructure improvements at approximately two (2) billion dollars in additional borrowing authority.

Inadequate electrical generation and transmission infrastructure has been one of the fundamental causes of the electricity price crisis we are experiencing in the west. If new generation and transmission are to be built anytime soon, BPA will necessarily play a vital role.

BPA must make significant capital investments in its high voltage transmission system in the Pacific Northwest to serve its load. New generation is being built, and significantly more is scheduled for construction. However, unless BPA can integrate this new production into its system it may not be built.

BPA must also support newly developing efficiency technologies as they become financially viable to encourage consumers to make critical conservation and demand side management investments. Investment in conservation helps supplant costly power purchases, and because it involves private interests, creates additional jobs in the private sector.

Some of the transmission infrastructure enhancement proposed by BPA will affect the wholesale electricity market in Montana. Therefore, the Commission's support for an increase in BPA's borrowing authority is conditioned on the opportunity of Montana to participate in the decision making process for the various projects that BPA proposes.

Thank you for your consideration.

Sincerely,

Gary Feland
Chairman

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ADMINISTRATOR'S
OFC-LOG #: 01-0381
RECEIPT DATE: 7-17-01
DUE DATE: INFO ONLY

INFO ONLY: Gail Kuntz-KR/MSGL
cc: A-7, D-7, KN/Wash, KR-7, L-7, P-6, PG-5, KE-4, DF-2, T/Ditt2

PG&E Corporation

RECEIVED BY BPA ADMINISTRATOR'S OFC-LOG #: 01.0373
RECEIPT DATE: 7 16 01
DUE DATE: INFO ONLY

Steven L. Kline
Vice President
Federal Governmental & Regulatory Relations

700 11th Street NW, Suite 250
Washington, DC 20001
202.638.3500
Fax: 202.638.3522
Internet: steven.kline@pge-corp.com

July 11, 2001

Honorable Mitchell E. Daniels, Jr.
Director
Office of Management & Budget
Eisenhower Executive Office Building
17th & Pennsylvania Avenue, NW
Washington DC, 20503

INFO ONLY: A-7, D-7, KN/Wash, L-7, P-6, T/Ditt2, DF-2

Dear Director Daniels:

I am writing to express PG&E Corporation's support for efforts to improve the Bonneville Power Administration's (BPA) ability to deliver electricity in the West. Specifically, we endorse the request for additional federal borrowing authority to allow BPA to finance transmission construction.

Significant progress has been made toward returning to a balance in electricity supply and demand in the West. PG&E Corporation's National Energy Group is contributing to this effort. Currently, we have more than 4,000 megawatts of electric generation in construction or development in the region, and we continue to look at potential plant sites. We also are upgrading our natural gas pipeline infrastructure to help ensure the new plants are fueled.

As new generating projects begin to come on line, the situation in the West undoubtedly will improve from both a supply and price stability perspective. But to get that power to market, we must improve the region's aging transmission systems. We must begin that effort now so that the transmission capacity is ready when the generating capacity becomes available.

As you know, BPA operates one of the most important transmission systems in the West. Because of the broad interconnectedness of the Western System Coordinating Council grid, the ability of BPA to deliver power from Northwest facilities impacts reliability throughout the region. That said, we are very concerned that BPA's transmission system is not prepared to accommodate the new generating facilities now in development or construction in the Northwest.

We understand BPA needs to extend its federal borrowing authority so that it has the financial means to make critically needed transmission upgrades. We support this effort as an important component of the overall effort to solve the West's energy problems. We also strongly urge Bonneville to begin immediately to plan for transmission upgrades in the most critical corridors. Priority should be given to transmission serving areas where advance plant construction and development are underway in order that plants ready for construction can be assured that BPA will provide transmission service coincident with their completion.

Please don't hesitate to call me at any time if I can be of assistance to you.

Sincerely,

cc: ~~Mr. Stephen Wright~~ ✓
Honorable Harry Reid
Honorable Pete Domenici
Honorable Larry Craig
Honorable Conrad Burns
Honorable Diane Feinstein

Avista Corp.
1411 East Mission MSC-12 PO Box 3727
Spokane, Washington 99220-3727
Telephone 509-489-0500

Gary G. Ely
Chairman of the Board,
President and Chief Executive Officer

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG #: 01-0375
RECEIPT DATE:
7.16.01
DUE DATE:
INFO ONLY

AVISTA Corp.

July 11, 2001

INFO ONLY: A-7, D-7, KN/Wash, L-7, P-6, T/Ditt2, DF-2

Chairman Robert C. Byrd
Senate Committee on Appropriations
311 Senate Hart Office Building
Washington, DC 20510

Dear Chairman Byrd:

On behalf of Avista Corporation, I am writing to follow-up on the July 11 letter you received from Jim Litchfield regarding the strong support of the Northwest investor-owned utilities for increasing the borrowing authority of the Bonneville Power Administration (BPA) as part of the Energy and Water Appropriations bill.

Avista supports increasing BPA's borrowing authority because of the critical need to improve the BPA transmission system. The BPA transmission system is the "backbone" of the region's transmission grid, but it has not been significantly expanded for at least 10 years. Consequently, BPA does not have sufficient transmission capacity to accommodate power from all of the current and pending generation facilities that are needed to satisfy the energy needs of the Northwest. Unless a substantial investment is made in upgrading the BPA transmission system in the very near future, we run a substantial risk of serious reliability problems in the region.

I am particularly pleased that BPA has agreed to form a technical and economical review committee with its transmission customers. We look forward to working with BPA to assure that its transmission improvements are prioritized so as to provide the most cost-effective and reliable service for the region.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Gary Ely

cc: Senator Ted Stevens
Senator Jack Reed
Senator Pete Domenici
Senator Patty Murray
Senator Conrad Burns
Rep. Sonny Callahan
Rep. Peter Visclosky
Secretary Spencer Abraham
Stephen Wright – Acting Administrator, Bonneville Power Administration

RECEIVED BY BPA ADMINISTRATOR'S OFC LOG #: [redacted]
RECEIPT DATE: 7 16 01
DUE DATE:
INFO ONLY

United States Senate
WASHINGTON, DC 20510

July 12, 2001

The Honorable Mitch Daniels
Director
Office of Management and Budget
Old Executive Office Building
Washington, D.C. 20503

INFO ONLY: KR-7C
cc: A-7, D-7, KN/Wash, L-7, P-6, KE-4, T/Ditt2, DF-2

Dear Director Daniels:

We are writing with regard to two issues of vital importance to our region: the Bonneville Power Administration's access to credits under section 4(h)(10)(C) of the Northwest Power Act and BPA's need for an increase in its authority to sell bonds to the U.S. Treasury.

Under the Northwest Power Act, BPA is required to make expenditures to protect, mitigate, and enhance fish and wildlife affected by Federal hydro projects. BPA is required to do so consistent with the fish and wildlife program of the Northwest Power Planning Council (Council). The Act also requires BPA to take as a credit against its debt repayments to Treasury the non-power project purposes' share of BPA's fish and wildlife costs. In effect, section 4(h)(10)(C) of the Act directs BPA – acting on behalf of its ratepayers – to appropriately allocate to the U.S. Treasury its share of the mitigation costs for these Federal projects.

Due to the persistent drought in the Northwest and the extraordinarily high wholesale power market prices in the West, fish and wildlife mitigation costs in the Columbia River basin have increased dramatically this year. Therefore, the 4(h)(10)(C) credits also have increased significantly. BPA's access to the credits is currently implemented by reducing annual cash transfers to Treasury. The credits do not reduce BPA's payment obligation; rather the credits are treated as a source of funds that satisfies the payment obligation. It is essential that the Administration support Bonneville's access to credits for this year's salmon recovery costs, as well as credits that are supposed to be made available under adverse water conditions through the Fish Cost Contingency Fund established in 1996.

The second issue of importance, BPA's need for an increase in its authority to sell bonds to the U.S. Treasury, is driven by system improvements BPA must make to maintain the reliability of the Northwest's electricity supply and relieve crippling transmission system congestion. In addition, Bonneville is being called upon to integrate a substantial amount of new generation now being planned by private developers in the region. Finally, BPA has identified investments it can make using its self-financing authority to increase generation from existing facilities within the Federal Columbia River Power System, and to step up regional energy conservation efforts. To assure that BPA continues to have sufficient financial resources necessary to make needed electric infrastructure investments in a timely manner, BPA will need up to $2 billion in additional borrowing authority above the current $3.75 billion limit.

We want to impress upon you the importance of these two issues. The Northwest's economy and our natural environment depend on BPA's ability to secure its access to the credits and the additional borrowing authority.

Sincerely,

Gordon H. Smith
United States Senate

Maria Cantwell
United States Senate

Ron Wyden
United States Senate

Larry Craig
United States Senate

Patty Murray
United States Senate

Max Baucus
United States Senate

Mike Crapo
United States Senate

Conrad Burns
United States Senate

NORTHWEST POWER PLANNING COUNCIL

851 S.W. SIXTH AVENUE, SUITE 1100
PORTLAND, OREGON 97204-1348

Fax: 503-820-2370
Phone: 503-222-5161
1-800-452-5161
Internet: www.nwcouncil.org

July 6, 2001

The Honorable Spencer Abraham
Secretary of Energy
U.S. Department of Energy
Forrestal Building 1000 Independence Avenue, S.W.
Washington, D.C. 20585

INFO ONLY: KR-7
cc: A-7, D-7, KN/Wash, KR-7C, L-7, P-6, PG-5, KE-4, DF-2, T/Ditt2

Dear Secretary Abraham:

The Northwest Power Planning Council supports the Bonneville Power Administration's request for additional Federal Treasury borrowing authority for capital improvements to the Federal Columbia River Power System (FCRPS). Needed upgrades and improvements to the high-voltage transmission system, hydroelectric facilities and energy conservation program will require Bonneville to have access to additional capital funds in the near-term.

In particular, this year's West Coast electricity crisis has helped underscore serious constraints and deficiencies within the transmission system. The system is currently operating at or near full capacity, and is under increasing stress. The robust activity in the wholesale power market is pressuring Bonneville to run the system harder and for patterns of transactions for which it was not designed. This is making it more difficult to schedule maintenance and construction activities. In addition, there is serious concern that the transmission system will not have the capacity necessary to handle the new generation in the Northwest that is needed to bring supply and demand back into balance. Bonneville's access to additional borrowing authority is necessary to ensure long-term system reliability for the Northwest and the entire West Coast.

The Council also supports additional borrowing authority for improvements, additions and replacements at hydroelectric facilities within the FCRPS and the fishery mitigation projects associated with them. In 1992, Congress gave Bonneville the authority to enter into direct funding agreements with the Corps of Engineers and the Bureau of Reclamation for upgrades at their hydroelectric projects. Bonneville has a similar direct funding agreement with the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan hatcheries. These agreements preclude the need for congressional appropriations for these activities, but increase Bonneville's capital borrowing requirements. The Council recognizes this need and supports new borrowing authority to increase the efficiency and reliability of the FCRPS and minimize system impacts on fish and wildlife.

The electricity crisis has also highlighted the importance of vigorous and sustained energy conservation efforts in the Northwest. Unfortunately, during the 1990s, Bonneville's level of investment in conservation decreased substantially due to the emerging competitive electricity market and financial uncertainties. The consequences of this change in policy have been exposed by the astonishingly high electricity prices that we've experienced this past year. Accordingly, it is important that Bonneville regain its leadership in assisting regional utilities and other customers to invest in cost-effective conservation measures while recognizing the market realities of the evolving wholesale power supply market. Additional borrowing authority will allow Bonneville to stimulate such investments throughout the Northwest.

The Council believes that increases in borrowing authority should be accompanied by a high level of accountability in the utilization of the funds. Because the electric ratepayers of the region repay these investments, and because the transmission system supports transactions by several non-federal entities, there is a need to ensure adequate regional participation and oversight in the projects pursued. An open, independent process should be established that identifies least-cost solutions and prioritizes investments that result in a completion schedule of projects. The results of such a process should be included in Bonneville's annual budget submittal for an additional level of accountability. The Council is available to participate in such a process in any way deemed appropriate by the regional entities.

Thank you for your attention to his matter, and please do not hesitate to contact me if you have any questions or comments.

Sincerely,

Frank L. Cassidy, Jr.
Chair

Identical letter sent to: The Honorable Spencer Abraham, Secretary of Energy
Members of the Northwest congressional delegation
House and Senate Committees on Appropriations

NORTHWEST POWER PLANNING COUNCIL

851 S.W. SIXTH AVENUE, SUITE 1100
PORTLAND, OREGON 97204-1348

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ADMINISTRATOR'S
OFC-LOG # [redacted]
RECEIPT DATE:
7·16·01
DUE DATE:
INFO ONLY

July 6, 2001

The Honorable Patty Murray
United States Senate
173 Russell Senate Office Building
Washington, D.C. 20510-4704

INFO ONLY: KR-7
cc: A-7, D-7, KN/Wash, KR-7C, L-7, P-6, PG-5, KE-4, DF-2, T/Ditt2

Dear Senator Murray:

The Northwest Power Planning Council supports the Bonneville Power Administration's request for additional Federal Treasury borrowing authority for capital improvements to the Federal Columbia River Power System (FCRPS). Needed upgrades and improvements to the high-voltage transmission system, hydroelectric facilities and energy conservation program will require Bonneville to have access to additional capital funds in the near-term.

In particular, this year's West Coast electricity crisis has helped underscore serious constraints and deficiencies within the transmission system. The system is currently operating at or near full capacity, and is under increasing stress. The robust activity in the wholesale power market is pressuring Bonneville to run the system harder and for patterns of transactions for which it was not designed. This is making it more difficult to schedule maintenance and construction activities. In addition, there is serious concern that the transmission system will not have the capacity necessary to handle the new generation in the Northwest that is needed to bring supply and demand back into balance. Bonneville's access to additional borrowing authority is necessary to ensure long-term system reliability for the Northwest and the entire West Coast.

The Council also supports additional borrowing authority for improvements, additions and replacements at hydroelectric facilities within the FCRPS and the fishery mitigation projects associated with them. In 1992, Congress gave Bonneville the authority to enter into direct funding agreements with the Corps of Engineers and the Bureau of Reclamation for upgrades at their hydroelectric projects. Bonneville has a similar direct funding agreement with the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan hatcheries. These agreements preclude the need for congressional appropriations for these activities, but increase Bonneville's capital borrowing requirements. The Council recognizes this need and supports new borrowing authority to increase the efficiency and reliability of the FCRPS and minimize system impacts on fish and wildlife.

The electricity crisis has also highlighted the importance of vigorous and sustained energy conservation efforts in the Northwest. Unfortunately, during the 1990s, Bonneville's level of investment in conservation decreased substantially due to the emerging competitive electricity market and financial uncertainties. The consequences of this change in policy have been exposed by the astonishingly high electricity prices that we've experienced this past year. Accordingly, it is important that Bonneville regain its leadership in assisting regional utilities and other customers to invest in cost-effective conservation measures while recognizing the market realities of the evolving wholesale power supply market. Additional borrowing authority will allow Bonneville to stimulate such investments throughout the Northwest.

The Council believes that increases in borrowing authority should be accompanied by a high level of accountability in the utilization of the funds. Because the electric ratepayers of the region repay these investments, and because the transmission system supports transactions by several non-federal entities, there is a need to ensure adequate regional participation and oversight in the projects pursued. An open, independent process should be established that identifies least-cost solutions and prioritizes investments that result in a completion schedule of projects. The results of such a process should be included in Bonneville's annual budget submittal for an additional level of accountability. The Council is available to participate in such a process in any way deemed appropriate by the regional entities.

Thank you for your attention to his matter, and please do not hesitate to contact me if you have any questions or comments.

Sincerely,

Frank L. Cassidy, Jr.
Chair

Identical letter sent to: The Honorable Spencer Abraham, Secretary of Energy
Members of the Northwest congressional delegation
House and Senate Committees on Appropriations

STATE OF WASHINGTON

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

1300 S. Evergreen Park Dr. S.W., P.O. Box 47250 • Olympia, Washington 98504-7250

(360) 664-1160 • TTY (360) 586-8203

July 11, 2001

RECEIVED BY BPA ADMINISTRATOR'S OFC-LOG #: 01-0379
RECEIPT DATE: 7·16·01
DUE DATE:
INFO ONLY

INFO ONLY: A-7, D-7, KN/Wash, L-7, P-6, PG-5, KE-4, DF-2, T/Dit2, Cindy Custer-KR/WSGL

The Honorable Spencer Abraham, Secretary
Department of Energy
Forrestal Building
1000 Independence Ave. SW
Washington D.C. 20585

Dear Secretary Abraham:

We write to express our support for the Bonneville Power Administration's (BPA) request for an increase to its borrowing authority from the U.S. Treasury. BPA estimates that infrastructure projects necessary to improve transmission capability and hydropower efficiency will require approximately $2 billion in additional borrowing authority.

BPA is a integral and essential part of both the generation and the transmission infrastructure in the Northwest. It owns and operates about 75 percent of the high voltage transmission in our region. Those transmission facilities are currently operating at or near capacity levels. Additional transmission capacity is needed to allow for the integration of new electricity generation facilities that are being proposed to meet growing demand in Washington and throughout the Northwest. BPA needs to make increased capital investments soon not only to integrate this new generation, but also to preserve the reliability of the existing transmission system.

The Federal Columbia River Power System (FCRPS) contributes about 40 percent of the region's firm electricity generation. Many of these hydroelectric facilities are 40 years or more old and need updates and improvements to maximize their efficiency. BPA informs us that with increased investment in these facilities it will be possible to increase generation capability by as much as 300 aMW. These investments are cost-effective -- they will return more than the cost of capital -- and would contribute importantly to the region's need for new generating capability.

In March of this year, the Federal Energy Regulatory Commission (FERC) identified infrastructure enhancements in transmission and hydropower efficiency as critical to meeting the growing power needs of the West.[1] We believe that BPA's request for additional borrowing authority will permit it to undertake projects that address the problem FERC has identified. Given the recent unprecedented upward pressure on BPA rates caused by runaway prices in the wholesale power market, we are concerned that needed infrastructure investments may not happen in a timely manner without this additional borrowing authority.

We urge your support of the additional borrowing authority requested by BPA. Thank you very much for you help and attention.

Sincerely,

Marilyn Showalter, Chairwoman
Washington Utilities and Transportation Commission

Richard Hemstad, Commissioner
Washington Utilities and Transportation Commission

Patrick Oshie, Commissioner
Washington Utilities and Transportation Commission

cc: Stephen J. Wright, Acting Administrator, BPA
The Honorable Senator Patty Murray
The Honorable Senator Maria Cantwell
The Honorable Representative Jay Inslee
The Honorable Representative Rick Larsen
The Honorable Representative Brian Baird
The Honorable Representative Doc Hastings
The Honorable Representative George R. Nethercutt, Jr.
The Honorable Representative Norman D. Dicks
The Honorable Representative Jim McDermott
The Honorable Representative Jennifer Dunn
The Honorable Representative Adam Smith

[1] *Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States and Requesting Comments on Further Actions to Increase Energy Supply and Decrease Energy Consumption.* Docket #EL01-47-000. Federal Energy Regulatory Commission. March 14, 2001.

JOHN A. KITZHABER, M.D.
GOVERNOR

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG #: 01 · 0380
RECEIPT DATE:
7·17·01
DUE DATE:
INFO ONLY

July 16, 2001

The Honorable Robert C. Byrd
Chairman Interior Subcommittee
Senate Committee on Appropriations
SH 123 Hart Senate Office Building
Washington, D.C. 20510-6033

INFO ONLY: KR-7C
cc: A-7, D-7, KN/Wash, KR-7, L-7, P-6, PG-5, KE-4, DF-2, T/Ditt2, Cindy Custer-KR/WSGL
Anne Morrow KR-7C

Dear Mr. Chairman:

I am writing in support of the Bonneville Power Administration's request for an additional $2 billion in borrowing authority from the U.S. Treasury. The additional authority is needed for critical investments in the Northwest's high-voltage transmission system and hydroelectric facilities.

Bonneville owns and operates about 75 percent of the Northwest's high-voltage transmission. Its system is now at or near capacity. As a result, the system cannot carry all the electricity generated from new power plants coming on line. Bonneville must make substantial investments in new transmission capacity to ensure the continued reliability of the Northwest power system.

Also, Bonneville supplies about 40 percent of the electricity used in the Northwest. Most of that supply comes from hydroelectric facilities – many of which are old and need improvements to achieve full efficiency. With added borrowing authority, Bonneville can upgrade these facilities and increase supply by an amount equivalent to the output of a new power plant. In a power-short region, these are needed, timely investments.

urge you to support Bonneville's request.

Thank you for your consideration of this matter.

Sincerely,

John A. Kitzhaber, M.D.

Oregon Delegation
Steve Wright, Acting Administrator, Bonneville Power Administration

City of Seattle
Paul Schell, Mayor
Seattle City Light
Gary Zarker, Superintendent

RECEIVED BY BPA ADMINISTRATOR'S OFC LOG #: 01-0583
RECEIPT DATE: 7.18.01
DUE DATE:
INFO ONLY

July 17, 2001

INFO ONLY: A-7, D-7, KN/Wash, L-7, P-6, PG-5, KE-4, DF-2, T/Ditt2, Cindy Custer-KR/WSGL

Robert C. Byrd
Chairman, Senate Committee on Appropriations
311 Hart Senate Office Building
Washington, DC 20510

Chairman Byrd:

As you know, the Bonneville Power Administration (BPA) has sought a $2 billion increase in borrowing authority to primarily finance transmission expansion projects in the Pacific Northwest. The current language in the Energy and Water Appropriations bill authorized $2 billion, but makes spending subject to annual appropriation. I urge you to support in conference language approved the Energy and Water subcommittee that does not condition bonding authority on the annual appropriations process.

I believe that the Northwest, like many parts of the country, has under-invested in transmission. Much of that is attributable to uncertainty over industry structure and cost recovery. Much is also attributable to a surplus of generation and transmission capacity along the West Coast. The problems of the last year have made us acutely aware of the need for substantial investment in generation and transmission by public utilities, private utilities, independent power producers, and Bonneville.

The principal difficulty with an annual appropriations process is that it prevents investments in capital intensive, long-lead time transmission projects. Substantial investments are needed immediately to address congested paths in Puget Sound. We have been subject to a number of transmission curtailments this year that prevent our access to power from Boundary dam. Investor owned utilities in the northwest have faced the same problem – the "west of Hatwai" problem – bringing in power from generation they own in Montana and Wyoming. Northwest congestion greatly impairs our ability to assist California in summer, and vice versa in winter. In addition to relief of congested paths, Bonneville must add transmission capacity to support new generating projects being built in the region. We believe that we cannot wait for the formation of a FERC-jurisdictional Regional transmission Organization to decide on a perfect expansion plan.

I do share the concern of Northwest investor owned utilities that BPA investments address top priority problems in a cost-effective manner. They should focus on interconnecting generation and resolving congestion in projects that are not likely candidate investments for other parties. A technical review committee can provide guidance on these issues to the Administrator.

I'd like to reiterate my support for an energy and water appropriations bill that includes $2 billion in increased BPA borrowing authority, not subject to authorizations on an annual basis. I would be delighted to answer any questions you have on this issue.

Sincerely,

for Gary Zarker
Superintendent

JH:smb

cc: Senator Patty Murray
Senator Maria Cantwell
Representative Jay Inslee
Representative Rick Larsen
Representative Brian Baird
Representative Doc Hastings
Representative George Nethercutt
Representative Norman Dicks
Representative Jim McDermott
Representative Jennifer Dunn
Representative Adam Smith

Robert P. Gannon
Chairman of the Board,
CEO and President

The Montana Power Company

July 12, 2001

Chairman Robert C. Byrd
Senate Committee on Appropriations
311 Senate Hart Office Building
Washington, DC 20510

Dear Chairman Byrd:

I am writing to express Montana Power Company's support for increasing the borrowing authority of the Bonneville Power Administration (BPA) to facilitate the construction of additional electric transmission facilities. This funding is critically important to improve the capacity and reliability of BPA's transmission system for the benefit of consumers throughout the Pacific Northwest.

I am pleased that BPA has recently agreed to form a review committee with its transmission customers to assure that transmission improvements are prioritized so as to provide the most cost-effective and reliable service for the region. Montana Power will gladly participate in the important work to be undertaken by this review committee. It would be appropriate for language supporting the formation of this committee to be included in your Committee report.

Montana Power has been, and continues to be, concerned about BPA's program to install fiber optic cable far in excess of BPA's legitimate operational requirements. I encourage the Committee to carefully review any additional funding that BPA may request for this purpose.

If you or your staff have any questions about Montana Power's support for additional BPA borrowing authority, please contact Bill Pascoe, Montana Power's Vice President, Energy Supply at (406) 497-4212.

Sincerely,

Robert P. Gannon

40 East Broadway Street • Butte, Montana 59701-9394
Telephone: 406-497-2403 • Facsimile: 406-497-2150 • e-mail: rgannon@mtpower.com

CC: Senator Conrad Burns
Senator Max Baucus
Representative Dennis Rehberg
Governor Judy Martz
Senator Ted Stevens
Senator Pete Domenici
Senator Patty Murray
Senator Larry Craig
Representative Sonny Callahan
Representative Peter Visclosky
Secretary Spencer Abraham
Stephen Wright – Acting Administrator, BPA

Public Power Council
1500 NE Irving, Suite 200
Portland, Oregon 97232
(503) 232-2427
FAX (503) 239-5959

October 15, 2001

Mitchell E. Daniels, Jr.
Director
Office of Management and Budget
725 17th Street NW
Washington, D.C. 20503

Dear Mr. Daniels:

On behalf of the 114 Northwest consumer-owned utilities that are members of the Public Power Council (PPC), I am writing to express our support for increasing by $2 billion the amount of funding that Bonneville Power Administration (BPA) may borrow from Treasury. PPC supports this increase for three reasons:

1. The region's transmission system, 75% of which is owned by BPA, is now heavily constrained, and the problem will worsen unless dramatic steps are taken soon. BPA has not made substantial upgrades to its transmission facilities for well over a decade despite rapid growth in the Northwest. Considerable amounts of new generation are planned for the Northwest. While new generation will benefit all 11 western states, it must be connected to a reliable transmission grid. Building and maintaining the needed transmission infrastructure requires BPA to make significant capital investments. BPA's current borrowing authority is insufficient to fund the needed investments. (We are aware that the Administration is considering conditioning BPA's borrowing authority for transmission upon solicitation of third-party partners. We urge you to ensure that any third-party financing or ownership be available to *all* potential participants, including consumer-owned utilities, and that participants be selected on the basis of lowest bid so that we do not "bid-up" the cost of regional transmission assets.)

2. From the 29 federal hydroelectric projects, BPA markets nearly half of the electricity consumed in the Northwest. The energy available from these projects declined during the 1990s due to deferred maintenance, and it is time to restore the full capability of the hydro system. Restoring this capability will provide more energy to the western energy market at a cost below that of constructing new generation, and will provide additional capacity needed to keep the lights (and heat) on in the event of an "Arctic Express" cold weather event. BPA's current borrowing authority is insufficient to fund the needed investments.

3. BPA has committed to a significant conservation effort to help meet its existing resource shortfall. We expect BPA to use capital for conservation only when necessary to ensure that cost-effective conservation investments take place, limited to those investment costs customers and utilities are unable to make on their own, and with the assurance that the investment creates an actual reduction in BPA's need to make power purchases. BPA's current borrowing authority is insufficient to make these investments.

These investment projects are complex, and involve long-term planning, access to capital and a long-term funding commitment. BPA likely will exhaust its current borrowing authority, which was last increased in 1984, as early as 2003. BPA, in concert with the region, must plan now to meet the needs of the future. It cannot do so in a prudent or business-like manner without a stable source of capital. We urge you to support BPA's request within the Administration and before Congress.

Sincerely,

C. Clark Leone
Manager

Financial Choices closeout

BPA Talking Points
Nov. 22, 2002

On Nov. 22, BPA Administrator Steve Wright completed BPA's Financial Choices dialogue with the region by announcing his decisions on how the agency will address its revenue shortfall during the current rate period. For more information, call Chuck Maichel at (503) 230-7496.

Background

In July 2002, BPA initiated a Financial Choices public process to solicit comments and recommendations on ways in which the agency should resolve a projected $860 million revenue shortfall (which had grown to $1.2 billion by October) during the current rate period (through FY 2006). To help the discussion, BPA outlined several approaches to closing the revenue deficit that ranged from raising rates to cutting costs, to reducing Treasury payment probability, to using cash management tools to push costs into the future.

As part of the public process, BPA sponsored a series of public meetings and workshops during August and September. A primary goal of the public meetings was to have customers, interest groups and others enter into a dialogue with each other over values. The workshops provided the opportunity for interested parties to delve more deeply into the details of the current BPA financial situation. By the time the process ended, BPA had received thousands of comments from organizations and individuals.

On Nov. 14, Administrator Steve Wright outlined the agency's cost management effort for the balance of the rate period. Talking points, revised on Nov. 15, explain that effort. After those "highly probable" reductions and the impact of the financial-based cost recovery adjustment clause for FY 2003-2006 are taken into consideration, the agency still faces a projected revenue shortfall of about $500 million. How that gap is to be closed is explained in these talking points.

Messages

- The message BPA received during the Financial Choices process is that the state of the regional economy requires that BPA emphasize cost reductions as the best way to help the agency solve its revenue shortfall and to continue to provide benefits to the region.

- BPA has reduced internal operating costs covered by power rates to below FY 2001 actual spending levels with no allowance for inflation.

- Despite the expense reductions taken and the projected effect of the financial-based cost recovery adjustment clause (FB CRAC) rate adjustments for FY 2004-2006, the agency still forecasts a shortfall of about $500 million over the remainder of the rate period. The magnitude of the shortfall is most significantly affected by the revenue BPA earns from net secondary power sales. Because these revenues are based on water and market price conditions, which are volatile, they represent significant uncertainty.

- In excess of $500 million of potential expense reductions, expense deferrals and other actions are under discussion. The largest possibilities are in the areas of the public/investor-owned utility litigation, and fish and wildlife programs.

- The call on whether the safety net CRAC (SN CRAC) will trigger in FY 2003 is very close. The administrator has decided to wait until more information about this winter's water situation and about secondary power prices is available before making a decision. That decision will come after the first of the year.

Questions and answers

FINANCIAL GAP

1. What is the financial gap that BPA is talking about closing?

Because of lower-than-expected revenue from secondary power sales in FY 2002 and the continuing effects of the FY 2001 drought, the Power Business Line is experiencing a gap between its total FY 2002-2006 revenues and expenses. In May of this year, that gap was projected to be $860 million dollars for the FY 2002-2006 rate period. As of October, the gap was expected to be about $1.2 billion.

2. Why has the gap grown?

Several things changed after the May 2002 forecast — market prices for secondary energy dropped in FY 2002 and have remained low; the hydro energy forecast was updated for FY 2002-2006; and the agency acknowledged that it will have to recognize some payments due to the agency as bad debts (that is, as possibly uncollectible).

RATES

3. Why have BPA's rates increased?

BPA implemented a 46 percent wholesale power rate increase in October 2001 that, with an adjustment six months later, resulted in an average of 43 percent for the year. The increase was driven primarily by major increases in public benefits to the region.

- BPA had to augment its power supply, which meant buying power in the market when the cost of power was very high, to meet firm customer requirements that exceed our firm resources. Two years ago, we responded to regional demands for power and committed to provide approximately 3,000 average megawatts more than our firm resource base could produce. While BPA's costs for augmentation are reasonable — averaging $35 per megawatt-hour — the sheer volume added significant costs.

- Payments to investor-owned utilities for their residential and small-farm customers increased from $70 million a year in FY 2001 to about $400 million a year currently. That reduced the need for rate increases in some IOU service areas but adds over $2 billion to BPA expenditures that must be collected from rates over the five-year rate period.

- BPA increased its spending for fish recovery by nearly $100 million a year over pre-2002 levels.

- BPA increased its spending on conservation and renewable resources, much of which supported system augmentation needs.

- The agency initiated programs to assure planned availability, high reliability and safety for the hydro system and for Columbia Generating Station, which increased costs over initial forecasts.

While costs were going up, revenues were decreasing. Power markets provided lower-than-projected net secondary (surplus power sales) revenues. When we completed the rate case in June 2001, we expected FY 2002's secondary power prices to average around $55 a megawatt-hour, a conservative estimate at the time, but market prices have continued to drop. They averaged about $24 per megawatt-hour for FY 2002. The agency also began FY 2002 with less water than usual. Refilling Canadian storage after the drought of FY 2001 and the dry fall in FY 2002 caused a loss of generation, which further reduced secondary power revenues.

4. What is the overall effect of the cost cuts on rates?

The agency has two general categories of cost cuts – the highly probable and the still under discussion. The highly probable cuts have helped BPA avoid triggering the SN CRAC for now. The still-under-discussion reductions could affect a specific CRAC depending on whether it is an expense reduction, a deferral or other action.

5. So a safety net CRAC is still a possibility?

Yes. We are continuing to aggressively pursue cost reductions that could help the agency close its revenue gap, but the most significant near-term factor is the amount of revenue the agency can realize on the secondary power market. The agency currently has slightly greater than a 50 percent probability of making all payments in FY 2003 assuming we have an average water year and sell our secondary power for an average price of about $30 per megawatt-hour. Less water or lower prices could easily bring us under the 50 percent trigger.

We will continue to pursue cost cuts and monitor the water situation and market prices. Snowpack and runoff projections will be available in January so we plan to assess our Treasury payment probability for FY 2003 after that information is available.

6. Does this mean rates will not go up any time between now and the end of FY 2006?

No. At the very least there will be seasonal fluctuations in the load-based cost recovery adjustment clause. For example, the LB CRAC adjustment is forecast to increase 8 percentage points in April 2003 over the adjustment currently in effect. Total rates in April are expected to be about 50 percent above the May 2000 base and will be made up of a 39 percent LB CRAC and an 11 percent FB CRAC. Variability will continue for the different LB CRAC periods because the LB CRAC tends to be higher in the spring/summer period compared to fall/winter.

SECONDARY POWER SALES REVENUES

7. Why is the secondary power market so important?

The crucial difference from the rate case was the much-lower-than-expected price for secondary power in FY 2002. We used what was then (when prices averaged over $200 per megawatt-hour) considered to be a very conservative estimate of $55/MWh for FY 2002 in the rate case, but prices ultimately averaged $24/MWh for the year.

Our net revenue forecast for FY 2003-2006 assumes that wholesale prices will go up over the rest of the rate period compared to what we received last year and that we will have an average water year. This makes our financial condition heavily dependent on the price of energy and on water conditions. These forecasts are based on the best available information and analysis, but, as with any forecast, there is much uncertainty.

COST REDUCTIONS

8. What is the current total cost reduction for the PBL over the rest of the rate period?

At the moment, BPA has identified about $350 million in cost reductions over the FY 2003-2006 period. This is made up of approximately $220 million in expense reductions, $72 million in potential expense deferrals and about $56 million in free ups of Energy Northwest (ENW) reserve funds.

9. Where are the FY 2003-2006 reductions coming from?

Internal operating reductions account for $136 million of the total — $107 million from the PBL and $29 million from Shared Services and Corporate costs assigned to the PBL. That brings those internal operating costs down to less than FY 2001 actuals with no allowance for inflation.

This has been accomplished by freezing almost all outside hires and significantly reducing travel, training, retention allowances, employee rewards, contract employees, consultant contracts, market research, research and development and other costs. For a limited time, BPA is offering employees incentives to separate from BPA and to take early retirement.

Energy Northwest has reduced its expense forecast by $15 million and, in addition, is deferring costs out of this rate period by delaying the condenser tube replacement project indefinitely and modifying its fuel procurement strategy to use the fuel it currently has in stock and to replenish the supply in ENW's 2007-2009 fiscal years. BPA intends to restructure the Performance Incentive Fee Program with ENW so that payments come out of cost reductions below the expense target. We will continue to work with ENW, through benchmarking and other activities, to seek additional cost reductions consistent with safe and reliable operation of the Columbia Generating Station.

While we are committed to a sustainable energy efficiency future, we think we can meet the Northwest Power Planning Council's target for conservation acquisition at a reduced spending level. In fact, we think we can hit that target at about half our earlier projected costs. We will be reducing our research and development efforts in areas such as the Energy Web where we have eliminated planned spending increases. We will continue to sustain renewable power generation development by concentrating more on facilitating purchases by others rather than on a BPA-only acquisition program.

10. Are further reductions possible?

Yes. But BPA has much less control over the remaining potential reductions. Areas for further exploration include reducing benefits paid to investor-owned utilities for their residential and small-farm customers, which requires the agreement of the utilities receiving the benefits as well as public utility commissions; reductions through enhancing the cost effectiveness of fish and wildlife programs, which BPA is exploring in partnership with other federal agencies, the Northwest Power Planning Council and the public; and potential changes in higher-priced energy purchase contracts.

We are also looking at ways to operate the Federal Columbia River Power System and manage the direct fish program more efficiently and at less cost.

11. How much do you hope to save from these further reductions?

In excess of $500 million if all of them work out.

12. How close are you to closing the PBL's net revenue gap?

With the reductions that are highly probable, the gap of $1.2 billion has been reduced to about $900 million. The reduction came from $220 million in expense reductions and $72 million in expense deferrals. The $56 million in other actions does not reduce the power net revenue gap; it is a tool to help make our Treasury payment.

With the maximum financial-based CRAC adjustments for FY 2004-2006 of about $330 million added to the reductions, the expected gap should be down to the $500 million neighborhood. The still-under-discussion items are mostly rate-specific or cash-specific items that will not close the revenue gap.

13. What is the effect of all these reductions, the highly probable and those still under discussion, on current rates?

After April 2003 we expect the load-based CRAC adjustment to go down from current levels for the remaining rate period as power purchase contracts expire. It will, however, still have seasonal fluctuations. We expect the financial-based CRAC adjustments to remain at their annual maximums if expenditures are not further reduced and if an SN CRAC is not triggered.

14. Why didn't the Power Business Line reduce staff extensively to save costs?

During the mid-1990s, the agency aggressively used voluntary separation incentives and early retirement offers to reduce staff. By FY 1999, the PBL had reduced its staff by almost 30 percent over 1994 levels. The PBL staff grew by 4.5 percent between its low in FY 1999/2000 and FY 2002 in response to the PBL's more complex work and the need to train new employees to assume the positions of employees who will be retiring soon. The expectation is that the business line staffing will gradually decline over the next few years as people retire.

The agency is currently offering incentives to encourage employees to retire by the end of this calendar year. The only way to radically reduce staffing in a federal organization is to conduct a reduction in force. That is a cumbersome process that would not produce any reduced staffing numbers for at least a year and, because of its chaotic nature, would leave the organization much weaker than it can stand to be to meet the current challenges.

15. Why do BPA's internal operating costs have offsetting revenues?

The PBL Efficiencies Program is a good example of how this works. The program began in FY 1999 in response to the Cost Review to improve overall efficiencies to maximize performance. Components of the program include, among other programs, the Near Real Time Optimization project to develop computer tools to evaluate the distribution of generation over the federal hydro system within each hour and the Columbia Vista software to make more efficient use of water. Each of these programs can increase the revenue generated from the hydro system. These are just some examples of how internal costs can be viewed as investments that show a return.

16. What is the result, so far, of the Financial Choices review of BPA's fish and wildlife program budget?

BPA's Division of Fish and Wildlife has undertaken a review of how we conduct business as we implement our obligations to the region's fish and wildlife resources under the Northwest Power Act, the Endangered Species Act and other applicable laws. It is clear that the region can significantly improve the effectiveness of the Integrated Program. With BPA confronting one of the most significant financial challenges in its history, our need to act on these improvements has taken on an even greater sense of urgency. BPA's financial situation also places on us a requirement to look for ways to effectively manage the costs of fish and wildlife investments without compromising the substance of our efforts.

Beginning with the FY 2003 start-of-year budget, BPA implemented the following changes:

- BPA is moving from obligation-based to accrual-based budgeting because the latter provides much greater accuracy in estimating the costs that will actually be incurred in a given fiscal year and results in more cost-effective implementation of programs.
- Funds will not be carried over to the next fiscal year unless they are specifically justified on a case-by-case basis. If certain planned tasks are not performed within a given year, for whatever reason (weather, lag time in hiring personnel, equipment failure, National Environmental Policy Act delays and the like), the contractor should not expect to receive these funds without additional review.
- If the accruals for a project exceed the amount budgeted for that year, then funds will have to be taken from other projects to cover the added cost.

17. How will this affect the renewal process for fish and wildlife contracts?

Fish and wildlife contractors will be required to use the following standards when preparing budgets for FY03 contract renewal:

- Eliminate the 10 percent rule that enables "budget creep" above an approved project budget.
- Eliminate all "carry over" (contracted project balance). Set FY 2003 budgets consistent with BPA decision document/Northwest Power Planning Council recommendations, which are similar in most instances.
- Eliminate the 3.4 percent cost of living adjustment (COLA) rule. For the interim until we have an agreed upon SOY FY 2003 Budget, use the BPA FY 2002 contracted amount for FY 2003 rather than assuming any amount for a COLA.
- Include a section in the statement of work (SOW) that explains/details the travel and potential training costs in the budget. These must be directly connected to the project proposal as submitted in the Provincial Review Process and as recommended by the Council.
- Travel must be associated with implementation of the project and clearly explained in the SOW and detailed in the budget.

- Training must be essential for implementation of the project and specifically identified in the project proposal. There must be a clear tie between the training and the work described in the objectives and tasks.
- Conferences will not be paid for under BPA contracts. All conference attendance and associated travel is to be covered by the contractor.
- Scrutinize housing and equipment purchases to achieve scope of the project.
- Extend the life cycle of equipment such as computers, printers, vehicles, boats, etc. In other words, postpone replacement of this equipment as long as possible without jeopardizing safety and/or project scope integrity.
- For additional information, see the BPA external Web site at http://www.efw.bpa.gov/cgi-bin/FW/budgetandcontractrenewal_fy03.cgi

18. How are efficiencies in river operations being addressed?

In September and October 2002, the action agencies (BPA, the U.S. Army Corps of Engineers and the Bureau of Reclamation) together with the National Marine Fisheries Service and the U.S. Fish and Wildlife Service jointly reviewed configuration, spill and flow operations to see whether modifications or changes could be made that would sustain or accelerate progress in achieving hydro performance standards but potentially reduce hydrosystem operational costs. Several alternatives that warranted further evaluation and discussion with the region were identified. The NMFS Regional Forum teams will discuss these alternatives over the next several months, with decisions in early 2003 on actions to be implemented. The alternatives under discussion include:

- Accelerate installation of removable spillway weirs and behavior guidance systems at Ice Harbor and Lower Monumental dams.
- Accelerate installation of a forebay physical guidance device at The Dalles Dam.
- Discontinue spill at Bonneville Dam to assist passage of Spring Creek hatchery release in March.
- Eliminate daytime spill testing at John Day Dam in the spring.
- Test alternative levels of nighttime spill at John Day Dam in the spring.
- Modify spill at Ice Harbor Dam to optimize tailrace egress.
- Assess whether operations to maintain flows to benefit chum salmon should be consistently maintained through emergence in low water years.

19. Why didn't the agency use the funds it received from refinancing ENW bonds to cover current operating costs and reduce the chance of a rate increase?

BPA has been implementing a two-part debt optimization plan. In the first part, BPA has refinanced and extended the principal on some ENW bonds, resulting in lower ENW payments. In the second part, BPA has paid off the same amount of Treasury debt (about $190 million through FY 2001 and $266 million in FY 2002). The principal paid in advance to Treasury is equal to the principal originally owed by ENW/BPA.

The intent of the debt optimization plan is to replenish the agency's borrowing authority (by reducing the amount of outstanding federal debt) while reducing the costs to regional ratepayers of BPA's debt portfolio without compromising BPA's future financial viability. If we break our agreement with ENW, we will jeopardize further refinancings — and these possible future refinancings hold the promise of additional benefits for the region in the form of cost savings and replenishment of BPA's borrowing authority.

20. Why not tell the Treasury that the funds sent to retire Treasury bonds are actually an early payment toward the agency's FY 2003 Treasury payment?

Our current plan for FY 2003 is to pay the full scheduled amount of amortization (the schedule is determined by repayment studies included in our Transmission and Power Rate Proposal FERC filings), and additionally pay advance amortization equal to the amount of ENW principal originally due in 2003 that is extended to future years. BPA believes this is the fiscally prudent approach, one that has many benefits for the region.

There are several problems with proposing that we not pay our full scheduled amortization payment but, rather, apply prior advance amortization payments to the scheduled payment. The first is that some of the 2003 payment is due, that is, the appropriation or bond has a final due date in FY 2003. Any such obligations must be repaid in FY 2003.

The second is that, while we have been and are still engaged in discussions with the Treasury with the goal of understanding how it views these advance amortization payments, to date it has stated it "would not favor" allowing recognition of the advance payments in lieu of paying the full scheduled amount of amortization in any year in light of the fact that we have the option to defer payments. To plan on not making full payment without prior Treasury concurrence poses considerable risk of political backlash to BPA.

The third is that, to the extent that the early amortization payments were made as part of the debt optimization program, it violates the principle and prudent financial policy of not increasing the overall amount of debt outstanding due to the debt optimization program. BPA follows a principle of increasing its debt only to pay for increases in its assets.

21. What is the effect of settling the $200 million public/IOU litigation?

BPA can do very little to influence the settlement of the IOU litigation at this time. Puget Sound and PacifiCorp are the two principal IOU parties involved in the dispute. A resolution between the publics and these two utilities would need to take place before BPA can recognize these cost reductions. In the event the $200 million were eliminated, the result would be a reduction in the LB CRAC of approximately 5 percent from FY 2002 average rates.

22. What can we do to reduce our exposure to high-priced power contracts?

Early on, we canceled the contracts that we were legally able to. The agency also has asked the Federal Energy Regulatory Commission to continue its investigation of market manipulation and to, if it finds entities have engaged in manipulative practices, impose appropriate remedies such as termination of contracts. We are also in direct discussion with the companies with whom we have the contracts.

"CASH TOOLS," DEFERRALS AND OTHER RISK MANAGEMENT TECHNIQUES

23. What are "cash tools" and how do they affect net revenue?

The term cash tools has a variety of meanings. Generally, cash tools don't affect revenue or expenses but do affect BPA's liquidity. If they don't affect revenue or expenses, they don't close the net revenue gap. They can, however, help BPA make its Treasury payment and meet its other financial obligations. Generally, cash tools merely postpone costs, shifting them to a later year or to subsequent rate periods. We do not believe it is prudent to plan to shift costs into the future. We plan to keep the additional cash tools we have available for use on a real-time basis in case of unforeseen adverse circumstances.

24. Could deferring expenses potentially increase rates in the post-2006 period?

To the extent we defer costs to the next rate period, our rates in that period will be higher than they otherwise would be. We are being careful to limit how much we are deferring to the post-2006 period. It is a matter of balancing what we think will be reduced expenses and increased revenues in that period with a certain amount of costs from the current period. We really don't want to shift operating expenses into the future; that is not a prudent business practice.

August 20, 2002

Addressees

Subject: Infrastructure Technical Review Committee (ITRC) Report

Background

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U.S. Department of Energy, May, 2002).

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority as well as full consideration of third-party financing options. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The ITRC was formed in 2001 at the behest of some BPA customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Each year, the ITRC evaluates and works to prioritize BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. Guidelines for the review were defined in the "Agreement for Annual Review of Major BPA Transmission Investments" dated July 18, 2001 and with a update added on January 15, 2002 (attached). The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC) and the Operating Committee (OC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting a report on proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not finance the work of the ITRC.

Borrowing Authority

The committee provided its first report on August 30, 2001 with the recommendation that BPA install necessary system facilities as soon as possible. A critical first step was BPA securing additional borrowing authority. The additional borrowing authority was not approved last year. Unless additional borrowing authority is approved this fall some needed projects will be delayed, putting reliability at risk and inhibiting construction of new generation. The resulting congestion and reduced capacity margins will lead to higher prices and increased market volatility.

Projects G10-G14

Attached is the second annual report on the transmission infrastructure proposal that contains BPA's conclusions and recommendations to the review committee. The report addresses four additional projects. The committee supports BPA's findings as summarized below:

- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G11 (South Seattle Transformer) will be submitted for future review.
- Project G12 (Olympic Peninsula Reinforcement) is also important. The need date to prevent area problems for first contingency (N-1) outages is later than initially estimated based on the most recent load forecasts. Planned and controlled loss of area load is permitted under the NERC/WECC Planning Standards for the exposure to double contingency (N-2) and bus outages provided that system cascading does not result. Opportunities for non-transmission alternatives are being pursued in parallel with the proposed transmission fix.
- Project G13 (Paul – Troutdale 500-kV Line) will continue to go through the WECC Regional Planning Process this year in expectation that it will be ready to be considered by the ITRC in 2003.
- Project G14 (Hanford-Ostrander 500 kV loop-in) requires further analysis by BPA.

Some members of the ITRC believe that projects G12 and G13 should be accelerated.

Additional Comments

- Projects reviewed in prior years will not be extensively re-reviewed unless circumstances have changed significantly. The projects are subjected to other technical reviews (i.e., TPC, NRTA, WECC) as appropriate. BPA should provide status reports to the ITRC.
- Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure firm transmission service contracts of sufficient duration and with appropriate credit provisions before proceeding with construction.

BPA is requested to continue conducting annual reviews to evaluate and prioritize proposed major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers.

Ken Morris
PacifiCorp

John Martinsen
Snohomish PUD

Wayman Robinett
Puget Sound Energy

Hardev Juj
Seattle City Light

Scott Waples
AvistaCorp

Ronald Schellberg
Idaho Power Company

John Leland
NorthWestern Energy

Jim Eden
PGE Company

cc
Infrastructure Technical Review Committee

Upgrading the Capacity and Reliability of the BPA Transmission System

Report to the Infrastructure Technical Review Committee

August 20, 2002

Table of Contents

Appendices

Please refer to the August 30, 2001 Infrastructure Review Committee report for information on the purpose of this Committee, terms of engagement and general system need. Also please refer to this report for system maps.

1.1 Background

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002). Problems with transmission in the region are manifested in several ways:

- Chronic congestion existing on a number of transmission paths requires curtailment of both firm power deliveries and economy energy.
- Continued resolution of the Western energy crisis requires development of new generating resources. The vast majority of proposed Northwest resources cannot obtain firm transmission service, or be integrated, without additional Bulk Transmission.
- It is extremely difficult to meet obligations when facilities are removed from service to conduct normal maintenance or to construct new facilities.
- While power loads have been growing steadily at 1.8% annually and the use of the transmission system is up by over 2% annually, few Bulk Transmission lines were added in the past 15 years.
- It will take much longer to site and build transmission to deliver needed new generation than it will take to build and site the generation. New transmission is needed to meet statutory, treaty and contractual obligations and comply with national and regional standards that ensure a reliable power system[1].

As the operator of three-quarters of the Bulk Transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The Infrastructure Technical Review Committee (ITRC) was formed in 2001 at the behest of some of BPA's customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Once a year, the ITRC evaluates and prioritizes BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC), Operating Committee (OC) and the Northwest Regional Transmission Association (NRTA) Planning Committee (PC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not fund the work of the ITRC.

The committee was asked to report its initial recommendations by August 30, 2001 to enable BPA to install necessary system facilities as soon as possible.

This review is the second in an annual process to coincide with BPA's annual budget cycle. It covers four projects of BPA's infrastructure proposal. Review of additional projects will be conducted in subsequent years. There are several additional parallel efforts that provide for review of proposed transmission additions. This committee's analysis and recommendations will be shared and further analyzed in the following forums.

- Northwest Power Pool (NWPP) Transmission Planning Committee
- Western Electricity Coordinating Council (WECC) Regional Planning Group
- National Environmental Policy Act (NEPA) review for individual projects

During the first part of 2002 the committee met twice to review additional infrastructure proposal developed by BPA. While some of the proposals have been under development in previous forums with outside participation, other proposals were presented for the first time. BPA conclusions and recommendations given on the following pages.

1.2 Projects Reviewed in 2002

There continues to be a compelling and immediate need to complete the projects reviewed in 2001 and to further upgrade portions of the Northwest Bulk Transmission grid. Solutions proposed by BPA in coordination with others address the identified problems. Detailed descriptions are given in Appendix C together with the economic analyses in Appendix D.

- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G11 (South Seattle Transformer) is not addressed at this time and will be submitted for future ITRC review.
- Project G12 (Olympic Peninsula Reinforcement) is also important. The need date to prevent area problems for first contingency (N-1) outages is later than initially estimated based on the most recent load forecasts. Planned curtailment of area load is permitted under the NERC/WECC Planning Standards for the exposure to double contingency (N-2) and bus outages provided that system cascading does not result. Opportunities for non-transmission alternatives are being pursued in parallel with the continued review of the proposed transmission fix.
- Projects G13 (Paul – Troutdale 500-kV Line) and G14 (Hanford-Ostrander 500 kV loop-in) were examined on a preliminary basis. Project G13 is critical to integration of new generation in the I-5 corridor. BPA will complete details of the plan of service over the next 60 days and bring this through the WECC Regional Planning Process. In addition, coordination with PGE and PacifiCorp is required in relation to their respective transmission and generation expansion plans.
- The benefits of project G14 are not clear given proposed I5 generation development and potential higher costs to route around the Columbia Gorge Scenic Area. BPA will bring these projects forward to the committee for consideration in 2003 after further examination of alternatives and need.

Table 1. 2002 Recommended Projects

Project		Capital Cost (loaded) ($M)	Energization Date	Capacity Added MW
Portland Area Additions	G10	9	2003	300
Olympic Peninsula Reinforcement	G12	26	2005	430
Total		35		

Table 2. Drivers for 2002 Recommended Projects

	Load Service	Entitlement Return	Generation Integration	Transfers	Reliability	O&M Savings	BiOp
G10	x				x		
G12	x				x		

1.3 Projects Reviewed in 2001

- Projects evaluated in previous years should continue on the revised timetable proposed by BPA. BPA will continue to reevaluate project need and timelines, particularly for projects driven by generation integration.
- In accordance with provisions in the January 15, 2002 guidelines[2] BPA provided a status report on projects that were reviewed last year. There were no significant changes in circumstances that necessitated any of these projects be returned to the committee for a full review.
- Section 1.5 provides a status report on these projects G1-G9.

1.4 Rate and Budgetary Impacts

As started earlier, there continues to be a compelling and immediate need to continue to upgrade portions of the Northwest Bulk Transmission grid and capital to meet that need.

- Figure 1 illustrates the historical and projected transmission capital requirements forecasted by BPA over a ten-year planning horizon. The capital outlay from 2001 and beyond, including the infrastructure proposals, is well above BPA's remaining borrowing authority. Accordingly, the need still remains to increase BPA's borrowing authority for *transmission* by at least $1 billion in order to ensure that sufficient financial resources are available.
- BPA will continue to pursue and evaluate third-party financing opportunities for major new transmission projects.
- Preliminary analysis for the individual projects show that in some cases the cost will be fully recovered by increased usage and may put downward pressure on rates. Other projects that are driven by reliability needs may put upward pressure on rates. Details on the economic analysis are given in Appendix D. This report is not intended to be a rate projection.
- Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure firm transmission service contracts of sufficient duration and with appropriate credit provisions before proceeding with construction.
- Additional reinforcements by BPA and others are needed to maximize reliability and transfer capability from the proposals. Other Northwest utilities have planned and in some cases committed to transmission additions, and maximum benefits will be achieved through coordinated development.

Future reviews will be conducted annually to evaluate and prioritize BPA proposed major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers.

1.5 Status of Projects Reviewed in 2001

Projects G1-G9 reviewed in 2001 remain in the construction program but in some cases with revised energization dates, or subject to commitments from proposed generation plants. A brief status statement follows on each of these projects:

G1 Puget Sound Area Additions (Kangley – Echo Lake 500 kV Line)
The energization date for this project has set back one year to Fall 2003 to allow a full analysis of alternatives through the environmental process. Based on approval by WECC the outage of the Raver – Echo Lake and Schultz – Echo Lake lines on common rights of way has been granted an exception from two-line outage requirements and reclassified as NERC/WECC Category D (exploratory). The Snoking 500/230 kV transformer energization has also been delayed by one year to Fall 2003.

G2 North of Hanford (Schultz – Wautoma 500 kV Line and Wautoma Substation)
This project is proceeding forward on the Fall 2004 schedule with no change in status.

G3 McNary – John Day 500 kV Line
This project is proceeding forward on the Fall 2004 schedule with financial commitments having been received from generation projects for preliminary design and environmental work.

G4 Lower Monumental – Starbuck 500 kV Line
Need for this project is presently uncertain due to delay of the Starbuck generation project. Continuation of this project will depend on resumed development of this site and agreements for financing of the transmission project.

G5 Smiths Harbor – McNary 500 kV Line
Work is proceeding on plans for construction of the substation at Smiths Harbor based on commitments from the Smiths Harbor generation project. Need for the transmission project depends on plans to move forward with the Starbuck generation project or other generation in the area.

G6 Schultz Series Capacitors
This project is proceeding ahead for completion in Fall 2003 per the original schedule.

G7 Celilo Modernization
Work is proceeding on this project with the expected energization revised from Fall 2003 to Summer 2004.

G8 Monroe – Echo Lake 500 kV Line
Non-transmission solutions are being reviewed by BPA as possible alternatives for this project scheduled for Fall 2005.

G9 Bell – Coulee 500 kV Line
This project, which is intended to increase capacity across the West of Hatwai bottleneck, is on schedule for Fall 2004 energization as reported in last year's report. Since that time,

agreement has been reached on additional Phase 1 facilities (many of which were included on the list of potential Phase 2 projects in the 2001 Infrastructure Technical Review Committee Report), which are presently planned for energization between 2003 and 2007. These facilities and modifications, which will be constructed/implemented by the Avista Corporation, include the following:

- Benewah-Shawnee 230 kV Line.
- Dry Creek 230 kV Switching Station.
- Beacon-Rathdrum Double Circuit 230 kV Line.
- Increase operating limits on Hatwai-Lolo 230 kV Line.
- Increase operating limits on Hatwai-North Lewiston 230 kV Line.
- Increase operating limits on Dry Creek-North Lewiston 230 kV Line.
- Install 230 kV shunt capacitors at Benewah (200 MVAR).
- Install 230 kV shunt capacitors at Dry Creek (200 MVAR).

All of the facilities listed above will be taken through the WECC Regional Planning Process. Since the Bell-Coulee 500 kV line has already been through the process, it is expected that this will be an abbreviated process with comments only for the additional facilities. Any additions or changes to the above list of projects will be identified through the Regional Planning Process. The complete slate of Phase I facilities reinforcing the West of Hatwai Path including the Coulee – Bell 500 kV line will then be taken through the WECC Path Rating Process. Additional (West of Hatwai Phase II) facilities, which may be necessary in the Northern Idaho / Western Montana area will be identified in a follow up effort.

1.6 Glossary of Acronyms and Terms

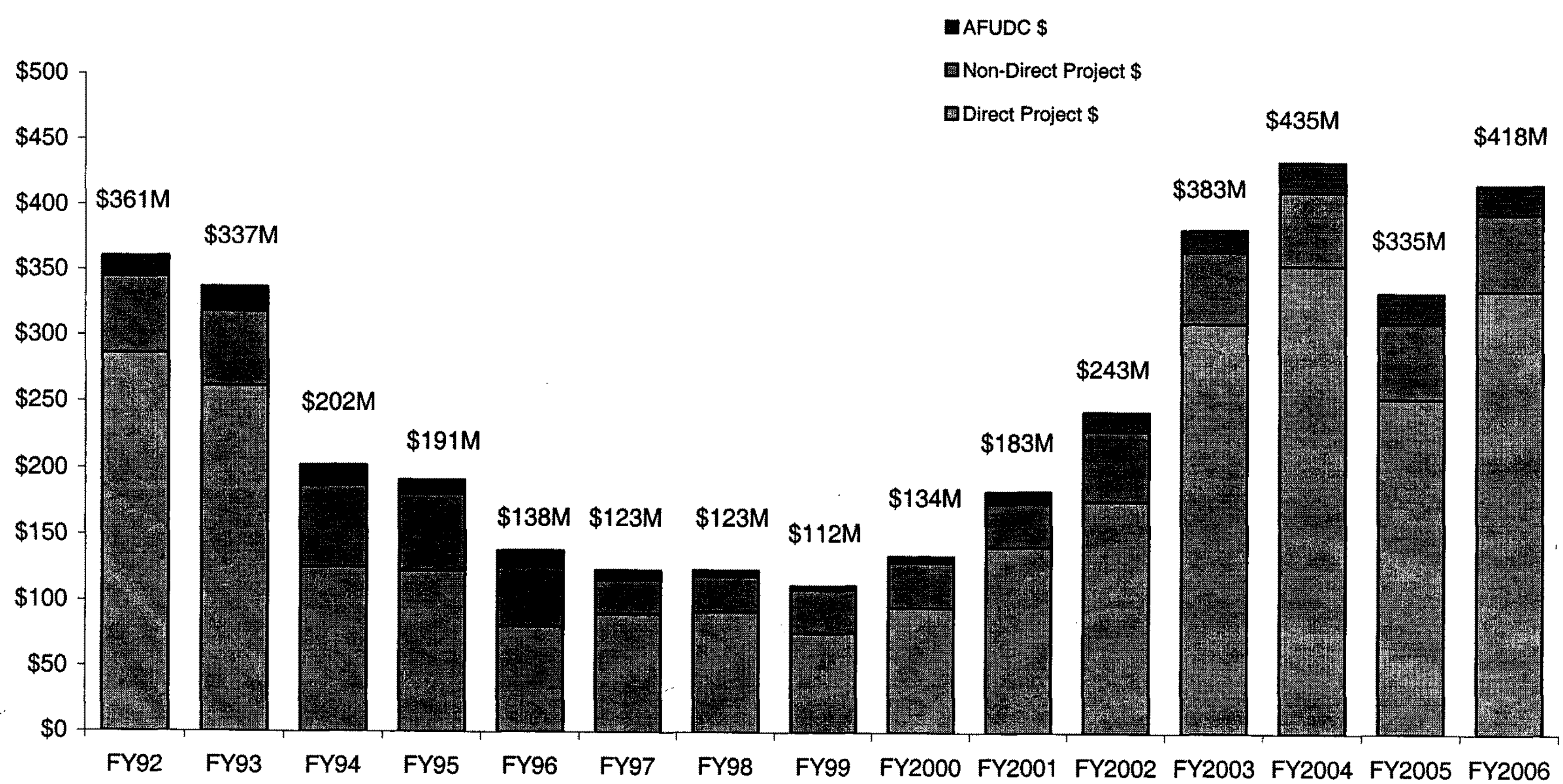
BiOp	Biological Opinion
MW	A unit of power. One MW would serve approximately 700 homes.
NRTA	Northwest Regional Transmission Association
NWPP	Northwest Power Pool
RTO	Regional Transmission Organization
WECC	Western Electricity Coordinating Council

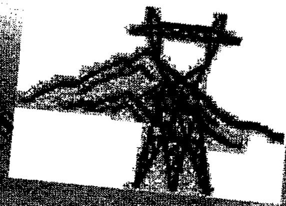
Bulk Transmission – Transmission lines that serve as the backbone of the grid, typically operated at voltages of 230-kV and above.

1.7 References

[1] "NERC/WECC Planning Standards, Board of Trustees approved April 18, 2002.
[2] "Annual BPA Transmission Infrastructure Review," January 15, 2002.

Figure 1. TBL Capital Projects Historical & Future Trend



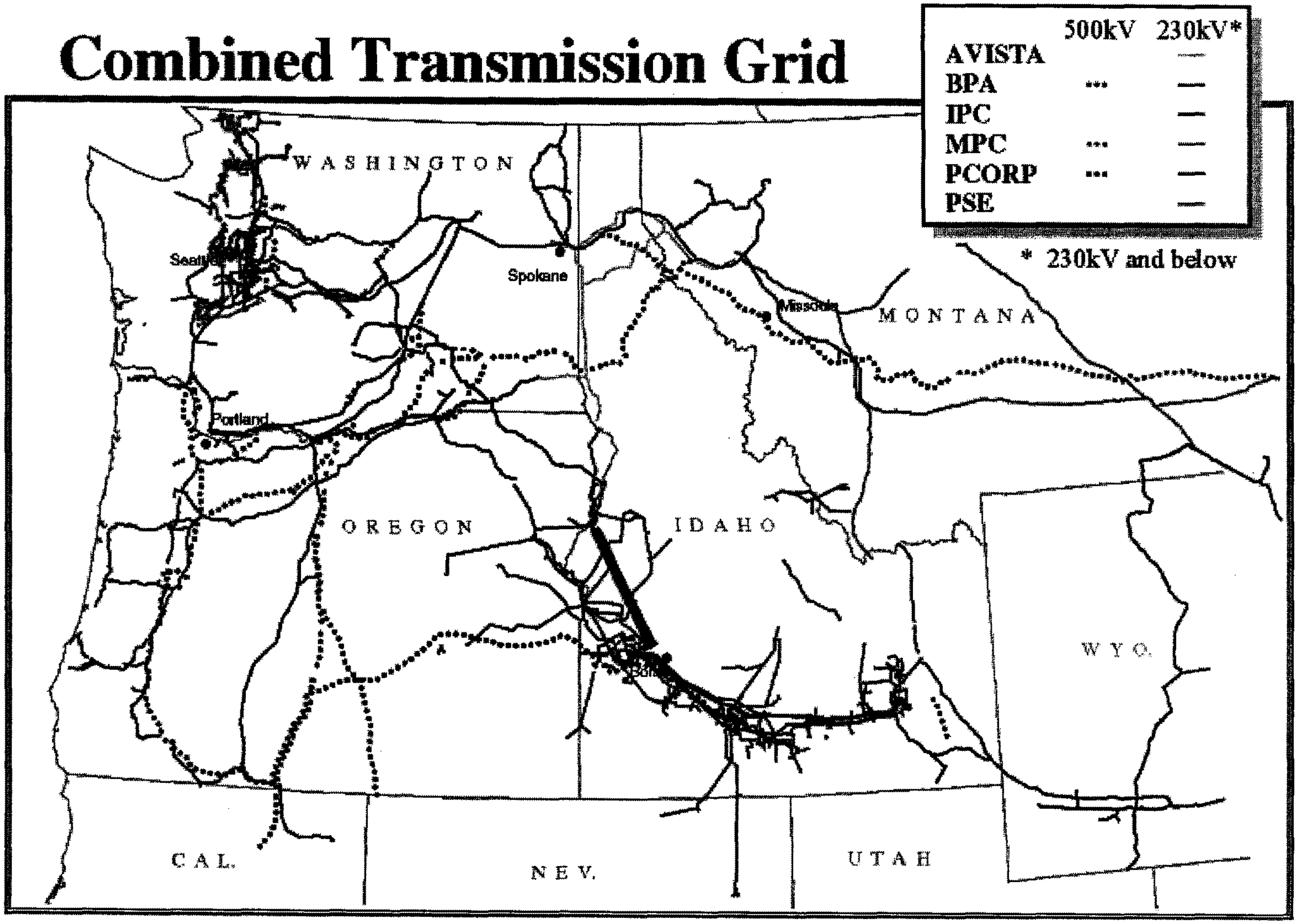


BPA Transmission System

- BPA operates 80% of the high-voltage grid in its service area (OR, WA, ID and western MT).
  - More than 15,000 miles of line
  - Two fully redundant control centers
  - Over $5 billion federal investment
  - About $720 million in annual revenues ($550 M for wires)
- About 50% of the grid looking at the U.S. portion of the NW Power Pool (add rest of MT, UT, WY, part of NV).
- BPA voluntarily complies with FERC open access rules.

Bonneville Power Administration

Combined Transmission Grid

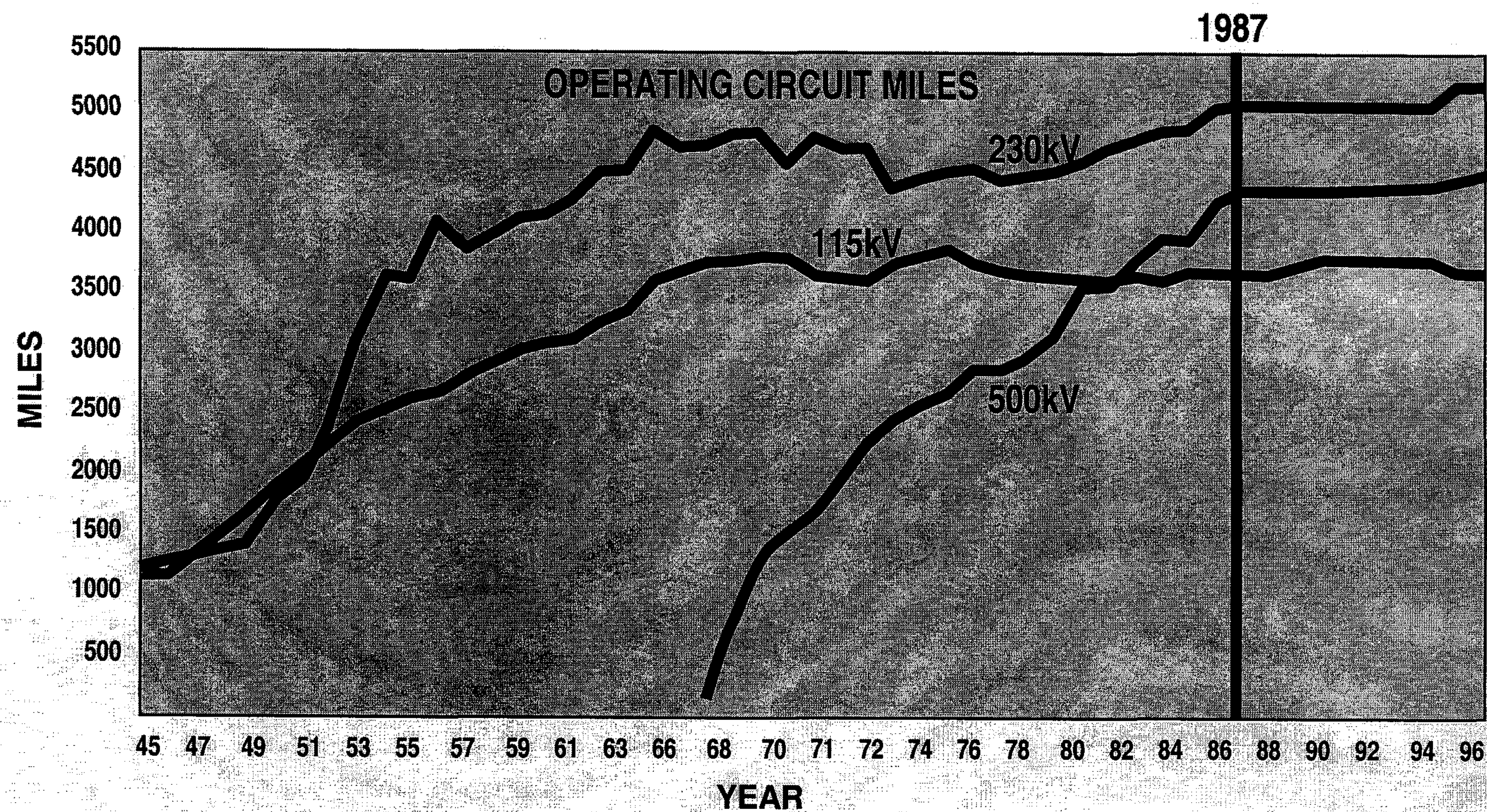


Where are we?

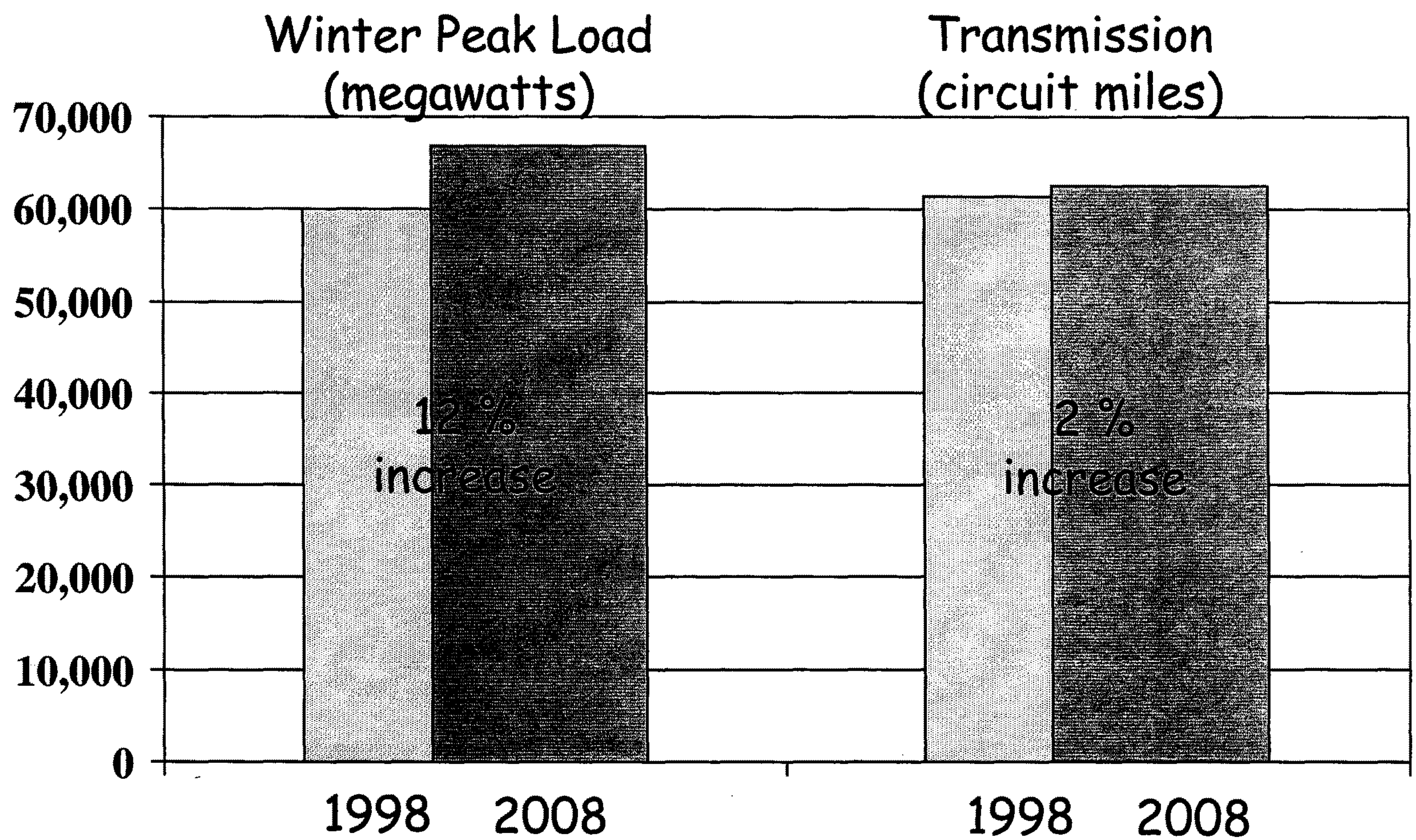
- **Current Situation**
  - Loads growing steadily at 1.8% per year
  - Little new transmission since 1987
- **Objectives of BPA Infrastructure Plan**
  - Keep the lights on — reinforce the system to comply with national reliability standards
  - Interconnect needed new generation
  - Remove constraints that limit economic trade & our ability to maintain the system

Bonneville Power Adminis

Transmission Line Construction

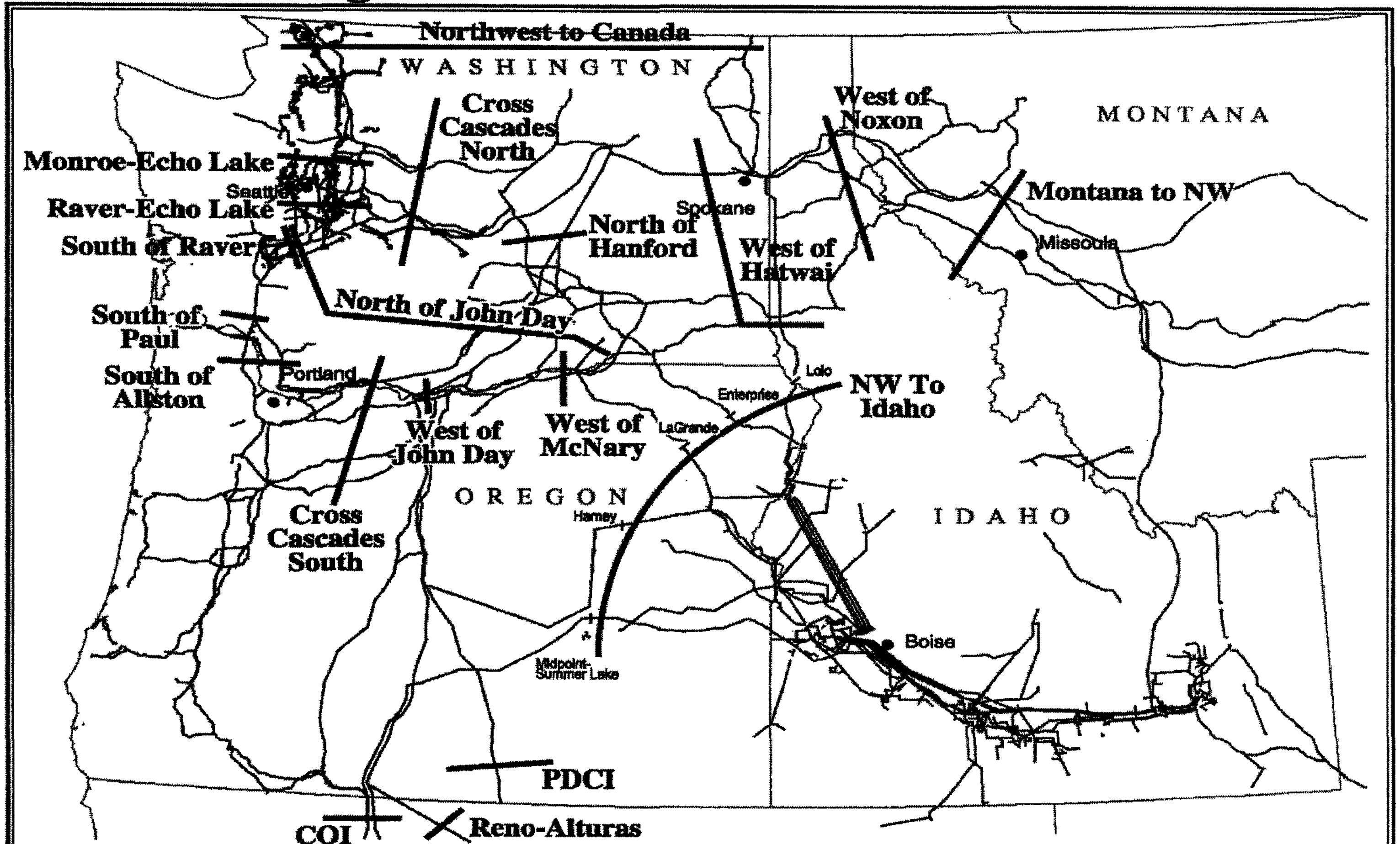


Transmission Needs



Bonneville Power Administration

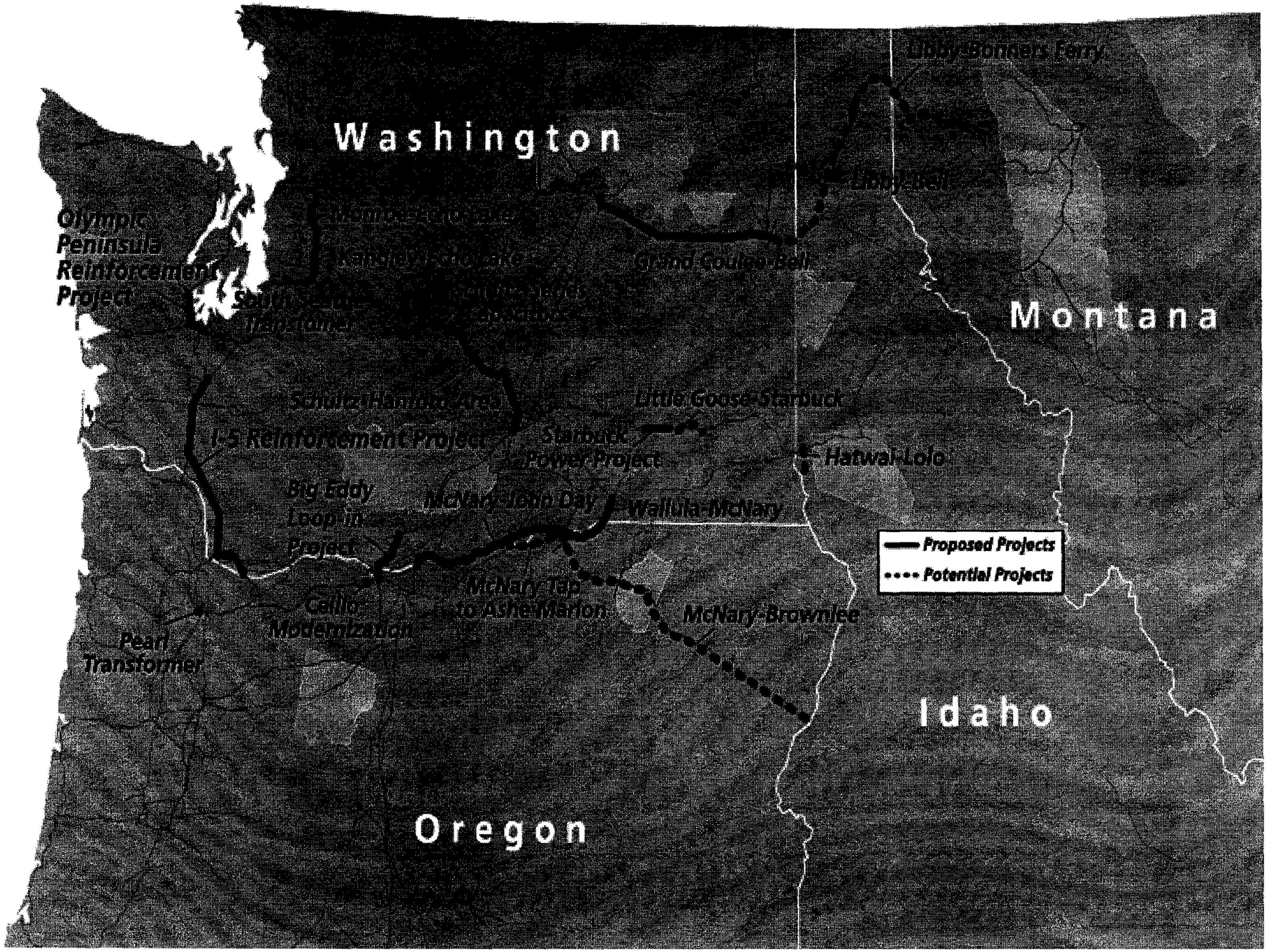
Figure 1: NW Constrained Paths



Solution

The proposed projects:

- **Reinforce the load centers**
- **Integrate needed generation**
  - Depending on which plants are built -
  - Can integrate between 8000 to 12000 MW
- **Relieve crippling congestion**
  - Focus on NW constrained paths
  - Reduces price volatility
- **Put some reliability margin back into the grid**
  - Reduce vulnerability to cascading electrical outages
  - Allow outages for maintenance


Washington
Montana
Idaho
Oregon
Libby-Bonners Ferry
Libby-Bell
Grand Coulee-Bell
Olympic
Peninsula
Reinforcement
Project
Schultz/Hanford Area
I-5 Reinforcement Project
Little Goose-Starbuck
Starbuck
Power Project
Hatwai-Lolo
Big Eddy
Loop-in
Project
McNary-John Day
Wallula-McNary
McNary Tap
to Ashe-Marion
McNary-Brownlee
Celilo
Modernization
Pearl
Transformer
Proposed Projects
Potential Projects

Bonneville Power Administration

Funding Certainty

- We can't start construction projects that we're not sure we can finish.
- This requires additional borrowing authority.
  - BPA sought $2 billion to meet long-term needs.
  - The President's budget now includes $700 million.
  - BPA borrowing is repaid by BPA ratepayers.
- BPA will will encourage non-federal and joint financing of significant transmission line expansions.
- FERC policy today requires developer funing of Network upgrades as a credit against wheeling payments.

From:	Mittelstadt, Bill - TOM-PPO2-2
Sent:	Monday, June 24, 2002 8:56 AM
To:	'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; 'Groce, Ed'; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; 'Kinney, Scott'; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO-DITT2; 'Waples, Scott'
Cc:	Mittelstadt, Bill - TOM-PPO2-2; Haner, John - TOM-PPO2-2
Subject:	ITRG Draft Report

Dear Technical Review Committee Participants

This year we conducted the second annual review of BPA's proposed transmission infrastructure projects. BPA offered four projects for consideration. Based on your feedback, BPA recommends that two of the projects be advanced: G10 (Portland Area Additions) for construction and G12 (Olympic Peninsula Reinforcement) for environmental review. The other two projects will be brought forward again.

Attached please find a draft report based on the format from last year. It summarizes BPA's proposals and our sense of the Committee views. We have tried to provide the additional information you requested and incorporate your feedback. Please feel free to edit the documents and return them to me. Depending on the response we can finalize the documents based on your edits, set up a conference call if further discussion is warranted, or set up a another meeting in Portland if that's what you want to do.

Our intention is to repeat the process with additional proposals next year.

I appreciate the time you have taken to provide critical feedback and I look forward to hearing from you.

Regards
Bill

William A Mittelstadt (E-mail)... Cover Letter.doc Report Draft.doc Appendix A.doc Appendix B.doc Appendix C.doc Appendix D.doc

Appendix E.doc

June 21, 2002

Addressees

Subject: Infrastructure Technical Review Committee Report

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002).

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority as well as full consideration of third party financing options. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

To ensure that BPA's proposal designs and prioritizes improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers, a technical and economic review committee was formed (Technical Review Committee). The committee drew on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC) and the Operating Committee (OC). The committee provided its first report on August 30, 2001 with the recommendation that BPA install necessary system facilities as soon as possible. A critical first step is securing additional borrowing authority for BPA.

Attached is the second annual report on the transmission infrastructure proposal that contains the conclusions and recommendations of the review committee. The report recommends two additional projects for implementation. The report also asks BPA to present any additional proposed major projects for consideration next year.

Ken Morris PacifiCorp	John Martinsen Snohomish PUD	Wayman Robinett Puget Sound Energy
Hardev Juj Seattle City Light	Scott Waples AvistaCorp	Ronald Schellberg Idaho Power Company
John Leland Montana Power Company	Jim Eden PGE Company	

cc
Infrastructure Technical Review Committee

Upgrading the Capacity and Reliability of the BPA Transmission System

Report of the Infrastructure Technical Review Committee

June 22, 2002

Table of Contents

Appendices

Please refer to the August 30, 2001 Infrastructure Review Committee report for information on the purpose of this Committee, terms of engagement and general system need. Also please refer to this report for system maps.

1. Executive Summary

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002). Problems with the transmission in the region are manifested in several ways:

- Chronic congestion existing on a number of transmission paths requires curtailment of both firm power deliveries and economy energy.
- Resolution of the Western energy crisis requires development of new generating resources. The vast majority of proposed Northwest resources cannot obtain firm transmission service, or be integrated, without additional bulk transmission.
- While power loads have been growing steadily at 1.8% annually and the use of the transmission system is up by over 2% annually, few bulk grid transmission lines were added in the past 15 years.
- It will take much longer to site and build transmission to deliver needed new generation than it will take to build and site the generation. New transmission is needed to meet existing and future obligations in order to comply with recently adopted national and regional standards that ensure a reliable power system.
- It is extremely difficult to meet obligations when facilities are removed from service to conduct normal maintenance or to construct new facilities.

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

To ensure that BPA's proposal designs and prioritizes improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers, a technical and economic review committee was formed (Technical Review Committee). The committee drew on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC), Operating Committee (OC) and the Northwest Regional Transmission Association ("NRTA") Planning Committee ("PC"). The committee was asked to report its initial recommendations by August 30, 2001 to enable BPA to install necessary system facilities as soon as possible.

This review is the second in an annual process to coincide with BPA's annual budget cycle. It covers two projects of BPA's infrastructure proposal. Review of additional projects will be conducted in subsequent years. There are several additional parallel efforts that provide for review of proposed transmission additions. This committee's analysis and recommendations will be shared and further analyzed in the following forums.

- Northwest Power Pool (NWPP) Transmission Planning Committee
- Western Electricity Coordinating Council (WECC) Regional Planning Group
- National Environmental Policy Act (NEPA) review for individual projects

During the first part of 2002 the committee met twice to review additional infrastructure proposal developed by BPA. While some of the proposals have been under development in previous forums with outside participation, other proposals were presented for the first time. The committee has reached the following conclusions and recommendations based on its review:

- There continues to be a compelling and immediate need to upgrade portions of the Northwest bulk transmission grid. Solutions proposed by BPA in coordination with others address the identified problems.
- Projects evaluated in the first review should continue on the revised timetable proposed by BPA. BPA should continue to reevaluate project need and timelines, particularly for projects driven by generation integration.
- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G12 (Olympic Peninsula Reinforcement) is also important, although the need date is later than initially estimated based on the most recent load forecasts. Opportunities for non-transmission alternatives should be pursued in parallel with the proposed transmission fix.
- Projects G13 (Paul – Troutdale 500-kV Line) and G14 (Hanford-Ostrander 500 kV loop-in) were examined on a preliminary basis. Project G13 is critical to integration of new generation in the I-5 corridor. BPA should complete details of the plan of service over the next 60 days and bring this through the WECC Regional Planning Process. In addition, coordination with PGE is required. The benefits of project G14 are not clear given proposed I5 generation development and potential higher costs to route around the Columbia Gorge Scenic Area. BPA should bring these projects forward to the Committee for consideration in 2003 after further examination of alternatives and need.
- The need still remains to increase BPA borrowing authority for *transmission* by at least $1 billion in order to ensure that sufficient financial resources are available to accomplish transmission expansion over a ten-year planning horizon.
- BPA should continue to pursue and evaluate third party financing opportunities for major new transmission projects.
- Preliminary analysis has shown that increased transmission use will recover the cost of the proposed capital additions. Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure 10 to 20 year firm transmission service contracts before proceeding with construction. (Note: BPA's transmission investments are repaid by its transmission customers, not taxpayers.)

- Additional reinforcements by BPA and others are needed to maximize reliability and transfer capability from the proposals. Other Northwest utilities have planned transmission additions, and maximum benefits will be achieved through coordinated development.
- Future reviews should be conducted annually to ensure that BPA designs and prioritizes major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers.

3. Projects for 2002 Review

Project List

Project		Cost (loaded) ($M)	Energization Date	Capacity Added MW
Portland Area Additions	G10	9	2003	300
Olympic Peninsula Reinforcement	G12	26	2005	430
Total		35		

Project Drivers

	Load Service	Entitlement Return	Generation Integration	Transfers	Reliability	O&M Savings	BiOp
G10	x				x		
G12	x				x		x

3. Glossary of Acronyms and Terms

MW	A unit of power. One MW would serve approximately 700 homes.
NRTA	Northwest Regional Transmission Association
NWPP	Northwest Power Pool
RTO	Regional Transmission Organization
WECC	Western Electricity Coordinating Council

Bulk Transmission – Transmission lines that serve as the backbone of the grid, typically operated at voltages of 230-kV and above.

Appendix A – Participants

Infrastructure Technical Review Committee Participants

Name		With	Phone	E-Mail	Note
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Appendix B –Project Schedules

Project		Energization
Kangley - Echo Lake 500 kV line	G1	Fall 2003*
Schultz - Black Rock 500 kV line	G2	Fall 2004
McNary - John Day 500 kV line	G3	Fall 2004
Lo Monumental - Starbuck 500 kV line	G4	Fall 2004**
Smiths Harbor - McNary 500 kV line	G5	Fall 2004**
Schultz series capacitors	G6	Fall 2003
Celilo Modernization	G7	Summer 2004*
Monroe - Echo Lake 500 kV line	G8	Fall 2005
Bell - Coulee 500 kV line	G9	Fall 2004
Pearl Transformer	G10	Fall 2003
South Seattle Transformer	G11	Fall 2004**
Olympic Pennsula Reinforcement	G12	Fall 2006*,**
Paul - Troutdale 500 kV line	G13	Fall 2005
Hanford - Ostrander loop-in	G14	Spring 2005**

*Denotes change from September, 2001 report
**Energization may change depending on need

Appendix C – Project Summaries

G10. Portland Area Additions (Pearl 500/230 kV Transformer)

Background

The Portland area is currently served by four 500/230 kV transformers, Troutdale on the east side, McLoughlin in SE Portland, Pearl in SW Portland and Keeler on the west side. This project is another phase of reinforcing the load serving capability from the bulk transmission system into the greater Portland area. Earlier reinforcements included adding a new 230 kV double circuit line between Pearl and PGE's Sherwood substation.

Addition of the 2nd transformer at Pearl will require extension of both the 500 kV and the 230 kV buses. These extensions are within the existing Pearl substation.

Limiting Outages Addressed
Existing Pearl 500/230 kV Transformer

Benefit – Load Area Service
This project will increase the load carrying capability into the greater Portland area. Without this project it would be necessary to trip off load in the Portland area to relieve overloads during abnormal cold winter peaks for an outage of the existing Pearl transformer.

Business Case

This project provides the capacity to carry additional load in the Portland area at the rate of 75 MW per year from 2004 though 2007. Beyond that date it will provide load serving benefit to the capacity of the bank following a suitable plan to address the Big Eddy – Ostrander 500 kV line outage. For the purpose of this analysis the benefit stream is limited to 300 MW for the period beyond 2007. In the Table below, Alternative 1 is the preferred plan. Alternatives 2 and 3 are described on the next page.

Alternative	Revenue($M)	Costs($M)	Net PV	B/C	Repayment Years	In Service	Life
1	30.8	11.2	19.6	2.75	6	2003	2037
2	30.8	32.6	(1.8)	0.95	14	2003	2037
3	30.8	54.4	(23.7)	0.57	25	2003	2037
1 (0.9%)	26.9	11.9	15.0	2.26	8	2003	2037

Risk

The risk of cost recovery of this project is related to the Portland area load growth rate. Halving the 1.8% assumed growth rate extends the cost recovery period to from 6 years to 8 years. This constitutes a very low risk.

Project Description
This project adds a 2nd 500/230 kV transformer at the existing Pearl Substation. The new transformer will be 3 single phase units (433 MVA each). The new bank will be equipped with a 9 step LTC and a tertiary for station service. One 500 kV breaker and one 230 kV breaker will be added. The 500 kV and 230 kV buses will be extended.

Alternatives Considered

- Install a 500/230 kV transformer at PGE's Sherwood Substation. This location would be higher cost, require additional property and would be difficult to site. It was considered in the past, but the decision was made to increase the 230 kV capacity between Pearl and Sherwood.
- Install a 500/230 kV transformer at McLaughlin Substation.
- Curtail load in the event of a transformer outage (no build).
- Demand side management.

No-Build Alternative
The "no build" alternative represents the risk of load interruption for a first contingency 500/230 transformer outage at any of the four following locations: Keeler; Pearl; McLaughlin; Troutdale. Load interrupted ranges from 75 MW in 2004 to 900 MW in 2015. Based on a single phase transformer outage failure rate of once/100 years the expected composite failure rate is:

MTBF = (100 years/transformer)/(4 banks*3 transformers/bank)
MTBF = 8 years

Non-Transmission Alternatives
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and Environmental Economics, Nov. 2001 (available at <http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm>). BPA concluded that these measure could not be implemented in time and in sufficient magnitude to adequately address the problem. BPA will fully consider these measures for future needs.

Decision
BPA chose the preferred plan because it has the lowest initial cost and minimal environmental impacts. It is a robust choice under lower load growth and presents minimal business risk.

Energization Date: **Fall 2003 (Preferred Alternative)**
Estimated Cost: **$9M**

G12. Olympic Peninsula Reinforcement (Paul-Shelton 500-kV line)

Background

The Olympic Peninsula area load is served from Olympia substation via 230-kV and 115-kV transmission. The major source to Olympia to serve these loads is the 500-kV transmission line from Paul substation. An outage of this 500-kV source to Olympia would result in a voltage collapse during extra heavy winter load conditions. The Olympic Peninsula transmission system has been pushed to its limit with the use of shunt capacitors. A total of approximately 20 capacitor groups amounting to approximately 900 MVAR are already installed. A second 500-kV source is needed to solve the problem as early as 2003. However, yet another shunt capacitor group is being added in 2003 to delay the need for this project until 2005. In addition, a double-line outage of the 230-kV double-circuit line from Olympia to Shelton would result in a total loss of the Olympic Peninsula during normal winter load. The proposed reinforcement will solve both of these problems and reinforce the Olympic Peninsula region.

Limiting Outages Addressed

- Olympia 500/230-kV transformer
- Paul-Olympia 500-kV line
- Olympia-Shelton 230-kV double line
- Olympia 230-kV breaker failure

Benefit - Load Area Service

This project will prevent these outages from impacting service to the Olympic Peninsula by providing a second source of power to the Peninsula from Paul Substation. This project will also increase the load service capability to the Olympic Peninsula under non-outage conditions as well as mitigate or delay other system upgrades that would be needed in the future if this project were not built.

Business Case

This project provides the capacity to carry additional projected normal winter load in the Olympic Peninsula area in compliance with NERC/WECC Planning Standards for Category A-C outages. For the purpose of this analysis revenues are based on 1.8% load growth at 26 MW/year capping at 338 MW in 2019. In the Table below, Alternative 1 is the proposed plan and Alternative 2 is moving the 500/230-kV transformer to Olympia (see below).

Alternative	Revenue($M)	Costs($M)	Net PV	B/C	Repayment Years	In Service	Life
1	21.6	29.3	(7.8)	0.74	20	2006	2040
2	21.6	27.2	(5.7)	0.79	19	2006	2040
1 (0.9%)	14.4	34.1	(19.7)	0.42	31	2006	2040

Risk
Repayment of this project is based on load growth in the Olympic Peninsula area. The benefit to cost ratio (B/C) of Alternative 1 is less than one for a 9% discount rate but would equal one for a discount adjusted to 6.65% indicating a comparable return on investment of 6.65% over the 34 year life of this project. With the BPA financing rate of 6.75%, an inflation rate of 2.64% and the expected load growth rate of 1.8% the repayment period is estimated to be 20 years. For a reduced growth rate of 0.9% the repayment period is estimated to be 31 years.

Project Description
- Build approximately 13.8 miles of 500-kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to the Shelton 500 kV yard. The line will be routed on the existing Olympia-Shelton right of way. Cut the Paul-Satsop 500 kV line at corridor intersection and connect the Paul end to new 500 kV line to Shelton.
- Remove Olympia-Shelton 115 kV line #1 from Olympia to Dayton Tap.
- Construct a 500 kV yard approximately 1 mile south of the existing Shelton substation, move Satsop 500/230 kV transformer to this location and tie it to Shelton 230 kV bus via 1 mile long 230 kV line.
- Build approximately 6 miles of new 230 kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to Olympia substation. Connect this new line to Satsop end of cut Paul-Satsop 500 kV line.

Alternatives Considered
- Move Satsop 500/230 kV transformer to Olympia substation and terminate the Paul-Satsop 500 kV line at Olympia.
- 400-600 MW of load tripping for the Olympia – Shelton 230 kV double circuit line outage.
- No build alternative

No-Build Alternative

(a) The following information applies to loss of load for N-1 contingencies if the transmission system is not reinforced:

- 2 year MTBF for N-1 Paul-Olympia 500 kV line with average and maximum outage durations of 1.25 hours and 6.7 hours respectively
- 100 year MTBF for the Olympia 500/230 transformer and 2 week replacement time.
- required load curtailment for either outage increases by 26 MW yearly starting in 2010.

The probability of loss of load increases year by year related to the amount of time in the year the load is above the design limit. For example, assuming a figure of 5% the probability of loss of load for the line would be (1/2 + 1/100)(0.05) = 0.025 for a net MTBF of about 40 years between events.

(b) The following information was used to estimate the probability of loss of load for N-2 contingencies if the transmission system is not reinforced:

- 9.3 year MTBF for N-2 outage of Olympia – Shelton 230 kV lines 3 and 4
- 0.018 breaker failures/year for any of eight breakers at Olympia
- load distributions from the past five years

Based on this we can expect to lose the entire Olympic Peninsula load (forecasted at 1170 MW for normal winter peak and 600 MW for summer peak in 2003-2004) about every 8 years in the winter. Risk of loss of load in the summer is very low. These impacts would be expected to be larger as load grows in the area. Based on the current system, for the double circuit outage we can supply 615 MW in the winter and 490 MW in the summer. Not considered in this analysis was the 500/230 kV transformer outage rate of once per 100 years.

Non-Transmission Alternatives
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and Environmental Economics, Nov. 2001 (available at <http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm>). These measures could cost-effectively defer the need under N-1 contingencies, although they can not address the N-2 problems. BPA will further consider non-transmission alternatives before proceeding with this project.

Decision
BPA chose the preferred transmission plan because it outperforms the Olympia option for both N-2 critical outages for essentially the same present worth cost without O&M expenses included. O&M costs would be higher for the Olympia option based on the amount of extra equipment that would be needed at the Olympia substation. The Olympia option would require major 230 kV work at the Olympia substation, including expansion of the 230 kV yard. Land would also have to be purchased around the 500 kV yard for 230 kV line routing into the 230 kV bus. Some of the line routing into the 230 kV bus may not even be physically possible based on current line routing, tower and road locations, land needs and right-of-way widths. The Shelton option has 8 MW less losses than the Olympia option based on 1170 MW of load, which is equivalent to normal winter load in 2002-03. These losses will increase with increases in load. The Shelton option would leave the system better prepared for the future. It is a robust choice under lower load growth and presents minimal business risk. BPA will further consider non-transmission alternatives before proceeding with this project.

Energization Date: Fall 2006
Estimated Cost: $23-26 M

G13. Paul – Troutdale 500-kV Line

Background
The existing I-5 corridor transmission system is limited to:
- 2400 MW North of Allston by a double Paul – Allston 500-kV line outage
- 1650 MW South of Allston by the Allston – Keeler 500-kV line outage

With new generation projects proposed in the area, the existing system is not adequate to provide transmission service to most new generating projects on a firm basis, likely resulting in generation curtailments.

At present, the double Paul – Allston 500-kV line outage requires 2850 MW generation dropping and opening of both Chehalis – Longview 230-kV line that run in parallel to the Paul – Allston line. This sectionalizing removes the northern feed into Portland metro area, resulting in load service only from the east side through Ostrander. Sectionalizing greatly reduces reactive margins in the system, which will become a limiting factor as load grows in Portland area. Sectionalizing was also shown to degrade transient stability performance.

Currently, the Allston – Keeler 500-kV line outage requires generation dropping up to 2850 MW to prevent thermal overloads. Historic data indicates that there were 19 line outages in the past 16 years, mostly cased either by lightning hits or trees. It is very desirable to reduce generation dropping amount for a single contingency because ….

This project is being taken through the WECC Regional Planning process.

Limiting Outages Addressed
Paul – Allston 500-kV double line
Allston – Keeler 500-kV line
Keeler – Pearl 500-kV line
Keeler breaker failure

Benefits

Table 1. Generation projects proposed in the area affecting transmission needs:

Project	Capacity	Energization	North of Allston	South of Allston
Napavine	600	11/1/03	More stress	More stress
Grays Harbor I	630	6/1/03	More stress	More stress
Longview – Enron	300	7/1/03	Less stress	More stress
Mint Farm	280	5/1/03	Less stress	More stress
Summit	530	11/1/03	Less stress	More stress
Big Hanaford	250	1/1/02	More stress	More stress
Port Westward	650	12/31/03	Less stress	More stress
Centralia efficiency	+ 70	Done	More stress	More stress
Grays Harbor II	630	11/1/04	More stress	More stress
Port Vancouver	700	6/1/05	Less stress	Less stress

It is evident that new generation will greatly increase stress the constrained I-5 paths. The existing system is not adequate to provide transmission service to most generating projects on firm basis, very likely resulting in generation curtailments. The new 500-kV line is expected to provide firm transmission rights for the proposed projects in the area.

A. Transfer Increase

It is expected that South of Allston limit will increase from 1650 MW to 2,700 – 2,900 MW. The new line will eliminate or greatly reduce the need for generation dropping for N-1 outages. The time to thermal overload will allow to ramp down generation of dropping. Upgrades of parallel 115-kV and 230-kV lines may be required to get the full capacity.

B. Load Service in Winter Conditions

Studies are under way.

Business Case
This project is driven by requests for long-term firm transmission by new generation and imports. Parties requesting transmission would be expected to fund the upgrade consistent with FERC policy.

Risk
The risk associated with this project is small because the generators will be expected to finance the transmission investment and/or commit to long-term transmission service.

Project Description
At present time, the plan of service is not fully defined. Two conceptual options have been considered and studied for electrical performance. Alternative #1 includes a 500-kV line from near Longview to Troutdale, and alternative #2 is a 500-kV line from near Longview to Pearl.

Decision
No preferred alternative is proposed at this time. The project will be returned to the Technical Review Committee for consideration in 2003 following the WECC Regional Planning Process.

Energization Date: **Fall 2005**
Estimated Cost: **$117-155 M**

G14. North of John Day/Portland Area Reinforcement – (Loop the Hanford-Ostrander 500-kV line into Big Eddy)

Background

The proposed new generation additions around the McNary area along with the new McNary-John Day 500-kV line will increase the stress across the North of John Day and the flow between John Day and Big Eddy. This project will relieve some of the North of John Day constraint and reinforce the transmission between John Day and Big Eddy. In addition, this project will also reinforce the bulk load serving capability into the greater Portland area. During abnormal cold weather, an outage of the Bid Eddy-Ostrander 500-kV line results in voltage collapse in the Portland area. This Project will in effect create a second Big Eddy – Ostrander 500-kV line and increase the load serving capability to the Portland area.

Limiting Outages Addressed

Ashe-Marion/Slatt-Buckley 500-kV double line loss (summer)
John Day-Big Eddy 500-kV double line loss (summer)
Slatt 500-kV breaker failures (summer)
Big Eddy-Ostrander 500-kV line (winter)
Pearl 500-kV breaker failures (winter)

Benefit – Congestion Relief and Load Area Support

This project will increase the North of John Day capability by approximately 250-300 MW and increase the capability between John Day and Big Eddy by approximately 600-700 MW. This project also reinforces the bulk grid to serve greater Portland area load and eliminate the need for building second Big Eddy-Ostrander 500-kV line.

Business Case

The primary drivers of this project is North to South network transfers and provide additional network capacity for service to the Portland area load. The estimated cost recovery of this project at current rates and for the alternatives considered is over 35 years. In view of the long payback period lower cost alternatives or deferral will be considered.

Risk

The benefit ascribed to this project for the Portland area load is related to the timing of the Paul – Troutdale project which in part serves this need. The portion of benefits ascribed to intertie support will be beneficial at the time the project goes into service but is not sufficient alone to ensure full cost recovery. Risk that costs will not be recovered for this project as proposed at this point is high.

Project Description

- This project consists of constructing approximately 16.5 miles of 500-kV double circuit line to the Columbia River crossing and approximately 18 miles of single circuit 500-kV line to Big Eddy and 2 miles of line to John Day.

- Develop a new 500-kV switching station next to the existing Hanford (Wautoma) – Ostrander 500-kV line and loop in the Hanford-Ostrander line into the new switching station.
- Add terminals at Big Eddy and John Day to terminate the new lines.

Preliminary Alternatives

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit.

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit and build a third 20miles of single circuit 500-kV line between John Day and Big Eddy

Decision
No preferred alternative is proposed at this time. The project may be returned to the Techncial Review Committee for consideration in 2003 following further analysis.

Energization Date: **Spring 2006**
Estimated Cost: **$70-90M**

Appendix D - Economic Analysis

The analysis used for projects G10 and G12 was conducted using Excel spreadsheet calculations. The following indicators of economic performance were computed:

- Repayment time (years from in service date)
- Net Present Value
- Benefit to Cost Ratio

The basic economic assumptions used were as follows:

Discount Rate		9.00%
Inflation Rate		2.64%
BPA Financing Rate		6.75%
O&M Escalation		0.00%
BPA Rate Escalation		0.00%
O&M Actual		2.64%
BPA Rate Actual		2.64%

The high discount rate of 9% favors projects with a faster payback period. A lower discount rate would increase benefit/cost ratio for projects G10 and G12. The treasury borrowing rate of 6.75% represents recent historical BPA borrowing.

Net Present Value and Benefit to Cost were computed using a substation equipment service life of 34 years[1] since both projects G10 and G12 have major substation components.

Capital cost expenditures were distributed over the expected year of obligation over the construction period.

BPA transmission revenues were reckoned at the rate of $1.013 $/kW-mo (12.156 $/kW-year).

Projects G10 and G12 assume that 75% of the load increase is transmission revenue producing. Assuming 50% revenue producing reduces the benefit to cost ratios by about 1/3.

Typical operations and maintenance costs are used[1]

[1] Annual Financial Requirements for Bonneville Power Administration Transmission System and revised Operation and Maintenance Tables, Larry Davidson, March 31, 2000.

Appendix E –Supplemental Cost Estimates

G-10 Preferred Plan (cost estimate)

Add a 500/230 kV transformer at BPA's Pearl Substation.
(work order quality estimate)

Requirements:

Add a 500 kV transformer	$
Expand 230 kV yard, 1-230 kV breaker	$
Expand 500 kV yard, add 1-500 kV breaker	$
Associated relays and controls	$
TOTAL	**$8.2m**

G-10 Alternatives (cost estimates)

The following alternatives to the Pearl 500/230 kV transformer were considered.
("back-of-the-envelope" estimates, work required in other PGE's substations)

1. Add the transformer at PGE's Sherwood substation

Requirements:

Acquire property	$2.0m
Add a 500/230 kV Tx	$8.0m
3-500 kv breaker ring bus	$6.0m
1-230 kv breaker	$1.0m
Associated relaying and controls	$2.5m
500 kV line work	$2.0m
Other line relocations	$3.0m
TOTAL	**$24.5m**

2. Add the transformer at McLoughlin substation

Requirements:

Add 11.7 mi of 1272 Narcissus conductor. (on vacant side of tower)	$2.0m
Add 2-230 kV breakers at McLoughlin.	$2.0m
Add a 2nd 500/230 kV transformer at McLoughlin	$8.0m
9 miles of 500 kV line. OST_MCL	$9.0m
4-500 kV breaker ring bus @McLoughlin (may be difficult)	$8.0m
New 500 kV bay at Ostrander	$3.0m
Associated relaying and controls	$2.0m
2-230 kV breakers at Pearl	$2.0m
TOTAL	**$36.0m**

Wright, April E - KFF-2

From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Wednesday, July 17, 2002 12:24 PM
To: 'Groce, Ed'
Cc: 'Waples, Scott'; Silverstein, Brian L - TOP-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2
Subject: RE: ITRG Draft Report

William A Mittelstadt (E-mail)...

Ed

Thanks for your comments. I suggest that we add the phrase "...with appropriate credit provisions" as shown below. Let me know if this is ok or if you have another suggestion.

Thanks

Bill

"Preliminary analysis has shown that increased transmission use will recover the cost of the proposed capital additions. Where the generation project developers are not funding upgrades in advance of construction, BPA should secure 10 to 20 year firm transmission service contracts before proceeding with construction, with appropriate credit provisions. (Note: BPA's transmission investments are repaid by its transmission customers, not taxpayers.)"

-----Original Message-----
From: Groce, Ed [mailto:ed.groce@avistacorp.com]
Sent: Thursday, July 11, 2002 5:05 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'; 'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; Groce, Ed; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; Kinney, Scott; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO; Waples, Scott
Cc: Haner, John - TOM-PPO2-2; Meyers, Lloyd; Schlect, Jeff; Maher, Patrick; Kinney, Scott
Subject: RE: ITRG Draft Report

Bill,

I have reviewed the ITRG report. I would like to comment on the last paragraph on page 4, it reads:

"Preliminary analysis has shown that increased transmission use will recover the cost of the proposed capital additions. Where the generation project developers are not funding upgrades in advance of construction, BPA should secure 10 to 20 year firm transmission service contracts before proceeding with construction. (Note: BPA's transmission investments are repaid by its transmission customers, not taxpayers.)"

Avista feels that BPA should strengthen the financial credit protection relating to requested new construction for generation project developers.

The potential exists for BPA to build a multimillion dollar generation project interconnection and subsequent to that, have the developer declare bankruptcy. Without proper credit or bonding, BPA cannot recover the construction costs. As mentioned, the taxpayers will not pay this bill but the rest of BPA's transmission customers will pay without any benefit. And actually, the taxpayers of the NW will ultimately pay indirectly through higher power rates.

Scott Waples is a signatory to this report, therefore, I would be happy to work with/through him on developing credit language for this report.

Edward F. Groce
Manager Transmission Acquisition
Avista Corporation
1411 E. Mission MSC-7
PO Box 3727
Spokane, WA 99220-3727

509-495-4164 Phone
509-495-4272 Fax
509-981-1914 Cell
ed.groce@avistacorp.com

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Monday, July 01, 2002 12:48 PM
To: Mittelstadt, Bill - TOM-PPO2-2; 'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; 'Groce, Ed'; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; 'Kinney, Scott'; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO; 'Waples, Scott'
Cc: Haner, John - TOM-PPO2-2
Subject: RE: ITRG Draft Report

Hello again,

Please return any comments on this draft material that was submitted to you by July 10 so that the report can be finalized.

Thanks

Bill Mittelstadt

<<William A Mittelstadt (E-mail).vcf>>
> -----Original Message-----
> From: Mittelstadt, Bill - TOM-PPO2-2
> Sent: Monday, June 24, 2002 8:56 AM
> To: Brattebo, Scott; Carr, Geoff; CARTER, LAWRENCE; Eden, Jim; Elizeh,
> Edison; 'Goddard, Richard'; Groce, Ed; HORVATH, JULIUS; Johnson, Don; Juj,
> Hardev; KEENAN, GERALD; Kinney, Scott; KOSTEREV, DMITRY; LANDAUER, MARVIN;
> Leland, John; Lu, Franklin; Martinsen, John; Morris, Ken; Phillips, John;
> QUINATA, JOHN; Reedy, Dana; RODRIGUES, MELVIN; Rust, Jerry; RYDELL,
> KENDALL; Schellberg, Ron; Seabrook, Joe; SILVERSTEIN, BRIAN; STADLER,
> LAWRENCE; VANZANDT, VICKIE; Waples, Scott
> Cc: Mittelstadt, Bill - TOM-PPO2-2; Haner, John - TOM-PPO2-2
> Subject: ITRG Draft Report
>
> Dear Technical Review Committee Participants

>
> This year we conducted the second annual review of BPA's proposed
> transmission infrastructure projects. BPA offered four projects for
> consideration. Based on your feedback, BPA recommends that two of the
> projects be advanced: G10 (Portland Area Additions) for construction and
> G12 (Olympic Peninsula Reinforcement) for environmental review. The
> other two projects will be brought forward again.
>
> Attached please find a draft report based on the format from last year.
> It summarizes BPA's proposals and our sense of the Committee views. We
> have tried to provide the additional information you requested and
> incorporate your feedback. Please feel free to edit the documents and
> return them to me. Depending on the response we can finalize the
> documents based on your edits, set up a conference call if further
> discussion is warranted, or set up a another meeting in Portland if that's
> what you want to do.
>
> Our intention is to repeat the process with additional proposals next
> year.
>
> I appreciate the time you have taken to provide critical feedback and I
> look forward to hearing from you.
>
>
> Regards
> Bill
>
>
>
> << File: William A Mittelstadt (E-mail).vcf >> << File: Cover Letter.doc
> >> << File: Report Draft.doc >> << File: Appendix A.doc >> << File:
> Appendix B.doc >> << File: Appendix C.doc >> << File: Appendix D.doc >>
> << File: Appendix E.doc >>

Wright, April E - KFF-2

From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Friday, July 19, 2002 4:35 PM
To: 'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; 'Groce, Ed'; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; 'Kinney, Scott'; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO-DITT2; 'Waples, Scott'
Cc: Haner, John - TOM-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2; Maher, Mark W - T-DITT2; Whitney, Carolyn A - T-DITT2; Combs, Chuck - LT-7
Subject: ITRC Report for Approval

Infrastrucure Technical Review Committee

Attached is the revised report and attachments incorporating additions/revisions per comments received by committee members. Significant changes include the following:

- Estimation of societal cost of outages for the "do nothing" alternative
- Corrections to estimating event probability and mean time between failure
- Addition of tables addressing various risks for G10 and G12
- Explicit summarizing of factors applying to the decision for project G10
- Emphaisis that non-transmission alternatives will be pursued in parallel for project G12
- Inclusion of the phrase "...with appropriate credit provisions" (report page 5) in reference to projects funded by generation providers to avoid risk of stranded investment
- Emphais that project G13 will be expedited through the Regional Planning Process this year and then resubmitted to the ITRC.

Please review the report and return by mail and fax a signed copy of the cover letter to me by Wednesday July 31, 2002. My mailing address and fax number is given below. I plan to be out of the office July 22-29. If you have questions during that time please contact Brian Silverstein at (360) 619-6651.

Thanks very much for your participation and support in completing this report!

Bill Mittelstadt

William Mittelstadt TOM
Bonneville Power Administration
Parkway Plaza (Mail Center)
8100 NE Parkway
Vancouver, WA 98662
(360) 619-6672
(360) 619-6945 fax

Cover Letter 7~19.doc | Report Draft 7~19.doc | Appendix A.doc | Appendix B.doc | Appendix C 7~19.doc | Appendix D.doc | Appendix E.doc

William A Mittelstadt
(E-mail)...

July 19, 2002

Addressees

Subject: Infrastructure Technical Review Committee (ITRC) Report

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002).

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority as well as full consideration of third party financing options. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The ITRC was formed in 2001 at the behest of some BPA's customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Once a year, the ITRC evaluates and prioritizes BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC) and the Operating Committee (OC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not finance the work of the ITRC.

The committee provided its first report on August 30, 2001 with the recommendation that BPA install necessary system facilities as soon as possible. A critical first step is securing additional borrowing authority for BPA.

Attached is the second annual report on the transmission infrastructure proposal that contains the conclusions and recommendations of the review committee. The report addresses four additional projects.

- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G12 (Olympic Peninsula Reinforcement) is also important, although the need date is later than initially estimated based on the most recent load forecasts. Opportunities for non-transmission alternatives should be pursued in parallel with the proposed transmission plan and be considered in the final determination.
- Project G13 (Paul – Troutdale 500-kV Line) will continue to go through the WECC Regional Planning Process this year in expectation that it will be ready to be considered by the ITRC in 2003.
- Project G14 (Hanford-Ostrander 500 kV loop-in) requires further analysis by BPA.

The report also asks BPA to present any additional proposed major projects for consideration next year.

Ken Morris PacifiCorp	John Martinsen Snohomish PUD	Wayman Robinett Puget Sound Energy
Hardev Juj Seattle City Light	Scott Waples AvistaCorp	Ronald Schellberg Idaho Power Company
John Leland NorthWestern Energy	Jim Eden PGE Company	

cc
Infrastructure Technical Review Committee

Upgrading the Capacity and Reliability of the BPA Transmission System

Report of the Infrastructure Technical Review Committee

July 19, 2002

Table of Contents

Please refer to the August 30, 2001 Infrastructure Review Committee report for information on the purpose of this Committee, terms of engagement and general system need. Also please refer to this report for system maps.

1. Executive Summary

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002). Problems with the transmission in the region are manifested in several ways:

- Chronic congestion existing on a number of transmission paths requires curtailment of both firm power deliveries and economy energy.
- Resolution of the Western energy crisis requires development of new generating resources. The vast majority of proposed Northwest resources cannot obtain firm transmission service, or be integrated, without additional bulk transmission.
- While power loads have been growing steadily at 1.8% annually and the use of the transmission system is up by over 2% annually, few bulk grid transmission lines were added in the past 15 years.
- It will take much longer to site and build transmission to deliver needed new generation than it will take to build and site the generation. New transmission is needed to meet existing and future obligations in order to comply with recently adopted national and regional standards that ensure a reliable power system.
- It is extremely difficult to meet obligations when facilities are removed from service to conduct normal maintenance or to construct new facilities.

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The Infrastructure Technical Review Committee (ITRC) was formed in 2001 at the behest of some of BPA's customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Once a year, the ITRC evaluates and prioritizes BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC), Operating Committee (OC) and the Northwest Regional Transmission Association (NRTA) Planning Committee (PC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not fund the work of the ITRC.

The committee was asked to report its initial recommendations by August 30, 2001 to enable BPA to install necessary system facilities as soon as possible.

This review is the second in an annual process to coincide with BPA's annual budget cycle. It covers four projects of BPA's infrastructure proposal. Review of additional projects will be conducted in subsequent years. There are several additional parallel efforts that provide for review of proposed transmission additions. This committee's analysis and recommendations will be shared and further analyzed in the following forums.

- Northwest Power Pool (NWPP) Transmission Planning Committee
- Western Electricity Coordinating Council (WECC) Regional Planning Group
- National Environmental Policy Act (NEPA) review for individual projects

During the first part of 2002 the committee met twice to review additional infrastructure proposal developed by BPA. While some of the proposals have been under development in previous forums with outside participation, other proposals were presented for the first time. The committee has reached the following conclusions and recommendations based on its review:

- There continues to be a compelling and immediate need to upgrade portions of the Northwest bulk transmission grid. Solutions proposed by BPA in coordination with others address the identified problems.
- Projects evaluated in the first review should continue on the revised timetable proposed by BPA. BPA should continue to reevaluate project need and timelines, particularly for projects driven by generation integration.
- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G12 (Olympic Peninsula Reinforcement) is also important, although the need date is later than initially estimated based on the most recent load forecasts. Opportunities for non-transmission alternatives should be pursued in parallel with the proposed transmission fix.
- Projects G13 (Paul – Troutdale 500-kV Line) and G14 (Hanford-Ostrander 500 kV loop-in) were examined on a preliminary basis. Project G13 is critical to integration of new generation in the I-5 corridor. BPA should complete details of the plan of service over the next 60 days and bring this through the WECC Regional Planning Process. In addition, coordination with PGE is required. The benefits of project G14 are not clear given proposed I5 generation development and potential higher costs to route around the Columbia Gorge Scenic Area. BPA should bring these projects forward to the committee for consideration in 2003 after further examination of alternatives and need.
- The need still remains to increase BPA borrowing authority for *transmission* by at least $1 billion in order to ensure that sufficient financial resources are available to accomplish transmission expansion over a ten-year planning horizon (see Figure 1, TBL Capital Projects Historical & Future, on page 7).

- BPA should continue to pursue and evaluate third party financing opportunities for major new transmission projects.
- Preliminary analysis has shown that increased transmission use will recover the cost of the proposed capital additions. Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure 10 to 20 year firm transmission service contracts with appropriate credit provisions before proceeding with construction. (Note: BPA's transmission investments are repaid by its transmission customers, not taxpayers.)
- Additional reinforcements by BPA and others are needed to maximize reliability and transfer capability from the proposals. Other Northwest utilities have planned transmission additions, and maximum benefits will be achieved through coordinated development.
- Future reviews should be conducted annually to evaluate and prioritize BPA proposed major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. In accordance with provisions in the January 15, 2002 guidelines[1] BPA provided a status report on projects that were approved last year. There were no significant changes in circumstances that necessitated any of these projects be returned to the committee for a full review.

2. Projects for 2002 Review

Project List

Project		Cost (loaded) ($M)	Energization Date	Capacity Added MW
Portland Area Additions	G10	9	2003	300
Olympic Peninsula Reinforcement	G12	26	2005	430
Total		35		

Project Drivers

	Load Service	Entitlement Return	Generation Integration	Transfers	Reliability	O&M Savings	BiOp
G10	x				x		
G12	x				x		

3. Glossary of Acronyms and Terms

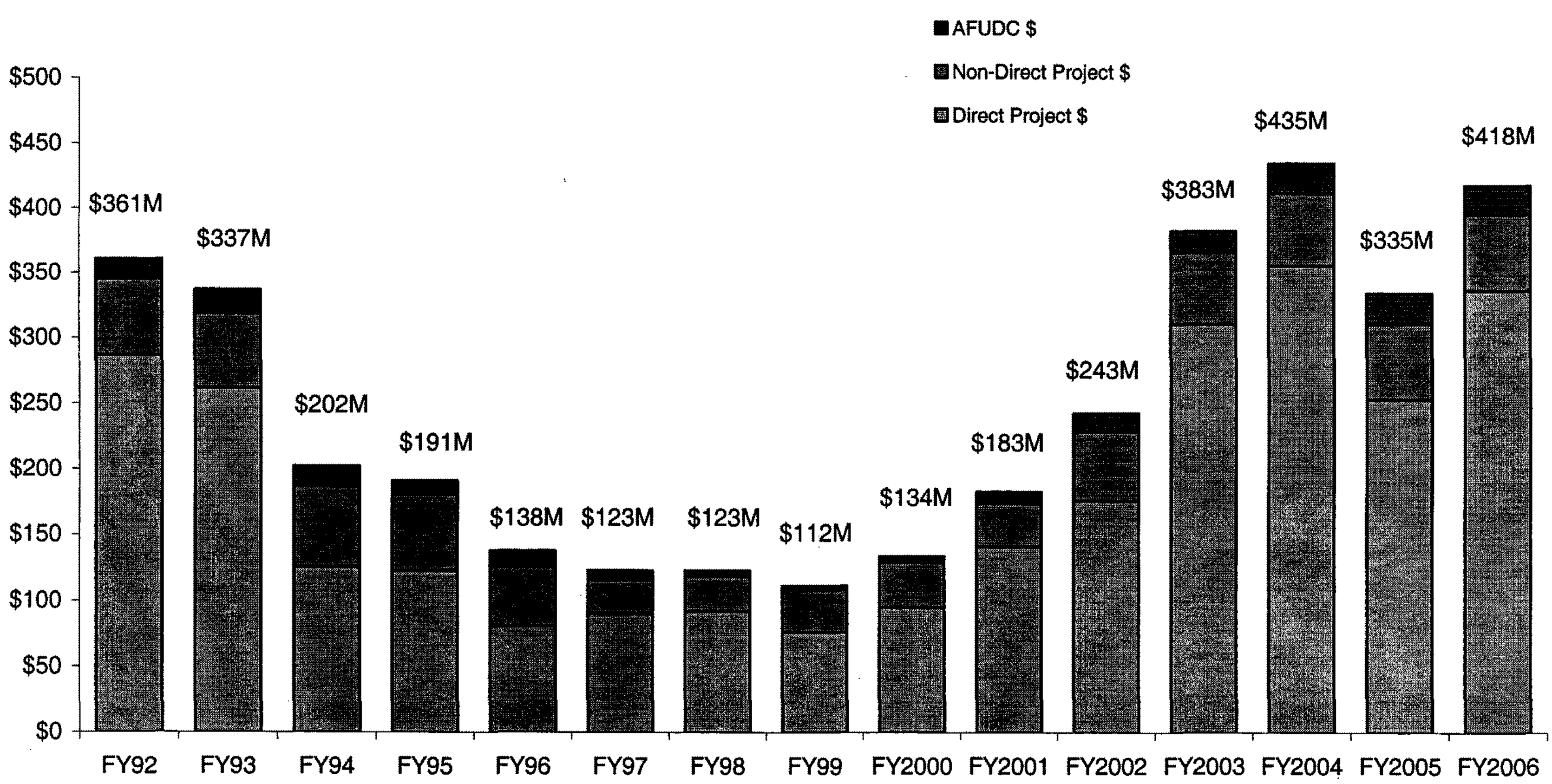
BiOp	Biological Opinion
MW	A unit of power. One MW would serve approximately 700 homes.
NRTA	Northwest Regional Transmission Association
NWPP	Northwest Power Pool
RTO	Regional Transmission Organization
WECC	Western Electricity Coordinating Council

Bulk Transmission – Transmission lines that serve as the backbone of the grid, typically operated at voltages of 230-kV and above.

4. References

[1] "Annual BPA Transmission Infrastructure Review," January 15, 2002.

Figure 1. TBL Capital Projects Historical & Future Trend



Appendix A – Participants

Infrastructure Technical Review Committee Participants

Name		With	Phone	E-Mail	Note
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Silverstein	Brian	BPAT	360.619.6651	blsilverstein@bpa.gov	
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VanZandt	Vickie	BPAT	360.418.8459	vrvanzandt@bpa.gov	

Appendix B –Project Schedules

Project		Energization
Kangley - Echo Lake 500 kV line	G1	Fall 2003*
Schultz - Black Rock 500 kV line	G2	Fall 2004
McNary - John Day 500 kV line	G3	Fall 2004
Lo Monumental - Starbuck 500 kV line	G4	Fall 2004**
Smiths Harbor - McNary 500 kV line	G5	Fall 2004**
Schultz series capacitors	G6	Fall 2003
Celilo Modernization	G7	Summer 2004*
Monroe - Echo Lake 500 kV line	G8	Fall 2005
Bell - Coulee 500 kV line	G9	Fall 2004
Pearl Transformer	G10	Fall 2003
South Seattle Transformer	G11	Fall 2004**
Olympic Pennsula Reinforcement	G12	Fall 2006*,**
Paul - Troutdale 500 kV line	G13	Fall 2005
Hanford - Ostrander loop-in	G14	Spring 2005**

*Denotes change from September, 2001 report
**Energization may change depending on need

Appendix C – Project Summaries

G10. Portland Area Additions (Pearl 500/230 kV Transformer)

Background

The Portland area is currently served by four 500/230 kV transformers: Troutdale on the east side, McLoughlin in SE Portland, Pearl in SW Portland and Keeler on the west side. This project is another phase of reinforcing the load serving capability from the bulk transmission system into the greater Portland area. Earlier reinforcements included adding a new 230 kV double-circuit line between Pearl and PGE's Sherwood substation.

Addition of the 2nd transformer at Pearl will require extension of both the 500 kV and the 230 kV buses. These extensions are within the existing Pearl substation.

Limiting Outages Addressed

Existing Pearl 500/230 kV Transformer

Benefit – Load Area Service

This project will increase the load carrying capability into the greater Portland area. Without this project it would be necessary to trip off load in the Portland area to relieve overloads during abnormal cold winter peaks for an outage of the existing Pearl transformer.

Business Case

This project provides the capacity to carry additional load in the Portland area at the rate of 75 MW per year from 2004 though 2007. Beyond that date it will provide load serving benefit to the capacity of the bank following a suitable plan to address the Big Eddy – Ostrander 500 kV line outage. For the purpose of this analysis the benefit stream is limited to 300 MW for the period beyond 2007. In the Table below, Alternative 1 is the preferred plan. Alternatives 2-5 are described on the next page.

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV	Rev/C	Repayment Years	In Service	Life
1	30.8	11.2	19.6	2.75	6	2003	2037
2	30.8	32.6	(1.8)	0.95	14	2003	2037
3	30.8	54.4	(23.7)	0.57	25	2003	2037
1a (0.9%)	26.9	11.9	15.0	2.26	8	2003	2037

Risk Factors

The following table qualitatively addresses various risk factors:

Factor	Risk	Factor	Risk
Cost	Invoiced	Delivery on time	In inventory
Siting/ROW	Existing site	Funding	Available
Load Growth	See sensitivity 1a	Discount Rate	Not considered

The proposed site has space reserved for the transformer addition. Since this does not involve work outside the substation there are no environmental risks. The Revenue/Cost ratio remains favorable with half the of the projected load growth (1a). Accordingly, this is considered to be a very low risk project.

Project Description (Alternative 1)

This project adds a 2^{nd} 500/230 kV transformer at the existing Pearl Substation. The new transformer will be 3 single-phase units (433 MVA each). The new bank will be equipped with a 9 step LTC and a tertiary for station service. One 500 kV breaker and one 230 kV breaker will be added. The 500 kV and 230 kV buses will be extended.

Alternatives Considered

2. Install a 500/230 kV transformer at PGE's Sherwood Substation. This location would be higher cost, require additional property and would be difficult to site. It was considered in the past, but the decision was made to increase the 230 kV capacity between Pearl and Sherwood.
3. Install a 500/230 kV transformer at McLaughlin Substation.
4. Curtail load in the event of a transformer outage (Do Nothing).
5. Non-transmission alternatives.

Do-Nothing Alternative (#4)

The "no build" alternative represents the risk of load interruption for a first contingency 500/230 transformer outage at any of the four following locations: Keeler; Pearl; McLaughlin; Troutdale. Load interrupted ranges from 75 MW in 2004 to 900 MW in 2015. Based on a single phase transformer outage failure rate of once per100 years the outage mean time between failure (MTBF) is estimated as follows:

P(no outage) = (1-1/100)^(4 banks*3 transformers/bank)
P(no outage) = 0.886
P(outage) = 1-0.886 = 0.114
MTBF = 1/0.114 = 8.8 years

While the revenues for the do-nothing alternative can be assumed to be the same assuming load can be carried under the no-outage condition, the societal cost of a bank outage would be significant. Assuming that load is curtailed to the remaining system capability for a period of one week until a new transformer unit is installed the present worth societal cost over ten years of service is estimated to be about $4.9 M. This is calculated using the above MTBF estimate, the following load interruption cost figures inflated yearly by 2.64% and assuming the system exposure is 8 hours/day for two months/year.

Load Type	Composition	$/kWHr (2002)
Residential	50%	$1.66
Commercial	30%	$18.50
Industrial	20%	$27.56

Non-Transmission Alternatives (#5)
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and Environmental Economics, Nov. 2001 available at:

http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm.

Non-transmission alternatives can not be implemented in time to be considered a viable alternative to this project.

Decision
BPA chose the preferred plan for the following reasons:

- Lowest cost
- Essentially no environmental impact (existing site)
- Favorable Revenue/Cost ratio (2.75)
- Favorable economics under reduced load growth rate
- Short repayment period (6 years)

Energization Date: **Fall 2003 (Preferred Alternative)**
Estimated Cost: **$9M**

G12. Olympic Peninsula Reinforcement (Paul-Shelton 500-kV line)

Background
The Olympic Peninsula area load is served from Olympia substation via 230-kV and 115-kV transmission. The major source to Olympia to serve these loads is the 500-kV transmission line from Paul substation. An outage of this 500-kV source to Olympia would result in a voltage collapse during extra heavy winter load conditions. A second 500-kV source is needed to solve the voltage collapse problem as early as 2003. A shunt capacitor group to be installed in 2003 will delay the need for this project until 2005. With this addition the Olympic Peninsula transmission system has reached the limit that can be supported by shunt capacitors. A total of 20 capacitor groups amounting to approximately 900 MVAR will have been installed.

In addition, a double-line outage of the 230-kV double-circuit line from Olympia to Shelton or a breaker failure at Olympia will result in a total loss of the Olympic Peninsula during normal winter load. The proposed reinforcement will solve both the N-1 and N-2 problems and reinforce the Olympic Peninsula region.

Limiting Outages Addressed
- Olympia 500/230-kV transformer
- Paul-Olympia 500-kV line
- Olympia-Shelton 230-kV double line
- Olympia 230-kV breaker failure

Benefit - Load Area Service
This project will prevent these outages from impacting service to the Olympic Peninsula by providing a second source of power to the Peninsula from Paul Substation. This project will also increase the load service capability to the Olympic Peninsula under non-outage conditions as well as mitigate or delay other system upgrades that would be needed in the future if this project were not built.

Business Case
This project provides the capacity to carry additional projected normal winter load in the Olympic Peninsula area in compliance with NERC/WECC Planning Standards for Category A-C outages. For the purpose of this analysis revenues are based on 1.8% load growth corresponding to 26 MW/year reaching a project limit of 338 MW in 2019. In the Table below, Alternative 1 is the proposed plan and Alternative 2 would involve moving the 500/230-kV transformer to Olympia (see below). Alternatives 1a-1c are sensitivity studies discussed under "Risk.".

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV	Rev/C	Repayment Years	In Service	Life
1	21.6	29.3	(7.8)	0.74	20	2006	2040
1a	35.7	35.5	0.2	1.00	20	2006	2040
1b	14.4	34.1	(19.7)	0.42	31	2006	2040
1c	21.6	32.7	(11.1)	0.66	22	2006	2040

2	21.6	27.2	(5.7)	0.79	19	2006	2040

Risk

The following table qualitatively addresses various risk factors. Three are identified for evaluation.

Factor	Risk	Factor	Risk
Cost	**See sensitivity 1c**	Delivery on time	Routine purchases
Siting/ROW	Existing site/ROW	Funding	Available
Load Growth	**See sensitivity 1b**	Discount Rate	**See sensitivity 1a**

Sensitivity 1a – This case determines what discount rate is needed to achieve a Revenue/Cost ratio of 1.0. This is achieved by a discount rate of 6.5%, giving an equivalent rate of return on investment of 6.5% over the 34 year life of the project.
Sensitivity 1b – In this case the load growth rate of 1.8% is cut in half to 0.9%. This reduces the Revenue/Cost ratio from 0.74 to 0.42 and extends the repayment period from 20 years to 31 years.
Sensitivity 1c – This case represents an increase in project cost of 10%. The Revenue/Cost ratio for this case dropped from 0.74 to 0.66 and the repayment period increased from 20 years to 22 years.

Project Description

- Build approximately 13.8 miles of 500-kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to the Shelton 500 kV yard. The line will be routed on the existing Olympia-Shelton right of way. Cut the Paul-Satsop 500 kV line at corridor intersection and connect the Paul end to new 500 kV line to Shelton.
- Remove Olympia-Shelton 115 kV line #1 from Olympia to Dayton Tap.
- Construct a 500 kV yard approximately 1 mile south of the existing Shelton substation, move Satsop 500/230 kV transformer to this location and tie it to Shelton 230 kV bus via 1 mile long 230 kV line.
- Build approximately 6 miles of new 230 kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to Olympia substation. Connect this new line to Satsop end of cut Paul-Satsop 500 kV line.

Alternatives Considered

2. Move Satsop 500/230 kV transformer to Olympia substation and terminate the Paul-Satsop 500 kV line at Olympia.
3. No build alternative
4. Non-transmission alternatives

Do-Nothing Alternative (#3)

(a) The following information applies to voltage collapse for N-1 contingencies for extra heavy winter if the transmission system is not reinforced:

- A 2 year MTBF for N-1 Paul-Olympia 500 kV line with average outage duration of 2.5 hours.

- A 100 year MTBF each phase of the Olympia 500/230 transformer and a 4 week replacement time. This corresponds to a bank outage probability of:

  P(outage) = 1-(1-1/100)^3 = 0.030, and a
  MTBF = 1/0.030 = 34 years.

- The required load curtailment for either outage increases by 26 MW yearly starting in 2006.

Since the outage time is quite different for the two events the societal costs are estimated separately. Voltage collapse is assumed to occur when the demand exceeds capacity following the outage by more than 100 MW. Area load is restored to the capability of the remaining system within one hour. Using the same customer outage costs as with G10 the present worth societal costs of the N-1 line outage is $1 M and the N-1 bank outage is $5.65 M for a ten year period.

(b) The following information was used to estimate the probability of loss of load for N-2 contingencies if the transmission system is not reinforced:

- 9.3 year MTBF for N-2 outage of Olympia – Shelton 230 kV lines 3 and 4. It is further assumed that one line can be restored within one hour and the second line within 24 hours.
- 0.018 breaker failures/year for each of eight breakers at Olympia. It is assumed that full service is restored within one hour by moving the affected line over to the bus tie breaker. This corresponds to a bus outage probability of

  P(outage) = 1-(1-0.018)^8 = 0.14, and a
  MTBF = 1/0.14 = 7.4 years.

Again, the societal costs of the two events are treated separately. In each case it is assumed that the entire area load will be lost due to voltage collapse for the initial period of one hour. The estimated present worth societal costs are: $5.06 M for the two-line outage and $500 K for the breaker failure outages.

Overall then the estimated present worth societal cost for a ten year period of the do-nothing alternative is approximately $15.7 M. The present value savings of a ten-year delay in the project is expected to be greater considering deferred capital, financing and O&M costs.

Non-Transmission Alternatives (#4)
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and Environmental Economics, Nov. 2001 available at
http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm.

These measures could cost-effectively defer the need under N-1 contingencies, although they can not address the N-2 problems. BPA will further consider non-transmission alternatives before proceeding with this project. Cost information is not available at this time to allow presentation of an economic analysis.

Decision

BPA has selected a preferred transmission plan from the alternatives considered, but has elected to defer a decision on the project to allow time for further development of the non-transmission alternative (#5) and to consider public input before proceeding.

Of the transmission alternatives considered, the preferred plan is Alternative 1 because it outperforms the Olympia option for both N-2 critical outages for essentially the same present worth cost without O&M expenses included. O&M costs would be higher for the Olympia option based on the amount of extra equipment that would be needed at the Olympia substation. The Olympia option would require major 230 kV work at the Olympia substation, including expansion of the 230 kV yard. Land would also have to be purchased around the 500 kV yard for 230 kV line routing into the 230 kV bus. Some of the line routing into the 230 kV bus may not even be physically possible based on current line routing, tower and road locations, land needs and right-of-way widths. The Shelton option has 8 MW less losses than the Olympia option based on 1170 MW of load, which is equivalent to normal winter load in 2002-03. These losses will increase with increases in load. The Shelton option would leave the system better prepared for the future.

BPA will further consider non-transmission alternatives before proceeding with this project.

Energization Date: Fall 2006
Estimated Cost: $23-26 M

G13. Paul – Troutdale 500-kV Line

Background

The existing I-5 corridor transmission system is limited to:
- 2400 MW North of Allston by a double Paul – Allston 500-kV line outage
- 1650 MW South of Allston by the Allston – Keeler 500-kV line outage

With new generation projects proposed in the area, the existing system is not adequate to provide transmission service to most new generating projects on a firm basis, likely resulting in generation curtailments.

At present, the double Paul – Allston 500-kV line outage requires 2850 MW generation dropping and opening of both Chehalis – Longview 230-kV line that run in parallel to the Paul – Allston line. This sectionalizing removes the northern feed into Portland metro area, resulting in load service only from the east side through Ostrander. Sectionalizing greatly reduces reactive margins in the system, which will become a limiting factor as load grows in Portland area. Sectionalizing was also shown to degrade transient stability performance.

Currently, the Allston – Keeler 500-kV line outage requires generation dropping up to 2850 MW to prevent thermal overloads. Historic data indicates that there were 19 line outages in the past 16 years, mostly cased either by lightning hits or trees. It is very desirable to reduce generation dropping amount for a single contingency since these are more frequent than multi-contingency outages.

This project is being taken through the WECC Regional Planning process.

Limiting Outages Addressed

Paul – Allston 500-kV double line
Allston – Keeler 500-kV line
Keeler – Pearl 500-kV line
Keeler breaker failure

Benefits

Table 1. Generation projects proposed in the area affecting transmission needs:

Project	Capacity	Energization	North of Allston	South of Allston
Napavine	600	11/1/03	More stress	More stress
Grays Harbor I	630	6/1/03	More stress	More stress
Longview – Enron	300	7/1/03	Less stress	More stress
Mint Farm	280	5/1/03	Less stress	More stress
Summit	530	11/1/03	Less stress	More stress
Big Hanaford	250	1/1/02	More stress	More stress
Port Westward	650	12/31/03	Less stress	More stress
Centralia efficiency	+ 70	Done	More stress	More stress
Grays Harbor II	630	11/1/04	More stress	More stress

It is evident that new generation will greatly increase stress the constrained I-5 paths. The existing system is not adequate to provide transmission service to most generating projects on firm basis, very likely resulting in generation curtailments. The new 500-kV line is expected to provide firm transmission rights for the proposed projects in the area.

A. Transfer Increase

It is expected that South of Allston limit will increase from 1650 MW to 2,700 – 2,900 MW. The new line will eliminate or greatly reduce the need for generation dropping for N-1 outages. The time to thermal overload will allow to ramp down generation of dropping. Upgrades of parallel 115-kV and 230-kV lines may be required to get the full capacity.

B. Load Service in Winter Conditions

Studies are under way.

Business Case
This project is driven by requests for long-term firm transmission by new generation and imports. Parties requesting transmission would be expected to fund the upgrade consistent with FERC policy.

Risk
The risk associated with this project is small because the generators will be expected to finance the transmission investment and/or commit to long-term transmission service.

Project Description
At present time, the plan of service is not fully defined. Two conceptual options have been considered and studied for electrical performance. Alternative #1 includes a 500-kV line from near Longview to Troutdale, and alternative #2 is a 500-kV line from near Longview to Pearl.

Decision
No preferred alternative is proposed at this time. The project will be returned to the Technical Review Committee for consideration in 2003 following the WECC Regional Planning Process.

Energization Date: **Fall 2005**
Estimated Cost: **$117-155 M**

G14. North of John Day/Portland Area Reinforcement – (Loop the Hanford-Ostrander 500-kV line into Big Eddy)

Background
The proposed new generation additions around the McNary area along with the new McNary-John Day 500-kV line will increase the stress across the North of John Day and the flow between John Day and Big Eddy. This project will relieve some of the North of John Day constraint and reinforce the transmission between John Day and Big Eddy. In addition, this project will also reinforce the bulk load serving capability into the greater Portland area. During abnormal cold weather, an outage of the Bid Eddy-Ostrander 500-kV line results in voltage collapse in the Portland area. This Project will in effect create a second Big Eddy – Ostrander 500-kV line and increase the load serving capability to the Portland area.

Limiting Outages Addressed
Ashe-Marion/Slatt-Buckley 500-kV double line loss (summer)
John Day-Big Eddy 500-kV double line loss (summer)
Slatt 500-kV breaker failures (summer)
Big Eddy-Ostrander 500-kV line (winter)
Pearl 500-kV breaker failures (winter)

Benefit – Congestion Relief and Load Area Support
This project will increase the North of John Day capability by approximately 250-300 MW and increase the capability between John Day and Big Eddy by approximately 600-700 MW. This project also reinforces the bulk grid to serve greater Portland area load and eliminate the need for building second Big Eddy-Ostrander 500-kV line.

Business Case
The primary drivers of this project is North to South network transfers and provide additional network capacity for service to the Portland area load. The estimated cost recovery of this project at current rates and for the alternatives considered is over 35 years. In view of the long payback period lower cost alternatives or deferral will be considered.

Risk
The benefit ascribed to this project for the Portland area load is related to the timing of the Paul – Troutdale project which in part serves this need. The portion of benefits ascribed to intertie support will be beneficial at the time the project goes into service but is not sufficient alone to ensure full cost recovery. Risk that costs will not be recovered for this project as proposed at this point is high.

Project Description

- This project consists of constructing approximately 16.5 miles of 500-kV double circuit line to the Columbia River crossing and approximately 18 miles of single circuit 500-kV line to Big Eddy and 2 miles of line to John Day.

- Develop a new 500-kV switching station next to the existing Hanford (Wautoma) – Ostrander 500-kV line and loop in the Hanford-Ostrander line into the new switching station.
- Add terminals at Big Eddy and John Day to terminate the new lines.

Preliminary Alternatives

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit.

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit and build a third 20miles of single circuit 500-kV line between John Day and Big Eddy

Decision

No preferred alternative is proposed at this time. The project may be returned to the Technical Review Committee for consideration in 2003 following further analysis.

Energization Date: Spring 2006
Estimated Cost: $70-90M

Appendix D - Economic Analysis

The analysis used for projects G10 and G12 was conducted using Excel spreadsheet calculations. The following indicators of economic performance were computed:

- Repayment time (years from in service date)
- Net Present Value
- Benefit to Cost Ratio

The basic economic assumptions used were as follows:

Discount Rate		9.00%
Inflation Rate		2.64%
BPA Financing Rate		6.75%
O&M Escalation		0.00%
BPA Rate Escalation		0.00%
O&M Actual		2.64%
BPA Rate Actual		2.64%

The high discount rate of 9% favors projects with a faster payback period. A lower discount rate would increase benefit/cost ratio for projects G10 and G12. The treasury borrowing rate of 6.75% represents recent historical BPA borrowing.

Net Present Value and Benefit to Cost were computed using a substation equipment service life of 34 years[1] since both projects G10 and G12 have major substation components.

Capital cost expenditures were distributed over the expected year of obligation over the construction period.

BPA transmission revenues were reckoned at the rate of $1.013 $/kW-mo (12.156 $/kW-year).

Projects G10 and G12 assume that 75% of the load increase is transmission revenue producing. Assuming 50% revenue producing reduces the benefit to cost ratios by about 1/3.

Typical operations and maintenance costs are used.[1]

[1] Annual Financial Requirements for Bonneville Power Administration Transmission System and revised Operation and Maintenance Tables, Larry Davidson, March 31, 2000.

Appendix E –Supplemental Cost Estimates

G-10 Preferred Plan (cost estimate)

Add a 500/230 kV transformer at BPA's Pearl Substation.
(work order quality estimate)

Requirements:

Add a 500 kV transformer	$
Expand 230 kV yard, 1-230 kV breaker	$
Expand 500 kV yard, add 1-500 kV breaker	$
Associated relays and controls	$
TOTAL	**$8.2m**

G-10 Alternatives (cost estimates)

The following alternatives to the Pearl 500/230 kV transformer were considered.
("back-of-the-envelope" estimates, work required in other PGE's substations)

1. **Add the transformer at PGE's Sherwood substation**

Requirements:

Acquire property	$2.0m
Add a 500/230 kV Tx	$8.0m
3-500 kv breaker ring bus	$6.0m
1-230 kv breaker	$1.0m
Associated relaying and controls	$2.5m
500 kV line work	$2.0m
Other line relocations	$3.0m
TOTAL	**$24.5m**

2. **Add the transformer at McLoughlin substation**

Requirements:

Add 11.7 mi of 1272 Narcissus conductor. (on vacant side of tower)	$2.0m
Add 2-230 kV breakers at McLoughlin.	$2.0m
Add a 2nd 500/230 kV transformer at McLoughlin	$8.0m
9 miles of 500 kV line. OST_MCL	$9.0m
4-500 kV breaker ring bus @McLoughlin (may be difficult)	$8.0m
New 500 kV bay at Ostrander	$3.0m
Associated relaying and controls	$2.0m
2-230 kV breakers at Pearl	$2.0m
TOTAL	**$36.0m**

Wright, April E - KFF-2

From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Tuesday, July 30, 2002 1:48 PM
To: 'Morris, Ken'; 'Martinsen, John'; 'Robinett, Wayman'; 'Juj, Hardev'; 'Waples, Scott'; 'Schellberg, Ron'; 'Leland, John'; 'Eden, Jim'
Cc: Silverstein, Brian L - TOP-PPO2-2
Subject: FW: ITRC Report for Approval

Hi

This is a friendly reminder that tomorrow July 31 is the request date for returning a signed copy of the cover letter to me by mail and fax.

Thanks,

Bill

William A Mittelstadt
(E-mail)...

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Friday, July 19, 2002 4:35 PM
To: Brattebo, Scott; Carr, Geoff; CARTER, LAWRENCE; Eden, Jim; Elizeh, Edison; 'Goddard, Richard'; Groce, Ed; HORVATH, JULIUS; Johnson, Don; Juj, Hardev; KEENAN, GERALD; Kinney, Scott; KOSTEREV, DMITRY; LANDAUER, MARVIN; Leland, John; Lu, Franklin; Martinsen, John; Morris, Ken; Phillips, John; QUINATA, JOHN; Reedy, Dana; RODRIGUES, MELVIN; Rust, Jerry; RYDELL, KENDALL; Schellberg, Ron; Seabrook, Joe; SILVERSTEIN, BRIAN; STADLER, LAWRENCE; VANZANDT, VICKIE; Waples, Scott
Cc: Haner, John - TOM-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2; Maher, Mark W - T-DITT2; Whitney, Carolyn A - T-DITT2; Combs, Chuck - LT-7
Subject: ITRC Report for Approval

Infrastrucure Technical Review Committee

Attached is the revised report and attachments incorporating additions/revisions per comments received by committee members. Significant changes include the following:

- Estimation of societal cost of outages for the "do nothing" alternative
- Corrections to estimating event probability and mean time between failure
- Addition of tables addressing various risks for G10 and G12
- Explicit summarizing of factors applying to the decision for project G10
- Emphaisis that non-transmission alternatives will be pursued in parallel for project G12
- Inclusion of the phrase "...with appropriate credit provisions" (report page 5) in reference to projects funded by generation providers to avoid risk of stranded investment
- Emphais that project G13 will be expedited through the Regional Planning Process this year and then resubmitted to the ITRC.

Please review the report and return by mail and fax a signed copy of the cover letter to me by Wednesday July 31, 2002. My mailing address and fax number is given below. I plan to be out of the office July 22-29. If you have questions during that time please contact Brian Silverstein at (360) 619-6651.

Thanks very much for your participation and support in completing this report!

Bill Mittelstadt

William Mittelstadt TOM
Bonneville Power Administration
Parkway Plaza (Mail Center)
8100 NE Parkway
Vancouver, WA 98662
(360) 619-6672
(360) 619-6945 fax

William A Mittelstadt
(E-mail)...

Wright, April E - KFF-2

From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Monday, August 05, 2002 10:34 AM
To: 'Morris, Ken'; 'Martinsen, John'; 'Robinett, Wayman'; 'Juj, Hardev'; 'Waples, Scott'; 'Schellberg, Ron'; 'Leland, John'; 'Eden, Jim'
Cc: 'Goddard, Richard'; VanZandt, Vickie - TO-DITT2; Mittelstadt, Bill - TOM-PPO2-2; Rodrigues, Melvin - TOP-PPO2-2; 'Groce, Ed'
Subject: ITRC Report

Importance: High

ITRC

Thanks to those who have responded by sending a signed copy of the signature page and those who have been in contact with me and plan to complete that this week. I have received a number of comments on improving the text and flow of Appendix C from Jim Eden which are helpful. Attached is an updated copy of the report and a file summarizing the changes that have been received and incorporated. These changes do not alter the substance of the report and should not cause any problem for those who have already replied. The cover letter is unchanged.

For those who have not replyed yet please take the time reply by fax (360) 619-6945 with a signed copy of the cover letter and a hard copy in the mail. My goal is to distribute the report next week to your management representatives and the BPA administrator as was done last year indicating completion of this assignment to us.

I realize that this is a very busy time and also some may be out for vacation. Thanks for your help on this effort.

Bill Mittelstadt

Signed copies received from:
John Leland
John Martinsen
Ron Schellberg

Phone/email replies received from:
Jim Eden (editorial changes included)
Ken Morris

Cover Letter 7~19.doc

Report Draft 8~1.doc

Appendix A 7~31.doc

Appendix B 8~1.doc

Appendix C 8~1.doc

Appendix D.doc

Clarifications and Editorial C...

William A Mittelstadt (E-mail)...

August 12, 2002

Addressees

Subject: Infrastructure Technical Review Committee (ITRC) Report

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002).

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority as well as full consideration of third party financing options. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The ITRC was formed in 2001 at the behest of some BPA customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Once a year, the ITRC evaluates and prioritizes BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC) and the Operating Committee (OC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not finance the work of the ITRC.

The committee provided its first report on August 30, 2001 with the recommendation that BPA install necessary system facilities as soon as possible. A critical first step is securing additional borrowing authority for BPA.

Attached is the second annual report on the transmission infrastructure proposal that contains the conclusions and recommendations of the review committee. The report addresses four additional projects.

- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G12 (Olympic Peninsula Reinforcement) is also important, although the need date is later than initially estimated based on the most recent load forecasts. Opportunities for non-transmission alternatives should be pursued in parallel with the proposed transmission plan and be considered in the final determination.
- Project G13 (Paul – Troutdale 500-kV Line) will continue to go through the WECC Regional Planning Process this year in expectation that it will be ready to be considered by the ITRC in 2003.
- Project G14 (Hanford-Ostrander 500 kV loop-in) requires further analysis by BPA.

The report also asks BPA to present any additional proposed major projects for consideration next year.

Ken Morris
PacifiCorp

John Martinsen
Snohomish PUD

Wayman Robinett
Puget Sound Energy

Hardev Juj
Seattle City Light

Scott Waples
AvistaCorp

Ronald Schellberg
Idaho Power Company

John Leland
NorthWestern Energy

Jim Eden
PGE Company

cc
Infrastructure Technical Review Committee

Upgrading the Capacity and Reliability of the BPA Transmission System

Report of the Infrastructure Technical Review Committee

August 1, 2002

Table of Contents

Please refer to the August 30, 2001 Infrastructure Review Committee report for information on the purpose of this Committee, terms of engagement and general system need. Also please refer to this report for system maps.

1. Executive Summary

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002). Problems with the transmission in the region are manifested in several ways:

- Chronic congestion existing on a number of transmission paths requires curtailment of both firm power deliveries and economy energy.
- Resolution of the Western energy crisis requires development of new generating resources. The vast majority of proposed Northwest resources cannot obtain firm transmission service, or be integrated, without additional bulk transmission.
- While power loads have been growing steadily at 1.8% annually and the use of the transmission system is up by over 2% annually, few bulk grid transmission lines were added in the past 15 years.
- It will take much longer to site and build transmission to deliver needed new generation than it will take to build and site the generation. New transmission is needed to meet existing and future obligations in order to comply with recently adopted national and regional standards that ensure a reliable power system.
- It is extremely difficult to meet obligations when facilities are removed from service to conduct normal maintenance or to construct new facilities.

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The Infrastructure Technical Review Committee (ITRC) was formed in 2001 at the behest of some of BPA's customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Once a year, the ITRC evaluates and prioritizes BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC), Operating Committee (OC) and the Northwest Regional Transmission Association (NRTA) Planning Committee (PC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not fund the work of the ITRC.

The committee was asked to report its initial recommendations by August 30, 2001 to enable BPA to install necessary system facilities as soon as possible.

This review is the second in an annual process to coincide with BPA's annual budget cycle. It covers four projects of BPA's infrastructure proposal. Review of additional projects will be conducted in subsequent years. There are several additional parallel efforts that provide for review of proposed transmission additions. This committee's analysis and recommendations will be shared and further analyzed in the following forums.

- Northwest Power Pool (NWPP) Transmission Planning Committee
- Western Electricity Coordinating Council (WECC) Regional Planning Group
- National Environmental Policy Act (NEPA) review for individual projects

During the first part of 2002 the committee met twice to review additional infrastructure proposal developed by BPA. While some of the proposals have been under development in previous forums with outside participation, other proposals were presented for the first time. The committee has reached the following conclusions and recommendations based on its review:

- There continues to be a compelling and immediate need to upgrade portions of the Northwest bulk transmission grid. Solutions proposed by BPA in coordination with others address the identified problems.
- Projects evaluated in the first review should continue on the revised timetable proposed by BPA. BPA should continue to reevaluate project need and timelines, particularly for projects driven by generation integration.
- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G11 (South Seattle Transformer) is not addressed at this time and will be submitted for future ITRC review.
- Project G12 (Olympic Peninsula Reinforcement) is also important, although the need date is later than initially estimated based on the most recent load forecasts. Opportunities for non-transmission alternatives should be pursued in parallel with the proposed transmission fix.
- Projects G13 (Paul – Troutdale 500-kV Line) and G14 (Hanford-Ostrander 500 kV loop-in) were examined on a preliminary basis. Project G13 is critical to integration of new generation in the I-5 corridor. BPA should complete details of the plan of service over the next 60 days and bring this through the WECC Regional Planning Process. In addition, coordination with PGE is required. The benefits of project G14 are not clear given proposed I5 generation development and potential higher costs to route around the Columbia Gorge Scenic Area. BPA should bring these projects forward to the committee for consideration in 2003 after further examination of alternatives and need.
- The need still remains to increase BPA borrowing authority for *transmission* by at least $1 billion in order to ensure that sufficient financial resources are available to

accomplish transmission expansion over a ten-year planning horizon (see Figure 1, TBL Capital Projects Historical & Future, on page 7).

- BPA should continue to pursue and evaluate third party financing opportunities for major new transmission projects.
- Preliminary analysis has shown that increased transmission use will recover the cost of the proposed capital additions. Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure 10 to 20 year firm transmission service contracts with appropriate credit provisions before proceeding with construction. (Note: BPA's transmission investments are repaid by its transmission customers, not taxpayers.)
- Additional reinforcements by BPA and others are needed to maximize reliability and transfer capability from the proposals. Other Northwest utilities have planned transmission additions, and maximum benefits will be achieved through coordinated development.
- Future reviews should be conducted annually to evaluate and prioritize BPA proposed major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. In accordance with provisions in the January 15, 2002 guidelines[1] BPA provided a status report on projects that were approved last year. There were no significant changes in circumstances that necessitated any of these projects be returned to the committee for a full review.

2. Projects for 2002 Review

Project List

Project		Cost (loaded) ($M)	Energization Date	Capacity Added MW
Portland Area Additions	G10	9	2003	300
Olympic Peninsula Reinforcement	G12	26	2005	430
Total		35		

Project Drivers

	Load Service	Entitlement Return	Generation Integration	Transfers	Reliability	O&M Savings	BiOp
G10	x				x		
G12	x				x		

3. Glossary of Acronyms and Terms

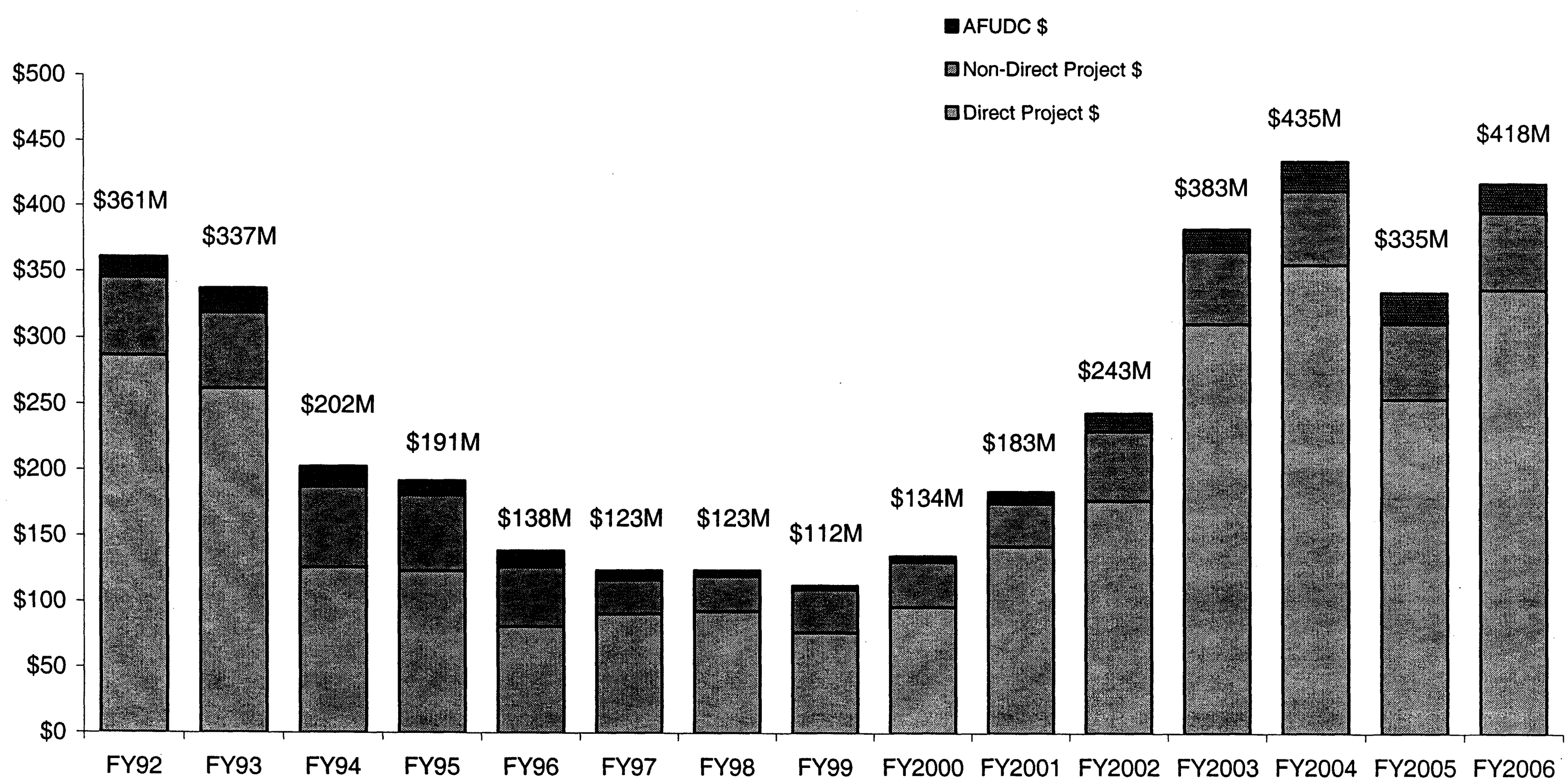
BiOp	Biological Opinion
MW	A unit of power. One MW would serve approximately 700 homes.
NRTA	Northwest Regional Transmission Association
NWPP	Northwest Power Pool
RTO	Regional Transmission Organization
WECC	Western Electricity Coordinating Council

Bulk Transmission – Transmission lines that serve as the backbone of the grid, typically operated at voltages of 230-kV and above.

4. References

[1] "Annual BPA Transmission Infrastructure Review," January 15, 2002.

Figure 1. TBL Capital Projects Historical & Future Trend



Appendix A – Participants

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Appendix B –Project Schedules

Project		Energization
Kangley - Echo Lake 500 kV line	G1	Fall 2003[1]
Schultz - Black Rock 500 kV line	G2	Fall 2004
McNary - John Day 500 kV line	G3	Fall 2004
Lo Monumental - Starbuck 500 kV line	G4	Fall 2004[2]
Smiths Harbor - McNary 500 kV line	G5	Fall 2004[2]
Schultz series capacitors	G6	Fall 2003
Celilo Modernization	G7	Summer 2004[1]
Monroe - Echo Lake 500 kV line	G8	Fall 2005
Bell - Coulee 500 kV line	G9	Fall 2004
Pearl Transformer	G10	Fall 2003
South Seattle Transformer	G11	Fall 2004[2,3]
Olympic Pennsula Reinforcement	G12	Fall 2006[1,2]
Paul - Troutdale 500 kV line	G13	Fall 2005[3]
Hanford - Ostrander loop-in	G14	Spring 2005[2,3]

Notes:
1 Denotes change from September, 2001 report
2 Energization may change depending on need.
3 To be submitted for future ITRC review.

Appendix C – Project Summaries

G10. Portland Area Additions (Pearl 500/230 kV Transformer)

Background

The Portland area is currently served by four 500/230 kV transformers: Troutdale on the east side, McLoughlin in SE Portland, Pearl in SW Portland and Keeler on the west side. This project is another phase of reinforcing the load serving capability from the bulk transmission system into the greater Portland area. Earlier reinforcements included adding a new 230 kV double-circuit line between Pearl and PGE's Sherwood substation.

Addition of the 2nd transformer at Pearl will require extension of both the 500 kV and the 230 kV buses. These extensions are within the existing Pearl substation.

Limiting Outages Addressed
Existing Pearl 500/230 kV Transformer

Benefit – Load Area Service
This project will increase the load carrying capability into the greater Portland area. Without this project it would be necessary to trip off load in the Portland area to relieve overloads during abnormal cold winter peaks for an outage of the existing Pearl transformer.

Business Case

This project provides the capacity to carry additional Portland area load increasing at the rate of 75 MW per year from 2004 though 2007. Beyond that date it will provide load serving benefit to the capacity of the bank following a suitable plan to address the Big Eddy – Ostrander 500 kV line outage. For the purpose of this analysis the benefit stream is limited to 300 MW for the period beyond 2007. In the Table below, Alternative 1 is the preferred plan. Alternatives 2-5 are described on the next page.

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV	Rev/C	Repayment Years	In Service	Life
1	30.8	11.2	19.6	2.75	6	2003	2037
2	30.8	32.6	(1.8)	0.95	14	2003	2037
3	30.8	54.4	(23.7)	0.57	25	2003	2037
1a (0.9%)	26.9	11.9	15.0	2.26	8	2003	2037

Risk Factors

The following table qualitatively addresses various risk factors:

Factor	Risk	Factor	Risk
Cost	Invoiced	Delivery on time	In inventory
Siting/ROW	Existing site	Funding	Available
Load Growth	See sensitivity 1a	Discount Rate	Not considered

The proposed site has space reserved for the transformer addition. Since this does not involve work outside the substation there are no environmental risks. The Revenue/Cost ratio remains favorable with half the of the projected load growth (1a). Accordingly, this is considered to be a very low risk project.

Project Description (Alternative 1)
This project adds a 2^{nd} 500/230 kV transformer at the existing Pearl Substation. The new transformer will be 3 single-phase units (433 MVA each). The new bank will be equipped with a 9 step LTC and a tertiary for station service. One 500 kV breaker and one 230 kV breaker will be added. The 500 kV and 230 kV buses will be extended.

Alternatives Considered

2. Install a 500/230 kV transformer at PGE's Sherwood Substation. This location would be higher cost, require additional property and would be difficult to site. It was considered in the past, but the decision was made to increase the 230 kV capacity between Pearl and Sherwood.
3. Install a 500/230 kV transformer at McLoughlin Substation.
4. Curtail load in the event of a transformer outage (Do Nothing).
5. Non-transmission alternatives.

Alternatives #2 and #3
Alternatives 2 and 3 listed above have capital costs of $24.5 M and #36 M, respectively as compared to $9 M for alternative 1.

Do-Nothing Alternative (#4)
The "no build" alternative represents the risk of load interruption for a first contingency 500/230 transformer outage at any of the four following locations: Keeler; Pearl; McLoughlin; Troutdale. Load interrupted ranges from 75 MW in 2004 to 900 MW in 2015. Based on a single phase transformer outage failure rate of once per100 years the outage mean time between failure (MTBF) is estimated as follows:

P(no outage) = (1-1/100)^(4 banks*3 transformers/bank)
P(no outage) = 0.886
P(outage) = 1-0.886 = 0.114
MTBF = 1/0.114 = 8.8 years

While the revenues for the do-nothing alternative can be assumed to be the same assuming load can be carried under the no-outage condition, the societal cost of a bank outage would be significant. Assuming that load is curtailed to the outage limit for a period of one week until a new transformer unit is installed the present worth societal cost over ten years of service is estimated to be about $4.9 M. This is calculated using the above MTBF estimate, the following load interruption cost figures inflated yearly by 2.64% and assuming the system exposure is 8 hours/day for two months/year.

Load Type	Composition	$/kWHr (2002)
Residential	50%	$1.66
Commercial	30%	$18.50
Industrial	20%	$27.56

Non-Transmission Alternatives (#5)
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and Environmental Economics, Nov. 2001 available at:

http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm.

Non-transmission alternatives can not be implemented in time to be considered a viable alternative to this project.

Analysis
BPA chose the preferred plan for the following reasons:

- Lowest cost
- Essentially no environmental impact (existing site)
- Favorable Revenue/Cost ratio (2.75)
- Favorable economics under reduced load growth rate
- Short repayment period (6 years)

Energization Date: **Fall 2003 (Preferred Alternative)**
Estimated Cost: **$9M**

G12. Olympic Peninsula Reinforcement (Paul-Shelton 500-kV line)

Background
The Olympic Peninsula area load is served from Olympia substation via 230-kV and 115-kV transmission. The major source to Olympia to serve these loads is the 500-kV transmission line from Paul substation. An outage of this 500-kV source to Olympia would result in a voltage collapse during extra heavy winter load conditions. A second 500-kV source is needed to solve the voltage collapse problem as early as 2003. A shunt capacitor group to be installed in 2003 will delay the need for this project until 2005. With this addition the Olympic Peninsula transmission system has reached the limit that can be supported by shunt capacitors. A total of 20 capacitor groups amounting to approximately 900 MVAR will have been installed.

In addition, a double-line outage of the 230-kV double-circuit line from Olympia to Shelton or a breaker failure at Olympia will result in a total loss of the Olympic Peninsula during normal winter load. The proposed reinforcement will solve both the N-1 and N-2 problems and reinforce the Olympic Peninsula region.

Limiting Outages Addressed
- Olympia 500/230-kV transformer
- Paul-Olympia 500-kV line
- Olympia-Shelton 230-kV double line
- Olympia 230-kV breaker failure

Benefit - Load Area Service
This project will prevent these outages from impacting service to the Olympic Peninsula by providing a second source of power to the Peninsula from Paul Substation. This project will also increase the load service capability to the Olympic Peninsula under non-outage conditions as well as mitigate or delay other system upgrades that would be needed in the future if this project were not built.

Business Case
This project provides the capacity to carry additional projected normal winter load in the Olympic Peninsula area in compliance with NERC/WECC Planning Standards for Category A-C outages. For the purpose of this analysis revenues are based on 1.8% load growth corresponding to 26 MW/year reaching a project limit of 338 MW in 2019. In the Table below, Alternative 1 is the proposed plan and Alternative 2 would involve moving the 500/230-kV transformer to Olympia (see below). Alternatives 1a-1c are sensitivity studies discussed under "Risk.".

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV	Rev/C	Repayment Years	In Service	Life
1	21.6	29.3	(7.8)	0.74	20	2006	2040
1a	35.7	35.5	0.2	1.00	20	2006	2040
1b	14.4	34.1	(19.7)	0.42	31	2006	2040
1c	21.6	32.7	(11.1)	0.66	22	2006	2040
2	21.6	27.2	(5.7)	0.79	19	2006	2040

Risk

The following table qualitatively addresses various risk factors. Three are identified for evaluation.

Factor	Risk	Factor	Risk
Cost	**See sensitivity 1c**	Delivery on time	Routine purchases
Siting/ROW	Existing site/ROW	Funding	Available
Load Growth	**See sensitivity 1b**	Discount Rate	**See sensitivity 1a**

Sensitivity 1a – This case determines what discount rate is needed to achieve a Revenue/Cost ratio of 1.0. This is achieved by a discount rate of 6.5%, giving an equivalent rate of return on investment of 6.5% over the 34 year life of the project.
Sensitivity 1b – In this case the load growth rate of 1.8% is cut in half to 0.9%. This reduces the Revenue/Cost ratio from 0.74 to 0.42 and extends the repayment period from 20 years to 31 years.
Sensitivity 1c – This case represents an increase in project cost of 10%. The Revenue/Cost ratio for this case dropped from 0.74 to 0.66 and the repayment period increased from 20 years to 22 years.

Project Description

- Build approximately 13.8 miles of 500-kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to the Shelton 500 kV yard. The line will be routed on the existing Olympia-Shelton right of way. Cut the Paul-Satsop 500 kV line at corridor intersection and connect the Paul end to new 500 kV line to Shelton.
- Remove Olympia-Shelton 115 kV line #1 from Olympia to Dayton Tap.
- Construct a 500 kV yard approximately 1 mile south of the existing Shelton substation, move Satsop 500/230 kV transformer to this location and tie it to Shelton 230 kV bus via 1 mile long 230 kV line.
- Build approximately 6 miles of new 230 kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to Olympia substation. Connect this new line to Satsop end of cut Paul-Satsop 500 kV line.

Alternatives Considered

2. Move Satsop 500/230 kV transformer to Olympia substation and terminate the Paul-Satsop 500 kV line at Olympia.
3. No build alternative
4. Non-transmission alternatives

Alternative #2

Alternative #2 listed above has approximately the same capital cost as alternative #1.

Do-Nothing Alternative (#3)

(a) The following information applies to voltage collapse for N-1 contingencies for extra heavy winter if the transmission system is not reinforced:

- A 2 year MTBF for N-1 Paul-Olympia 500 kV line with average outage duration of 2.5 hours.
- A 100 year MTBF each phase of the Olympia 500/230 transformer and a 4 week replacement time. This corresponds to a bank outage probability of:

  P(outage) = 1-(1-1/100)^3 = 0.030, and a
  MTBF = 1/0.030 = 34 years.

- The required load curtailment for either outage increases by 26 MW yearly starting in 2006.

Since the outage time is quite different for the two events the societal costs are estimated separately. Voltage collapse is assumed to occur when the demand exceeds capacity following the outage by more than 100 MW. Area load is restored to the capability of the remaining system within one hour. Using the same customer outage costs as with G10 the present worth societal costs of the N-1 line outage is $1 M and the N-1 bank outage is $5.65 M for a ten year period.

(b) The following information was used to estimate the probability of loss of load for N-2 contingencies if the transmission system is not reinforced:

- 9.3 year MTBF for N-2 outage of Olympia – Shelton 230 kV lines 3 and 4. It is further assumed that one line can be restored within one hour and the second line within 24 hours.
- 0.018 breaker failures/year for each of eight breakers at Olympia. It is assumed that full service is restored within one hour by moving the affected line over to the bus tie breaker. This corresponds to a bus outage probability of

  P(outage) = 1-(1-0.018)^8 = 0.14, and a
  MTBF = 1/0.14 = 7.4 years.

Again, the societal costs of the two events are treated separately. In each case it is assumed that the entire area load will be lost due to voltage collapse for the initial period of one hour. The estimated present worth societal costs are: $5.06 M for the two-line outage and $500 K for the breaker failure outages.

Overall then the estimated present worth societal cost for a ten year period of the do-nothing alternative is approximately $15.7 M. The present value savings of a ten-year delay in the project is expected to be greater considering deferred capital, financing and O&M costs.

Non-Transmission Alternatives (#4)
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and

Environmental Economics, Nov. 2001 available at
http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm.

These measures could cost-effectively defer the need under N-1 contingencies, although they can not address the N-2 problems. BPA will further consider non-transmission alternatives before proceeding with this project. Cost information is not available at this time to allow presentation of an economic analysis.

Analysis

BPA has selected a preferred transmission plan from the alternatives considered, but has elected to defer a decision on the project to allow time for further development of the non-transmission alternative (#5) and to consider public input before proceeding.

Of the transmission alternatives considered, the preferred plan is Alternative 1 because it outperforms the Olympia option for both N-2 critical outages for essentially the same present worth cost without O&M expenses included. O&M costs would be higher for the Olympia option based on the amount of extra equipment that would be needed at the Olympia substation. The Olympia option would require major 230 kV work at the Olympia substation, including expansion of the 230 kV yard. Land would also have to be purchased around the 500 kV yard for 230 kV line routing into the 230 kV bus. Some of the line routing into the 230 kV bus may not even be physically possible based on current line routing, tower and road locations, land needs and right-of-way widths. The Shelton option has 8 MW less losses than the Olympia option based on 1170 MW of load, which is equivalent to normal winter load in 2002-03. These losses will increase with increases in load. The Shelton option would leave the system better prepared for the future.

BPA will further consider non-transmission alternatives before proceeding with this project.

Energization Date: **Fall 2006**
Estimated Cost: **$23-26 M**

G13. Paul – Troutdale 500-kV Line

Background

The existing I-5 corridor transmission system is limited to:

- 2400 MW North of Allston by a double Paul – Allston 500-kV line outage
- 1650 MW South of Allston by the Allston – Keeler 500-kV line outage

With new generation projects proposed in the area, the existing system is not adequate to provide transmission service to most new generating projects on a firm basis, likely resulting in generation curtailments.

At present, the double Paul – Allston 500-kV line outage requires 2850 MW generation dropping and opening of both Chehalis – Longview 230-kV line that run in parallel to the Paul – Allston line. This sectionalizing removes the northern feed into Portland metro area, resulting in load service only from the east side through Ostrander. Sectionalizing greatly reduces reactive margins in the system, which will become a limiting factor as load grows in Portland area. Sectionalizing was also shown to degrade transient stability performance.

Currently, the Allston – Keeler 500-kV line outage requires generation dropping up to 2850 MW to prevent thermal overloads. Historic data indicates that there were 19 line outages in the past 16 years, mostly cased either by lightning hits or trees. It is very desirable to reduce generation dropping amount for a single contingency since these are more frequent than multi-contingency outages.

This project is being taken through the WECC Regional Planning process.

Limiting Outages Addressed

Paul – Allston 500-kV double line
Allston – Keeler 500-kV line
Keeler – Pearl 500-kV line
Keeler breaker failure

Benefits

Table 1. Generation projects proposed in the area affecting transmission needs:

Project	Capacity	Energization	North of Allston	South of Allston
Napavine	600	11/1/03	More stress	More stress
Grays Harbor I	630	6/1/03	More stress	More stress
Longview – Enron	300	7/1/03	Less stress	More stress
Mint Farm	280	5/1/03	Less stress	More stress
Summit	530	11/1/03	Less stress	More stress
Big Hanaford	250	1/1/02	More stress	More stress
Port Westward	650	12/31/03	Less stress	More stress
Centralia efficiency	+ 70	Done	More stress	More stress
Grays Harbor II	630	11/1/04	More stress	More stress

It is evident that new generation will greatly increase stress the constrained I-5 paths. The existing system is not adequate to provide transmission service to most generating projects on firm basis, very likely resulting in generation curtailments. The new 500-kV line is expected to provide firm transmission rights for the proposed projects in the area.

A. Transfer Increase

It is expected that South of Allston limit will increase from 1650 MW to 2,700 – 2,900 MW. The new line will eliminate or greatly reduce the need for generation dropping for N-1 outages and allow time to ramp down generation. Upgrades of parallel 115-kV and 230-kV lines may be required to get the full capacity.

B. Load Service in Winter Conditions

Studies are under way.

Business Case

This project is driven by requests for long-term firm transmission by new generation and imports. Parties requesting transmission would be expected to fund the upgrade consistent with FERC policy.

Risk

The risk associated with this project is small because the generators will be expected to finance the transmission investment and/or commit to long-term transmission service.

Project Description

At present time, the plan of service is not fully defined. Two conceptual options have been considered and studied for electrical performance. Alternative #1 includes a 500-kV line from near Longview to Troutdale, and alternative #2 is a 500-kV line from near Longview to Pearl.

Analysis

No preferred alternative is proposed at this time. The project will be returned to the Technical Review Committee for consideration in 2003 following the WECC Regional Planning Process.

Energization Date: **Fall 2005**
Estimated Cost: **$117-155 M**

G14. North of John Day/Portland Area Reinforcement – (Loop the Hanford-Ostrander 500-kV line into Big Eddy)

Background

The proposed new generation additions around the McNary area along with the new McNary-John Day 500-kV line will increase the stress across the North of John Day and the flow between John Day and Big Eddy. This project will relieve some of the North of John Day constraint and reinforce the transmission between John Day and Big Eddy. In addition, this project will also reinforce the bulk load serving capability into the greater Portland area. During abnormal cold weather, an outage of the Bid Eddy-Ostrander 500-kV line results in voltage collapse in the Portland area. This Project will in effect create a second Big Eddy – Ostrander 500-kV line and increase the load serving capability to the Portland area.

Limiting Outages Addressed

Ashe-Marion/Slatt-Buckley 500-kV double line loss (summer)
John Day-Big Eddy 500-kV double line loss (summer)
Slatt 500-kV breaker failures (summer)
Big Eddy-Ostrander 500-kV line (winter)
Pearl 500-kV breaker failures (winter)

Benefit – Congestion Relief and Load Area Support

This project will increase the North of John Day capability by approximately 250-300 MW and increase the capability between John Day and Big Eddy by approximately 600-700 MW. This project also reinforces the bulk grid to serve greater Portland area load and eliminate the need for building second Big Eddy-Ostrander 500-kV line.

Business Case

The primary drivers of this project is North to South network transfers and provide additional network capacity for service to the Portland area load. The estimated cost recovery of this project at current rates and for the alternatives considered is over 35 years. In view of the long payback period lower cost alternatives or deferral will be considered.

Risk

The benefit ascribed to this project for the Portland area load is related to the timing of the Paul – Troutdale project which in part serves this need. The portion of benefits ascribed to intertie support will be beneficial at the time the project goes into service but is not sufficient alone to ensure full cost recovery. Risk that costs will not be recovered for this project as proposed at this point is high.

Project Description

- This project consists of constructing approximately 16.5 miles of 500-kV double circuit line to the Columbia River crossing and approximately 18 miles of single circuit 500-kV line to Big Eddy and 2 miles of line to John Day.

- Develop a new 500-kV switching station next to the existing Hanford (Wautoma) – Ostrander 500-kV line and loop in the Hanford-Ostrander line into the new switching station.
- Add terminals at Big Eddy and John Day to terminate the new lines.

Preliminary Alternatives

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit.

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit and building a third 20-mile single-circuit 500-kV line between John Day and Big Eddy.

Analysis
No preferred alternative is proposed at this time. The project may be returned to the Technical Review Committee for consideration in 2003 following further analysis.

Energization Date: Spring 2006
Estimated Cost: $70-90M

Appendix D - Economic Analysis

The analysis used for projects G10 and G12 was conducted using Excel spreadsheet calculations. The following indicators of economic performance were computed:

- Repayment time (years from in service date)
- Net Present Value
- Benefit to Cost Ratio

The basic economic assumptions used were as follows:

Discount Rate		9.00%
Inflation Rate		2.64%
BPA Financing Rate		6.75%
O&M Escalation		0.00%
BPA Rate Escalation		0.00%
O&M Actual		2.64%
BPA Rate Actual		2.64%

The high discount rate of 9% favors projects with a faster payback period. A lower discount rate would increase benefit/cost ratio for projects G10 and G12. The treasury borrowing rate of 6.75% represents recent historical BPA borrowing.

Net Present Value and Benefit to Cost were computed using a substation equipment service life of 34 years[1] since both projects G10 and G12 have major substation components.

Capital cost expenditures were distributed over the expected year of obligation over the construction period.

BPA transmission revenues were reckoned at the rate of $1.013 $/kW-mo (12.156 $/kW-year).

Projects G10 and G12 assume that 75% of the load increase is transmission revenue producing. Assuming 50% revenue producing reduces the benefit to cost ratios by about 1/3.

Typical operations and maintenance costs are used.[1]

[1] Annual Financial Requirements for Bonneville Power Administration Transmission System and revised Operation and Maintenance Tables, Larry Davidson, March 31, 2000.

Clarifications and Editorial Changes

Cover Letter
Page 1, paragraph 3.
Changed "BPA's" to read "BPA"

Report
Page 4
Inserted the following bullet to address G11.

> "Project G11 (South Seattle Transformer) is not addressed at this time and will be submitted for future ITRC review."

Appendix A
Replaced Mike Ryan's name with Richard Goddard (PGE)

Appendix B
Replace note asterisks with numbering
Added Note 3 "To be submitted for future ITRC review" applicable to G11, G13 and G14.

Appendix C – G10
Page C-2, Business Case
Improve flow of first sentence to read as follows:

> "This project provides the capacity to carry additional Portland area load increasing at the rate of 75 MW per year from 2004 though 2007."

Page C-2, Risk Factors
Darken borders in table at bottom of page to distinguish two groupings of Factor/Risk. Same for table under project G12.

Page C-3
Insert the following paragraph after section "Alternatives Considered"

> **"Alternatives #2 and #3**
> Alternatives #2 and #3 listed above have capital costs of $24.5 M and #36 M, respectively as compared to $9 M for alternative 1."

Page C-3, Do Nothing Alternative (#4), second paragraph
In the second sentence replace the words "remaining capability" with "outage limit" to read as follows:

> "Assuming that load is curtailed to the outage limit for a period of one week ..."

Page C-4
Change title of last section from "Decision" to "Analysis." Same change for projects G12, G13 and G14. The reason is to not imply a decision ahead of the NEPA process completion.

Appendix C – G12
Page C-6
Insert the following section after section "Alternatives Considered"

> **"Alternative #2**
> Alternative #2 listed above has approximately the same capital cost as alternative #1."

Appendix C – G13
Page C-10, strengthen wording in first paragraph
Original wording:

> "It is evident that new generation will greatly increase stress the constrained I-5 paths. The existing system is not adequate to provide transmission service to most generating projects on firm basis, very likely resulting in generation curtailments. The new 500-kV line is expected to provide firm transmission rights for the proposed projects in the area."

Revised wording:

> "It is evident that new generation will greatly increase stress on the constrained I-5 paths. The existing system is not adequate to provide transmission service to most generating projects on a firm basis, and with several plants under construction curtailments can be expected without this project. The new 500-kV line is expected to provide firm transmission rights for the proposed projects in the area."

Page C-10, improve wording of second sentence in first second
Original wording:

> "The new line will eliminate or greatly reduce the need for generation dropping for N-1 outages. The time to thermal overload will allow to ramp down generation of dropping."

Revised Wording

> "The new line will eliminate or greatly reduce the need for generation dropping for N-1 outages and allow time to ramp down generation."

Appendix C – G13
Page C-12, second bullet, improve wording
Original wording

> "Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit and build a third 20miles of single circuit 500-kV line between John Day and Big Eddy"

Revised wording

"Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit and building a third 20-mile single-circuit 500-kV line between John Day and Big Eddy."

Appendix E

Remove this appendix since the cost figures are now quoted in the new section added on page C-3. Remove reference to Appendix E in the report table of contents.

Wright, April E - KFF-2

From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Thursday, August 08, 2002 10:11 AM
To: 'Martinsen, John'; 'Morris, Ken'; 'Juj, Hardev'; 'Leland, John'; 'Waples, Scott'; 'Groce, Ed'; 'Eden, Jim'; 'Robinett, Wayman'; 'Schellberg, Ron'; Stadler, Larry W - TOP-PPO2-2; Horvath, Julius G - TOP-PPO2-2; Rodrigues, Melvin - TOP-PPO2-2; 'Johnson, Don'; 'Seabrook, Joe'
Cc: Regalado, Ann-Marie - TOM-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2; Silverstein, Brian L - TOP-PPO2-2
Subject: ITRC Report Conference Call

ITRC Participants

At the request of Wayman Robinett I have scheduled a conference call Monday August 12, 2002 from 10 AM to Noon PDT to discuss any matters coming out of a conference call that he has arranged for tomorrow among some of the participants. It is my understanding that two requests are: (1) to include a separate section relating to projects that were approved last year; and (2) interest by the participants in the detailed economic analysis spreadsheet.

The Excel economic analysis is attached for you and we would be happy an answer any questions about this during the Monday conference call or at any time. The BPAT benefit analysis is <u>based on new revenues</u> from load growth in the respective areas (75 MW/year up to an increase of 300 MW in the Portland area for G10, and 26 MW/year limiting up to an increase of 338 MW in the Olympic Penninsula for G12).

I will start to work on a summary section in the main report addressing status information on projects approved last year.

For the Monday conference call, BPA folks will meet in Room 201 so as to keep the bridge positions open for outside callers.

The phone bridge information for outside participants is:

Call 360-418-8001
Passcode: 6672#

If you have trouble connecting please call Ann my secretary at 360-619-6641 or the phone office at 360-418-8888. If you are unable to call in at the arranged time, please let me know and I can arrange a separate time for you.

Thanks for your participation. Signature pages have been received for 6 of the 8 signers. We look forward to completing this assignment.

Bill Mittelstadt

Economic Analysis
G10-12 7~18~...

William A Mittelstadt
(E-mail)...

Wright, April E - KFF-2

From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Monday, August 12, 2002 8:27 AM
To: Mittelstadt, Bill - TOM-PPO2-2; 'Martinsen, John'; 'Morris, Ken'; 'Juj, Hardev'; 'Leland, John'; 'Waples, Scott'; 'Groce, Ed'; 'Eden, Jim'; 'Robinett, Wayman'; 'Schellberg, Ron'; Stadler, Larry W - TOP-PPO2-2; Horvath, Julius G - TOP-PPO2-2; Rodrigues, Melvin - TOP-PPO2-2; 'Johnson, Don'; 'Seabrook, Joe'
Cc: Regalado, Ann-Marie - TOM-PPO2-2; Silverstein, Brian L - TOP-PPO2-2
Subject: RE: ITRC Report Conference Call

Attached is a writup summarizing the status of the G1-9 projects as requested by Wayman to be included in the report for discussion at our conference call.

Bill

Projects Reviewed in 2001.doc

Nilliam A Mittelstadt (E-mail)...

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Thursday, August 08, 2002 10:11 AM
To: 'Martinsen, John'; 'Morris, Ken'; 'Juj, Hardev'; 'Leland, John'; 'Waples, Scott'; 'Groce, Ed'; 'Eden, Jim'; 'Robinett, Wayman'; 'Schellberg, Ron'; Stadler, Larry W - TOP-PPO2-2; Horvath, Julius G - TOP-PPO2-2; Rodrigues, Melvin - TOP-PPO2-2; 'Johnson, Don'; 'Seabrook, Joe'
Cc: Regalado, Ann-Marie - TOM-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2; Silverstein, Brian L - TOP-PPO2-2
Subject: ITRC Report Conference Call

ITRC Participants

At the request of Wayman Robinett I have scheduled a conference call Monday August 12, 2002 from 10 AM to Noon PDT to discuss any matters coming out of a conference call that he has arranged for tomorrow among some of the participants. It is my understanding that two requests are: (1) to include a separate section relating to projects that were approved last year; and (2) interest by the participants in the detailed economic analysis spreadsheet.

The Excel economic analysis is attached for you and we would be happy an answer any questions about this during the Monday conference call or at any time. The BPAT benefit analysis is based on new revenues from load growth in the respective areas (75 MW/year up to an increase of 300 MW in the Portland area for G10, and 26 MW/year limiting up to an increase of 338 MW in the Olympic Penninsula for G12).

I will start to work on a summary section in the main report addressing status information on projects approved last year.

For the Monday conference call, BPA folks will meet in Room 201 so as to keep the bridge positions open for outside callers.

The phone bridge information for outside participants is:

Call 360-418-8001
Passcode: 6672#

If you have trouble connecting please call Ann my secretary at 360-619-6641 or the phone office at 360-418-8888. If you are unable to call in at the arranged time, please let me know and I can arrange a separate time for you.

Thanks for your participation. Signature pages have been received for 6 of the 8 signers. We look forward to completing this assignment.

Bill Mittelstadt

<< File: Economic Analysis G10-12 7~18~02.xls >>

<< File: William A Mittelstadt (E-mail).vcf >>

3. Projects Reviewed in 2001

Projects G1-G9 reviewed in 2001 remain in the construction program but in some cases with revised energization dates, or subject to commitments from proposed generation plants. A brief status statement follows on each of these projects;

G1 Puget Sound Area Additions (Kangley – Echo Lake 500 kV Line)
The energization date for this project has set back one year to Fall 2003 to allow a full analysis of alternatives through the environmental process. The Snoking 500/230 kV transformer energization has also been delayed by one year to Fall 2003.

G2 North of Hanford (Schultz – Wautoma 500 kV Line and Wautoma Substation)
This project is proceeding forward on the Fall 2004 schedule with no change in status.

G3 McNary – John Day 500 kV Line
This project is proceeding forward on the Fall 2004 schedule with financial commitments having been received from generation projects for preliminary design and environmental work.

G4 Lower Monumental – Starbuck 500 kV Line
Need for this project is presently uncertain due to delay of the Starbuck generation project. Continuation of this project will depend on resumed development of this site and agreements for financing of the transmission project.

G5 Smiths Harbor – McNary 500 kV Line
Work is proceeding on plans for construction of the substation at Smiths Harbor based on commitments from the Smiths Harbor generation project. Need for the transmission project depends on plans to move forward with the Starbuck generation project or other generation in the area.

G6 Schultz Series Capacitors
This project is proceeding ahead for completion in Fall 2003 per the original schedule.

G7 Celilo Modernization
Work is proceeding on this project with the expected energization revised from Fall 2003 to Summer 2004.

G8 Monroe – Echo Lake 500 kV Line
Non-transmission solutions are being reviewed by BPA as possible alternatives for this project scheduled for Fall 2005.

G9 Bell – Coulee 500 kV Line
This project is on schedule for Fall 2004 energization as reported in last year's report. Since that time, agreement has been reached on additional Phase 1 supporting facilities for service in the Spokane and Lewiston areas. Many of these facilities were included on the list of potential Phase 2 projects in the 2001 Infrastructure Technical Review Committee Report. These facilities, to be constructed by Avista, include the following:

Benewah-Shawnee 230 kV
Dry Creek 230 kV switching station
Beacon-Rathdrum double circuit 230 kV
Increase operating limits on Hatwai-Lolo 230 kV
Increase operating limits on Hatwai-North Lewiston 230 kV
Increase operating limits on Dry Creek-North Lewiston 230 kV
230 kV shunt capacitors at Benewah (200 MVAR)
230 kV shunt capacitors at Dry Creek (200 MVAR)

These facilities are planned for energization by December 2006.

From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Tuesday, August 13, 2002 8:14 AM
To: 'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; 'Groce, Ed'; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; 'Kinney, Scott'; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO-DITT2; 'Waples, Scott'
Cc: Mittelstadt, Bill - TOM-PPO2-2
Subject: ITRC Meeting Announcement

The Columbia Room at the Portland Airport PDX Conference Center has been reserved for Tuesday August 20th to review new revisions to the ITRC report discussed by conference call yesterday and to review a committee drafted cover letter as requested by the group. The meeting will commence at 9 am and is exected to be completed by 2 pm. I am working on incorporating comments in the report and expect to have it out for distribution by Wednesday morning.

Bill Mittelstadt

William A Mittelstadt
(E-mail)...

Wright, April E - KFF-2

From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Tuesday, August 13, 2002 9:29 AM
To: 'Groce, Ed'
Cc: Mittelstadt, Bill - TOM-PPO2-2; Lahmann, Bob - TM-DITT2
Subject: Marketer Funding of Transmission

Ed

I talked yesterday with Bob Lahmann, (360) 418-2092, about your question of managing risk in connection with marketer funding of transmission projects. Bob mentioned that as we enter construction a credit agreement is established involving BPA, the marketer funding the project and a bank upon which BPA can draw for construction of the facilities. In this arrangement the bank has the responsibility to pay the cost of construction in the event that the marketer defaults. There is a cost of this provision that depends on project and participant credit rating . If you have further question on this please feel free to contact Bob at the above number. This is more detail than we want to put in the report but it is important for you to know.

Bill

William A Mittelstadt
(E-mail)...

Wright, April E - KFF-2

From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Wednesday, August 14, 2002 8:22 AM
To: 'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; 'Groce, Ed'; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; 'Kinney, Scott'; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; 'Reese, Chris'; 'Robinett, Wayman'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO-DITT2; 'Waples, Scott'
Cc: Mittelstadt, Bill - TOM-PPO2-2
Subject: ITRC Report and Meeting

Per comments received during our Monday conference call I am redistributing the draft report in revisions format. Changes appear in files: "Report Draft" and "Appendix C." Additional pages are provided to Appendix D as an Excel workbook (print all worksheets).

As already noted it has been scheduled to convene the ITRC at the Portland Airport PDX conference center on Tuesday August 20 from 9 am to 2 pm to conclude any revisions to this report and conclude on the group drafted cover letter. We should plan on bringing closure to this years report at that Tuesday meeting and obtain signatures for the cover letter of those present.

If you have any further comments before that time please forward them to me.

Bill Mittelstadt

Villiam A Mittelstadt (E-mail)... | Report Draft 8~13.doc | Appendix A 7~31.doc | Appendix B 8~1.doc | Appendix C 8~13.doc | Appendix D.doc | Appendix Vorksheets 8~13~0

Upgrading the Capacity and Reliability of the BPA Transmission System

Report ~~of~~ to the Infrastructure Technical Review Committee

August 13, 2002

(with revisions from 8/12 call)

Table of Contents

Appendices

Please refer to the August 30, 2001 Infrastructure Review Committee report for information on the purpose of this Committee, terms of engagement and general system need. Also please refer to this report for system maps.

1. Executive Summary

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002). Problems with the transmission in the region are manifested in several ways:

- Chronic congestion existing on a number of transmission paths requires curtailment of both firm power deliveries and economy energy.
- Resolution of the Western energy crisis requires development of new generating resources. The vast majority of proposed Northwest resources cannot obtain firm transmission service, or be integrated, without additional bulk transmission.
- While power loads have been growing steadily at 1.8% annually and the use of the transmission system is up by over 2% annually, few bulk grid transmission lines were added in the past 15 years.
- It will take much longer to site and build transmission to deliver needed new generation than it will take to build and site the generation. New transmission is needed to meet ~~existing and future~~statutory, treaty and contractual obligations ~~in order to~~and comply with ~~recently adopted~~ national and regional standards that ensure a reliable power system[1].
- It is extremely difficult to meet obligations when facilities are removed from service to conduct normal maintenance or to construct new facilities.

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The Infrastructure Technical Review Committee (ITRC) was formed in 2001 at the behest of some of BPA's customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Once a year, the ITRC evaluates and prioritizes BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC), Operating Committee (OC) and the Northwest Regional Transmission Association (NRTA) Planning Committee (PC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not fund the work of the ITRC.

The committee was asked to report its initial recommendations by August 30, 2001 to enable BPA to install necessary system facilities as soon as possible.

This review is the second in an annual process to coincide with BPA's annual budget cycle. It covers four projects of BPA's infrastructure proposal. Review of additional projects will be conducted in subsequent years. There are several additional parallel efforts that provide for review of proposed transmission additions. This committee's analysis and recommendations will be shared and further analyzed in the following forums.

- Northwest Power Pool (NWPP) Transmission Planning Committee
- Western Electricity Coordinating Council (WECC) Regional Planning Group
- National Environmental Policy Act (NEPA) review for individual projects

During the first part of 2002 the committee met twice to review additional infrastructure proposal developed by BPA. While some of the proposals have been under development in previous forums with outside participation, other proposals were presented for the first time. The committee has reached the following conclusions and recommendations based on its review:

Projects Reviewed in 2001:

- Projects evaluated in previous years should continue on the revised timetable proposed by BPA. BPA should continue to reevaluate project need and timelines, particularly for projects driven by generation integration.
- In accordance with provisions in the January 15, 2002 guidelines[2] BPA provided a status report on projects that were approved last year. There were no significant changes in circumstances that necessitated any of these projects be returned to the committee for a full review.
- Section 3 provides a status report on these projects G1-G9.

Projects Reviewed in 2002:

There continues to be a compelling and immediate need to upgrade portions of the Northwest bulk transmission grid. Solutions proposed by BPA in coordination with others address the identified problems.

~~Projects evaluated in the first review should continue on the revised timetable proposed by BPA. BPA should continue to reevaluate project need and timelines, particularly for projects driven by generation integration.~~

- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G11 (South Seattle Transformer) is not addressed at this time and will be submitted for future ITRC review.
- Project G12 (Olympic Peninsula Reinforcement) is also important~~,~~. ~~although the~~The need date to prevent area problems for first contingency (N-1) outages is later than initially estimated based on the most recent load forecasts. Planned curtailment of area load is permitted under the NERC/WECC Planning Standards for the exposure to

double contingency (N-2) outages provided that system cascading does not result. Opportunities for non-transmission alternatives ~~should be~~are being pursued in parallel with the proposed transmission fix.

- Projects G13 (Paul – Troutdale 500-kV Line) and G14 (Hanford-Ostrander 500 kV loop-in) were examined on a preliminary basis. Project G13 is critical to integration of new generation in the I-5 corridor. BPA should complete details of the plan of service over the next 60 days and bring this through the WECC Regional Planning Process. In addition, coordination with PGE and PacifiCorp is required in relation to their respective transmission and generation expansion plans.
- The benefits of project G14 are not clear given proposed I5 generation development and potential higher costs to route around the Columbia Gorge Scenic Area. BPA should bring these projects forward to the committee for consideration in 2003 after further examination of alternatives and need.

Rate and Budgetary Impacts:
As started earlier, there continues to be a compelling and immediate need to upgrade portions of the Northwest bulk transmission grid and capital to meet that need.

- Figure 1 illustrates the historical and future trend transmission capital requirements forecasting by BPA over a ten-year planning horizon. Since this is well above BPA's remaining borrowing authority the need ~~need~~ still remains to increase BPA's borrowing authority for *transmission* by at least $1 billion in order to ensure that sufficient financial resources are available. ~~to accomplish transmission expansion over a ten-year planning horizon (see Figure 1, TBL Capital Projects Historical & Future, on page 7).~~
- BPA should continue to pursue and evaluate third party financing opportunities for major new transmission projects.
- Preliminary analysis has shown that increased transmission use will recover the cost of the proposed capital additions (details on the economic analysis are given in Appendix D). Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure 10 to 20 year firm transmission service contracts with appropriate credit provisions before proceeding with construction. ~~(Note: BPA's transmission investments are repaid by its transmission customers, not taxpayers.)~~
- Additional reinforcements by BPA and others are needed to maximize reliability and transfer capability from the proposals. Other Northwest utilities have planned transmission additions, and maximum benefits will be achieved through coordinated development.
- Future reviews should be conducted annually to evaluate and prioritize BPA proposed major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. In accordance with provisions in the January 15, 2002 guidelines[1] BPA provided a status report on projects that were approved last year. There were no significant changes in circumstances that necessitated any of these projects be returned to the committee for a full review.

2. Projects for 2002 Review

Project List

Project		Cost (loaded) ($M)	Energization Date	Capacity Added MW
Portland Area Additions	G10	9	2003	300
Olympic Peninsula Reinforcement	G12	26	2005	430
Total		35		

Project Drivers

	Load Service	Entitlement Return	Generation Integration	Transfers	Reliability	O&M Savings	BiOp
G10	x				x		
G12	x				x		

3. Projects Reviewed in 2001

Projects G1-G9 reviewed in 2001 remain in the construction program but in some cases with revised energization dates, or subject to commitments from proposed generation plants. A brief status statement follows on each of these projects;

G1 Puget Sound Area Additions (Kangley – Echo Lake 500 kV Line)
The energization date for this project has set back one year to Fall 2003 to allow a full analysis of alternatives through the environmental process. Based on approval by WECC the outage of the Raver – Echo Lake and Schultz – Echo Lake lines on common rights of way has been granted an exception from two-line outage requirements and reclassified as NERC/WECC Category D (exploratory). The Snoking 500/230 kV transformer energization has also been delayed by one year to Fall 2003.

G2 North of Hanford (Schultz – Wautoma 500 kV Line and Wautoma Substation)
This project is proceeding forward on the Fall 2004 schedule with no change in status.

G3 McNary – John Day 500 kV Line
This project is proceeding forward on the Fall 2004 schedule with financial commitments having been received from generation projects for preliminary design and environmental work.

G4 Lower Monumental – Starbuck 500 kV Line
Need for this project is presently uncertain due to delay of the Starbuck generation project. Continuation of this project will depend on resumed development of this site and agreements for financing of the transmission project.

G5 Smiths Harbor – McNary 500 kV Line

Work is proceeding on plans for construction of the substation at Smiths Harbor based on commitments from the Smiths Harbor generation project. Need for the transmission project depends on plans to move forward with the Starbuck generation project or other generation in the area.

G6 Schultz Series Capacitors
This project is proceeding ahead for completion in Fall 2003 per the original schedule.

G7 Celilo Modernization
Work is proceeding on this project with the expected energization revised from Fall 2003 to Summer 2004.

G8 Monroe – Echo Lake 500 kV Line
Non-transmission solutions are being reviewed by BPA as possible alternatives for this project scheduled for Fall 2005.

G9 Bell – Coulee 500 kV Line
This project, which is intended to increase capacity across the West of Hatwai bottleneck, is on schedule for Fall 2004 energization as reported in last year's report. Since that time, agreement has been reached on additional Phase 1 facilities (many of which were included on the list of potential Phase 2 projects in the 2001 Infrastructure Technical Review Committee Report), which are presently planned for energization between 2003 and 2007. These facilities, which will be constructed by the Avista Corporation, include the following projects:

- Benewah-Shawnee 230 kV Line.
- Dry Creek 230 kV Switching Station.
- Beacon-Rathdrum Double Circuit 230 kV Line.
- Increase operating limits on Hatwai-Lolo 230 kV Line.
- Increase operating limits on Hatwai-North Lewiston 230 kV Line.
- Increase operating limits on Dry Creek-North Lewiston 230 kV Line.
- Install 230 kV shunt capacitors at Benewah (200 MVAR).
- Install 230 kV shunt capacitors at Dry Creek (200 MVAR).

All of the facilities listed above will be taken through the WECC Regional Planning Process. Since the Bell-Coulee 500 kV line has already been through the process, it is expected that this will be an abbreviated process with comments only for the additional facilities. Any additions or changes to the above list of projects will be identified through the Regional Planning Process. The complete slate of Phase I facilities reinforcing the West of Hatwai Path including the Coulee – Bell 500 kV line will then be taken through the WECC Path Rating Process. Additional (West of Hatwai Phase II) facilities, which may be necessary in the Northern Idaho / Western Montana area will be identified in a follow up effort.

4. Glossary of Acronyms and Terms

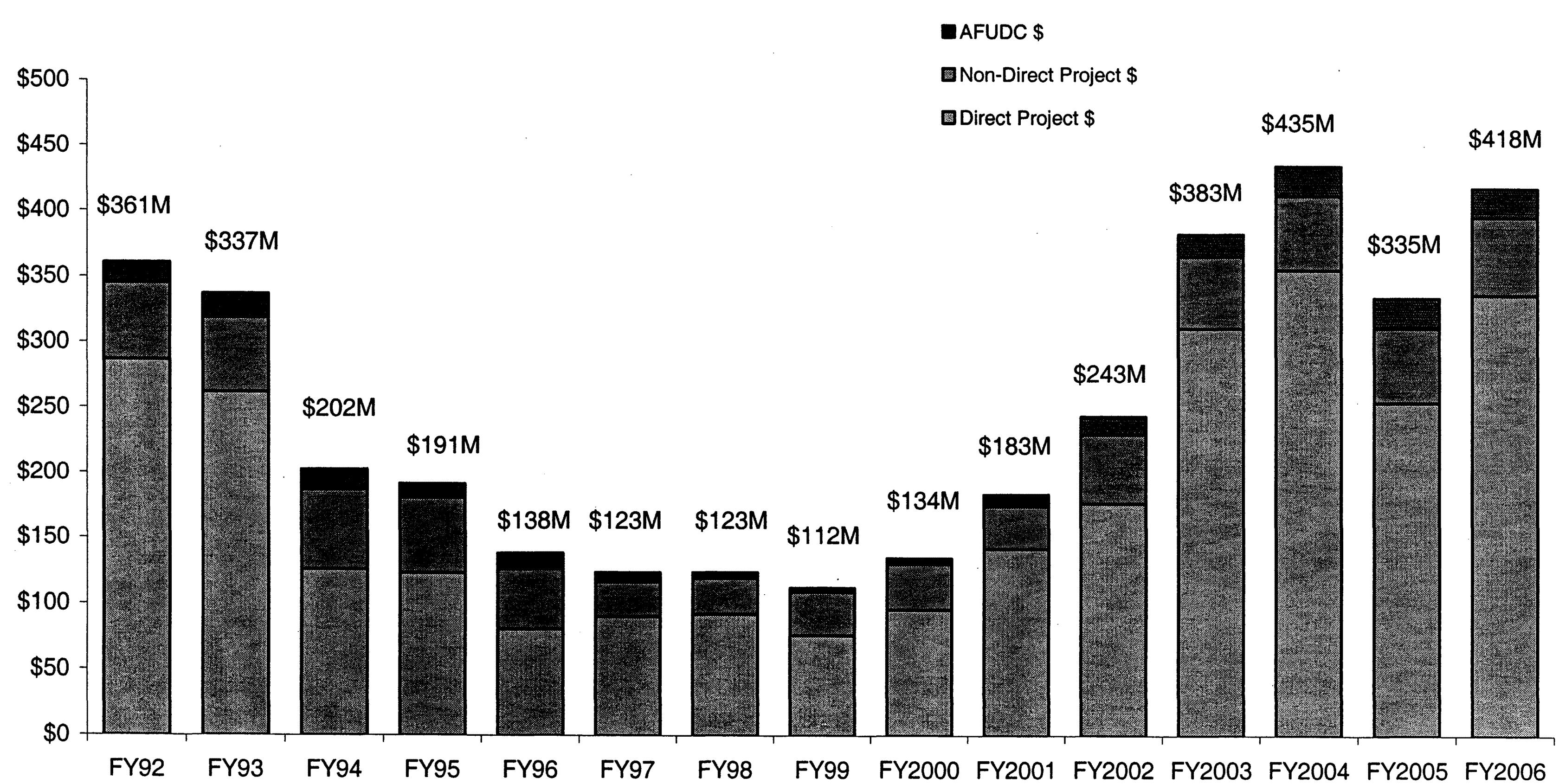
BiOp	Biological Opinion
MW	A unit of power. One MW would serve approximately 700 homes.
NRTA	Northwest Regional Transmission Association
NWPP	Northwest Power Pool
RTO	Regional Transmission Organization
WECC	Western Electricity Coordinating Council

Bulk Transmission – Transmission lines that serve as the backbone of the grid, typically operated at voltages of 230-kV and above.

5. References

[1] "NERC/WECC Planning Standards, Board of Trustees approved April 18, 2002.
[~~1~~2] "Annual BPA Transmission Infrastructure Review," January 15, 2002.

Figure 1. TBL Capital Projects Historical & Future Trend



Appendix A – Participants

Name		With	Phone	E-Mail	Note
Bayless	Rich	PACW	503-813-5739	rich.bayless@pacificorp.com	
Eden	Jim	PGE	503-464-7031	jim_eden@pgn.com	
Johnson	Don	PAC	503.813.5741	don.johnson@pacificorp.com	
Juj	Hardev	SCL	206-233-1551	hardev.juj@ci.seattle.wa.us	
Kinney	Scott	AVA	509.495.4494	skinney@avistacorp.com	
Leland	John	NWE	406.497.3383	John.Leland@northwestern.com	
Litchfield	Jim	Consultant	503 222-9480	lcg@europa.com	
Martinsen	John	SNOPUD	425.347.4327	jdmartinsen@snopud.com	
Morris	Ken	PAC	801.220.4277	ken.morris@pacificorp.com	
Reedy	Dana	NWPP	503.464.2806	dana.reedy@nwpp.org	
Robinett	Wayman	PSE	425.462.3144	wrobin@puget.com	
Rust	Jerry	NWPP	503-464-2807	jerry.rust@nwpp.org	
Ryan	Mike	PGE	503-464-8793	mike_ryan@pgn.com	
Schellberg	Ron	IPC	208-388-2455	rschellberg@idahopower.com	
Seabrook	Joe	PSE	425.462.3577	jseabr@puget.com	
Sidiropoulos	Mike	PAC		michael.sidiropoulos@pacificorp.com	
Waples	Scott	AVA	509.495.4462	scott.waples@avistacorp.com	

BPA Contacts					
Carter	Lawrence	BPAT	360.619.6674	ldcarter@bpa.gov	
Horvath	Julius	BPAT	360.619.6673	jghorvath@bpa.gov	
Kosterev	Dmitry	BPAT	360.619.6671	dnkosterev@bpa.gov	
Landauer	Marv	BPAT	360.619.6602	mlandauer@bpa.gov	
Mittelstadt	Bill	BPAT	360.619.6672	wmittelstadt@bpa.gov	
Rodrigues	Melvin	BPAT	360.619.6676	mtrodrigues@bpa.gov	
Silverstein	Brian	BPAT	360.619.6651	blsilverstein@bpa.gov	
Stadler	Larry	BPAT	360.619.6691	lwstadler@bpa.gov	
VanZandt	Vickie	BPAT	360.418.8459	vrvanzandt@bpa.gov	

Appendix B –Project Schedules

Project		Energization
Kangley - Echo Lake 500 kV line	G1	Fall 2003[1]
Schultz - Wautoma 500 kV line	G2	Fall 2004
McNary - John Day 500 kV line	G3	Fall 2004
Lo Monumental - Starbuck 500 kV line	G4	Fall 2004[2]
Smiths Harbor - McNary 500 kV line	G5	Fall 2004[2]
Schultz series capacitors	G6	Fall 2003
Celilo Modernization	G7	Summer 2004[1]
Monroe - Echo Lake 500 kV line	G8	Fall 2005
Bell - Coulee 500 kV line	G9	Fall 2004
Pearl Transformer	G10	Fall 2003
South Seattle Transformer	G11	Fall 2004[2,3]
Olympic Pennsula Reinforcement	G12	Fall 2006[1,2]
Paul - Troutdale 500 kV line	G13	Fall 2005[3]
Hanford - Ostrander loop-in	G14	Spring 2005[2,3]

Notes:
1 Denotes change from September, 2001 report
2 Energization may change depending on need.
3 To be submitted for future ITRC review.

Appendix C – Project Summaries

G10. Portland Area Additions (Pearl 500/230 kV Transformer)

Background

The Portland area is currently served by four 500/230 kV transformers: Troutdale on the east side, McLoughlin in SE Portland, Pearl in SW Portland and Keeler on the west side. This project is another phase of reinforcing the load serving capability from the bulk transmission system into the greater Portland area. Earlier reinforcements included adding a new 230 kV double-circuit line between Pearl and PGE's Sherwood substation.

Addition of the 2nd transformer at Pearl will require extension of both the 500 kV and the 230 kV buses. These extensions are within the existing Pearl substation.

Limiting Outages Addressed

Existing Pearl 500/230 kV Transformer

Benefit – Load Area Service

This project will increase the load carrying capability into the greater Portland area. Without this project it would be necessary to trip off load in the Portland area to relieve overloads during abnormal cold winter peaks for an outage of the existing Pearl transformer.

Business Case

This project provides the capacity to carry additional Portland area load increasing at the rate of 75 MW per year from 2004 though 2007. Beyond that date it will provide load serving benefit to the capacity of the bank following a suitable plan to address the Big Eddy – Ostrander 500 kV line outage. For the purpose of this analysis the benefit stream is limited to 300 MW for the period beyond 2007. In the Table below, Alternative 1 is the preferred plan. Alternatives 2-5 are described on the next page.

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV	Rev/C	Repayment Years	In Service	Life
1	30.8	11.2	19.6	2.75	6	2003	2037
2	30.8	32.6	(1.8)	0.95	14	2003	2037
3	30.8	54.4	(23.7)	0.57	25	2003	2037
1a (0.9%)	26.9	11.9	15.0	2.26	8	2003	2037

Risk Factors

The following table qualitatively addresses various risk factors:

Factor	Risk	Factor	Risk
Cost	Invoiced	Delivery on time	In inventory
Siting/ROW	Existing site	Funding	Available
Load Growth	See sensitivity 1a	Discount Rate	Not considered

The proposed site has space reserved for the transformer addition. Since this does not involve work outside the substation there are no environmental risks. The Revenue/Cost ratio remains favorable with half the of the projected load growth (1a). Accordingly, this is considered to be a very low risk project.

Project Description (Alternative 1)
This project adds a 2nd 500/230 kV transformer at the existing Pearl Substation. The new transformer will be 3 single-phase units (433 MVA each). The new bank will be equipped with a 9 step LTC and a tertiary for station service. One 500 kV breaker and one 230 kV breaker will be added. The 500 kV and 230 kV buses will be extended.

Alternatives Considered

2. Install a 500/230 kV transformer at PGE's Sherwood Substation. This location would be higher cost, require additional property and would be difficult to site. It was considered in the past, but the decision was made to increase the 230 kV capacity between Pearl and Sherwood.
3. Install a 500/230 kV transformer at McLoughlin Substation.
4. Curtail load in the event of a transformer outage (Do Nothing).
5. Non-transmission alternatives.

Alternatives #2 and #3
Alternatives 2 and 3 listed above have capital costs of $24.5 M and $36 M, respectively as compared to $9 M for alternative 1.

Do-Nothing Alternative (#4)
The "no build" alternative represents the risk of load interruption for a first contingency 500/230 transformer outage at any of the four following locations: Keeler; Pearl; McLoughlin; Troutdale. Load interrupted ranges from 75 MW in 2004 to 900 MW in 2015. Based on a single phase transformer outage failure rate of once per 100 years the outage mean time between failure (MTBF) is estimated as follows:

P(no outage) = (1-1/100)^(4 banks*3 transformers/bank)
P(no outage) = 0.886
P(outage) = 1-0.886 = 0.114
MTBF = 1/0.114 = 8.8 years

While the revenues for the do-nothing alternative can be assumed to be the same assuming load can be carried under the no-outage condition, the societal cost of a bank outage would be significant. Assuming that load is curtailed to the outage limit for a period of one week until a new transformer unit is installed the present worth societal cost over ten years of service is estimated to be about $4.9 M. This is calculated using the above MTBF estimate, the following load interruption cost figures inflated yearly by 2.64% and assuming the system exposure is 8 hours/day for two months/year.

Load Type	Composition	$/kWHr (2002)
Residential	50%	$1.66
Commercial	30%	$18.50
Industrial	20%	$27.56

Non-Transmission Alternatives (#5)
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and Environmental Economics, Nov. 2001 available at:

http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm.

Non-transmission alternatives can not be implemented in time to be considered a viable alternative to this project.

Analysis
BPA chose the preferred plan for the following reasons:

- Lowest cost
- Essentially no environmental impact (existing site)
- Favorable Revenue/Cost ratio (2.75)
- Favorable economics under reduced load growth rate
- Short repayment period (6 years)

Energization Date: **Fall 2003 (Preferred Alternative)**
Estimated Cost: **$9M**

G12. Olympic Peninsula Reinforcement (Paul-Shelton 500-kV line)

Background
The Olympic Peninsula area load is served from Olympia substation via 230-kV and 115-kV transmission. The major source to Olympia to serve these loads is the 500-kV transmission line from Paul substation. An outage of this 500-kV source to Olympia would result in a voltage collapse during extra heavy winter load conditions. A second 500-kV source is needed to solve the voltage collapse problem as early as 2003. A shunt capacitor group to be installed in 2003 will delay the need for this project until 2005. With this addition the Olympic Peninsula transmission system has reached the limit that can be supported by shunt capacitors. A total of 20 capacitor groups amounting to approximately 900 MVAR will have been installed.

In addition, a double-line outage of the 230-kV double-circuit line from Olympia to Shelton or a breaker failure at Olympia will result in a total loss of the Olympic Peninsula during normal winter load. The proposed reinforcement will solve both the N-1 and N-2 problems and reinforce the Olympic Peninsula region.

Limiting Outages Addressed
- Olympia 500/230-kV transformer
- Paul-Olympia 500-kV line
- Olympia-Shelton 230-kV double line
- Olympia 230-kV breaker failure

Benefit - Load Area Service
This project will prevent these outages from impacting service to the Olympic Peninsula by providing a second source of power to the Peninsula from Paul Substation. This project will also increase the load service capability to the Olympic Peninsula under non-outage conditions as well as mitigate or delay other system upgrades that would be needed in the future if this project were not built.

Business Case
This project provides the capacity to carry additional projected normal winter load in the Olympic Peninsula area in compliance with NERC/WECC Planning Standards for Category A-C outages. For the purpose of this analysis revenues are based on 1.8% load growth corresponding to 26 MW/year reaching a project limit of 338 MW in 2019. In the Table below, Alternative 1 is the proposed plan and Alternative 2 would involve moving the 500/230-kV transformer to Olympia (see below). Alternatives 1a-1c are sensitivity studies discussed under "Risk."

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV	Rev/C	Repayment Years	In Service	Life
1	21.6	29.3	(7.8)	0.74	20	2006	2040
1a	35.7	35.5	0.2	1.00	20	2006	2040
1b	14.4	34.1	(19.7)	0.42	31	2006	2040
1c	21.6	32.7	(11.1)	0.66	22	2006	2040
2	21.6	27.2	(5.7)	0.79	19	2006	2040

Risk
The following table qualitatively addresses various risk factors. Three are identified for evaluation.

Factor	Risk	Factor	Risk
Cost	**See sensitivity 1c**	Delivery on time	Routine purchases
Siting/ROW	Existing site/ROW	Funding	Available
Load Growth	**See sensitivity 1b**	Discount Rate	**See sensitivity 1a**

Sensitivity 1a – This case determines what discount rate is needed to achieve a Revenue/Cost ratio of 1.0. This is achieved by a discount rate of 6.5%, giving an equivalent rate of return on investment of 6.5% over the 34 year life of the project.
Sensitivity 1b – In this case the load growth rate of 1.8% is cut in half to 0.9%. This reduces the Revenue/Cost ratio from 0.74 to 0.42 and extends the repayment period from 20 years to 31 years.
Sensitivity 1c – This case represents an increase in project cost of 10%. The Revenue/Cost ratio for this case dropped from 0.74 to 0.66 and the repayment period increased from 20 years to 22 years.

Project Description

- Build approximately 13.8 miles of 500-kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to the Shelton 500 kV yard. The line will be routed on the existing Olympia-Shelton right of way. Cut the Paul-Satsop 500 kV line at corridor intersection and connect the Paul end to new 500 kV line to Shelton.
- Remove Olympia-Shelton 115 kV line #1 from Olympia to Dayton Tap.
- Construct a 500 kV yard approximately 1 mile south of the existing Shelton substation, move Satsop 500/230 kV transformer to this location and tie it to Shelton 230 kV bus via 1 mile long 230 kV line.
- Build approximately 6 miles of new 230 kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to Olympia substation. Connect this new line to Satsop end of cut Paul-Satsop 500 kV line.

Alternatives Considered

2. Move Satsop 500/230 kV transformer to Olympia substation and terminate the Paul-Satsop 500 kV line at Olympia.
3. No build alternative
4. Non-transmission alternatives

Alternative #2
Alternative #2 listed above has approximately the same capital cost as alternative #1.

Do-Nothing Alternative (#3)

(a) The following information applies to voltage collapse for N-1 contingencies for extra heavy winter if the transmission system is not reinforced:

- A 2 year MTBF for N-1 Paul-Olympia 500 kV line with average outage duration of 2.5 hours.
- A 100 year MTBF each phase of the Olympia 500/230 transformer and a 4 week replacement time. This corresponds to a bank outage probability of:

  P(outage) = 1-(1-1/100)^3 = 0.030, and a
  MTBF = 1/0.030 = 34 years.

- The required load curtailment for either outage increases by 26 MW yearly starting in 2006.

Since the outage time is quite different for the two events the societal costs are estimated separately. Voltage collapse is assumed to occur when the demand exceeds capacity following the outage by more than 100 MW. Area load is restored to the capability of the remaining system within one hour. Using the same customer outage costs as with G10 the present worth societal costs of the N-1 line outage is $1 M and the N-1 bank outage is $5.65 M for a ten year period.

(b) The following information was used to estimate the probability of loss of load for N-2 contingencies if the transmission system is not reinforced:

- 9.3 year MTBF for N-2 outage of Olympia – Shelton 230 kV lines 3 and 4. It is further assumed that one line can be restored within one hour and the second line within 24 hours.
- 0.018 breaker failures/year for each of eight breakers at Olympia. It is assumed that full service is restored within one hour by moving the affected line over to the bus tie breaker. This corresponds to a bus outage probability of

  P(outage) = 1-(1-0.018)^8 = 0.14, and a
  MTBF = 1/0.14 = 7.4 years.

Again, the societal costs of the two events are treated separately. In each case it is assumed that the entire area load will be lost due to voltage collapse for the initial period of one hour. The estimated present worth societal costs are: $5.06 M for the two-line outage and $500 K for the breaker failure outages.

Overall then the estimated present worth societal cost for a ten year period of the do-nothing alternative is approximately $15.7 M. The present value savings of a ten-year delay in the project is expected to be greater considering deferred capital, financing and O&M costs.

Non-Transmission Alternatives (#4)
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and

Environmental Economics, Nov. 2001 available at
http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm.

These measures could cost-effectively defer the need under N-1 contingencies, although they can not address the N-2 problems. BPA will further consider non-transmission alternatives before proceeding with this project. Cost information is not available at this time to allow presentation of an economic analysis.

Reliability Considerations

The NERC/WECC Planning Standards address planning requirements for the various contingencies applicable to this project. Planned loss of demand or curtailment of firm transfers is permitted for the case of the double line outage (N-2) and the stuck breaker but not for the single contingency outage (N-1). Cascading outages are not permitted. Cascading is "...the uncontrolled successive loss of system elements triggered by an incident at any location...and results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies."[1] To meet these requirements a solution must be in place not later than the time (1) the system is adversely impacted for single contingency outages or (2) cascading outages occur for the less probable breaker failure and double contingency outages. In the event that loss of demand or firm transfers are indicated than it is on a planned basis " to maintain the overall security of the interconnected transmission system." In the case of this project these contingencies will not result in cascading or impact the security of the overall system. However, the societal impact of these low likelihood events will continue to be examined as another indicator affecting project need date.

Analysis

BPA has selected a preferred transmission plan from the alternatives considered, but has elected to defer a decision on the project to allow time for further development of the non-transmission alternative (#5) and to consider public input before proceeding.

Of the transmission alternatives considered, the preferred plan is Alternative 1 because it outperforms the Olympia option for both N-2 critical outages for essentially the same present worth cost without O&M expenses included. O&M costs would be higher for the Olympia option based on the amount of extra equipment that would be needed at the Olympia substation. The Olympia option would require major 230 kV work at the Olympia substation, including expansion of the 230 kV yard. Land would also have to be purchased around the 500 kV yard for 230 kV line routing into the 230 kV bus. Some of the line routing into the 230 kV bus may not even be physically possible based on current line routing, tower and road locations, land needs and right-of-way widths. The Shelton option has 8 MW less losses than the Olympia option based on 1170 MW of load, which is equivalent to normal winter load in 2002-03. These losses will increase with increases in load. The Shelton option would leave the system better prepared for the future.

BPA will further consider non-transmission alternatives before proceeding with this project.

Energization Date: **Fall 2006**
Estimated Cost: **$23-26 M**

G13. Paul – Troutdale 500-kV Line

Background
The existing I-5 corridor transmission system is limited to:
- 2400 MW North of Allston by a double Paul – Allston 500-kV line outage
- 1650 MW South of Allston by the Allston – Keeler 500-kV line outage

With new generation projects proposed in the area, the existing system is not adequate to provide transmission service to most new generating projects on a firm basis, likely resulting in generation curtailments.

At present, the double Paul – Allston 500-kV line outage requires 2850 MW generation dropping and opening of both Chehalis – Longview 230-kV line that run in parallel to the Paul – Allston line. This sectionalizing removes the northern feed into Portland metro area, resulting in load service only from the east side through Ostrander. Sectionalizing greatly reduces reactive margins in the system, which will become a limiting factor as load grows in Portland area. Sectionalizing was also shown to degrade transient stability performance.

Currently, the Allston – Keeler 500-kV line outage requires generation dropping up to 2850 MW to prevent thermal overloads. Historic data indicates that there were 19 line outages in the past 16 years, mostly cased either by lightning hits or trees. It is very desirable to reduce generation dropping amount for a single contingency since these are more frequent than multi-contingency outages.

This project is being taken through the WECC Regional Planning process.

Limiting Outages Addressed
Paul – Allston 500-kV double line
Allston – Keeler 500-kV line
Keeler – Pearl 500-kV line
Keeler breaker failure

Benefits

Table 1. Generation projects proposed in the area affecting transmission needs:

Project	Capacity	Energization	North of Allston	South of Allston
Napavine	600	11/1/03	More stress	More stress
Grays Harbor I	630	6/1/03	More stress	More stress
Longview – Enron	300	7/1/03	Less stress	More stress
Mint Farm	280	5/1/03	Less stress	More stress
Summit	530	11/1/03	Less stress	More stress
Big Hanaford	250	1/1/02	More stress	More stress
Port Westward	650	12/31/03	Less stress	More stress
Centralia efficiency	+ 70	Done	More stress	More stress
Grays Harbor II	630	11/1/04	More stress	More stress

It is evident that new generation will greatly increase stress the constrained I-5 paths. The existing system is not adequate to provide transmission service to most generating projects on firm basis, very likely resulting in generation curtailments. The new 500-kV line is expected to provide firm transmission rights for the proposed projects in the area.

A. Transfer Increase

It is expected that South of Allston limit will increase from 1650 MW to 2,700 – 2,900 MW. The new line will eliminate or greatly reduce the need for generation dropping for N-1 outages and allow time to ramp down generation. Upgrades of parallel 115-kV and 230-kV lines may be required to get the full capacity.

B. Load Service in Winter Conditions

Studies are under way.

Business Case
This project is driven by requests for long-term firm transmission by new generation and imports. Parties requesting transmission would be expected to fund the upgrade consistent with FERC policy.

Risk
The risk associated with this project is small because the generators will be expected to finance the transmission investment and/or commit to long-term transmission service.

Project Description
At present time, the plan of service is not fully defined. Two conceptual options have been considered and studied for electrical performance. Alternative #1 includes a 500-kV line from near Longview to Troutdale, and alternative #2 is a 500-kV line from near Longview to Pearl.

Analysis
No preferred alternative is proposed at this time. The project will be returned to the Technical Review Committee for consideration in 2003 following the WECC Regional Planning Process.

Energization Date: **Fall 2005**
Estimated Cost: **$117-155 M**

G14. North of John Day/Portland Area Reinforcement – (Loop the Hanford-Ostrander 500-kV line into Big Eddy)

Background

The proposed new generation additions around the McNary area along with the new McNary-John Day 500-kV line will increase the stress across the North of John Day and the flow between John Day and Big Eddy. This project will relieve some of the North of John Day constraint and reinforce the transmission between John Day and Big Eddy. In addition, this project will also reinforce the bulk load serving capability into the greater Portland area. During abnormal cold weather, an outage of the Bid Eddy-Ostrander 500-kV line results in voltage collapse in the Portland area. This Project will in effect create a second Big Eddy – Ostrander 500-kV line and increase the load serving capability to the Portland area.

Limiting Outages Addressed

Ashe-Marion/Slatt-Buckley 500-kV double line loss (summer)
John Day-Big Eddy 500-kV double line loss (summer)
Slatt 500-kV breaker failures (summer)
Big Eddy-Ostrander 500-kV line (winter)
Pearl 500-kV breaker failures (winter)

Benefit – Congestion Relief and Load Area Support

This project will increase the North of John Day capability by approximately 250-300 MW and increase the capability between John Day and Big Eddy by approximately 600-700 MW. This project also reinforces the bulk grid to serve greater Portland area load and eliminate the need for building second Big Eddy-Ostrander 500-kV line.

Business Case

The primary drivers of this project is North to South network transfers and provide additional network capacity for service to the Portland area load. The estimated cost recovery of this project at current rates and for the alternatives considered is over 35 years. In view of the long payback period lower cost alternatives or deferral will be considered.

Risk

The benefit ascribed to this project for the Portland area load is related to the timing of the Paul – Troutdale project which in part serves this need. The portion of benefits ascribed to intertie support will be beneficial at the time the project goes into service but is not sufficient alone to ensure full cost recovery. Risk that costs will not be recovered for this project as proposed at this point is high.

Project Description

- This project consists of constructing approximately 16.5 miles of 500-kV double circuit line to the Columbia River crossing and approximately 18 miles of single circuit 500-kV line to Big Eddy and 2 miles of line to John Day.

- Develop a new 500-kV switching station next to the existing Hanford (Wautoma) – Ostrander 500-kV line and loop in the Hanford-Ostrander line into the new switching station.
- Add terminals at Big Eddy and John Day to terminate the new lines.

Preliminary Alternatives

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit.

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit and building a third 20-mile single-circuit 500-kV line between John Day and Big Eddy.

Analysis
No preferred alternative is proposed at this time. The project may be returned to the Technical Review Committee for consideration in 2003 following further analysis.

Energization Date: Spring 2006
Estimated Cost: $70-90M

Appendix D - Economic Analysis

The analysis used for projects G10 and G12 was conducted using Excel spreadsheet calculations. The following indicators of economic performance were computed:

- Repayment time (years from in service date)
- Net Present Value
- Benefit to Cost Ratio

The basic economic assumptions used were as follows:

Discount Rate		9.00%
Inflation Rate		2.64%
BPA Financing Rate		6.75%
O&M Escalation		0.00%
BPA Rate Escalation		0.00%
O&M Actual		2.64%
BPA Rate Actual		2.64%

The high discount rate of 9% favors projects with a faster payback period. A lower discount rate would increase benefit/cost ratio for projects G10 and G12. The treasury borrowing rate of 6.75% represents recent historical BPA borrowing.

Net Present Value and Benefit to Cost were computed using a substation equipment service life of 34 years[1] since both projects G10 and G12 have major substation components.

Capital cost expenditures were distributed over the expected year of obligation over the construction period.

BPA transmission revenues were reckoned at the rate of $1.013 $/kW-mo (12.156 $/kW-year).

Projects G10 and G12 assume that 75% of the load increase is transmission revenue producing. Assuming 50% revenue producing reduces the benefit to cost ratios by about 1/3.

Typical operations and maintenance costs are used.[1]

[1] Annual Financial Requirements for Bonneville Power Administration Transmission System and revised Operation and Maintenance Tables, Larry Davidson, March 31, 2000.

Tabale D-1. Cost Stream and Economic Parameters

Discount Rate		9.00%	(Not used for payback studies)			
Inflation Rate		2.64%				
BPA Financing Rate		6.75%				
O&M Escalation		0.00%			$/kw-mo.	$/kw-yr.
BPA Rate Escalation		0.00%		Rate 1	1.013	12.156
O&M Actual		2.64%		Rate 2	1.013	12.156
BPA Rate Actual		2.64%		Rate 3	1.013	12.156

Project G10		Repayment	B/C	In	Cost				Distributed Capital Cost							
Larry Stadler		(years)		Service	(loaded)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Alternative					($M)	($M)	($M)	($M)	($M)	($M)	($M)	($M)	($M)	($M)	($M)	($M)
Pearl Transformer	1	6	2.7	2003	9	1	8									
Sherwood Transformer	2	14	0.9	2003	25	2	23									
McLoughlin Transformer	3	25	0.6	2003	36	2	34									
	1a	8	2.3	2003	9	1	8									

Project G12		Repayment	B/C		Cost				Distributed Capital Cost							
Julius Horvath		(years)			(loaded)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Alternative					($M)	($M)	($M)	($M)	($M)	($M)	($M)	($M)	($M)	($M)	($M)	($M)
Shelton Transformer	1	20	0.7	2006	26					24.1	1.6					
Olympia Transformer	2	19	0.8	2006	26					21.3			1.6			3
6.5% discount rate	1a	20	0.7	2006	26					24.1	1.6					
0.09% load growth	1b	31	0.4	2006	26					24.1	1.6					
10% cost increase	1c	22	0.7	2006	28					26.51	1.76					

Wright, April E - KFF-2

From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Friday, August 16, 2002 8:32 AM
To: 'Phillips, John M -GEN04W'
Cc: Horvath, Julius G - TOP-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2
Subject: RE: ITRC Report and Meeting

William A Mittelstadt
(E-mail)...

John

In the second comment, are you referring to footnote d?

"Depending on system design and expected sysetm impacts, the controlled interruption of electric supply to customerse (load shedding), the planned removal from service of certain generators, or the curtailment of contracted firm (non-recallable reserved) electric power transfer may be necessary to maintain the oerall security opf the interconnected transmission systems."

Bill

-----Original Message-----
From: Phillips, John M -GEN04W [mailto:john.phillips@pse.com]
Sent: Thursday, August 15, 2002 4:39 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Cc: Reese, Chris; Robinett, Wayman; RODRIGUES, MELVIN; Seabrook, Joe
Subject: RE: ITRC Report and Meeting

Bill,

PSE had two comments.

We still aren't comfortable with justification for the $1 billion figure in the report. However, if BPA feels it needs to remain in the report and the committee disagrees then it can be addressed in the cover letter.

The second item is the verbiage added to the report and appendix C regarding G-12. Justification for delaying the project are based the NERC/WECC guidelines allowing for "planned" loss of load for a level "C" outages. Per the guidelines the loss of load also needs to be controlled. Does BPA currently have in place controls to prevent a voltage collapse during heavy winter loading? If not, a proposal, such as a RAS, should be added.

Thanks,
John

Note E-Mail Address Change: john.phillips@pse.com

John Phillips
Puget Sound Energy
Location: 10608 NE 4 St, Bellevue WA
External Phone: (425) 462-3579
Internal Phone: 81-3579

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Wednesday, August 14, 2002 8:22 AM
To: Brattebo, Scott; Carr, Geoff; CARTER, LAWRENCE; Eden, Jim; Elizeh, Edison; 'Goddard, Richard'; Groce, Ed; HORVATH, JULIUS; Johnson, Don; Juj, Hardev; KEENAN, GERALD; Kinney, Scott; KOSTEREV, DMITRY; LANDAUER, MARVIN; Leland, John; Lu, Franklin; Martinsen, John; Morris, Ken; Phillips, John; QUINATA, JOHN; Reedy, Dana; Reese, Chris; Robinett, Wayman; RODRIGUES, MELVIN; Rust, Jerry; RYDELL, KENDALL; Schellberg, Ron; Seabrook, Joe; SILVERSTEIN, BRIAN; STADLER, LAWRENCE; VANZANDT, VICKIE; Waples, Scott
Cc: Mittelstadt, Bill - TOM-PPO2-2
Subject: ITRC Report and Meeting

Per comments received during our Monday conference call I am redistributing the draft report in revisions format. Changes appear in files: "Report Draft" and "Appendix C." Additional pages are provided to Appendix D as an Excel workbook (print all worksheets).

As already noted it has been scheduled to convene the ITRC at the Portland Airport PDX conference center on Tuesday August 20 from 9 am to 2 pm to conclude any revisions to this report and conclude on the group drafted cover letter. We should plan on bringing closure to this years report at that Tuesday meeting and obtain signatures for the cover letter of those present.

If you have any further comments before that time please forward them to me.

Bill Mittelstadt

<<William A Mittelstadt (E-mail).vcf>> <<Report Draft 8~13.doc>> <<Appendix A 7~31.doc>> <<Appendix B 8~1.doc>> <<Appendix C 8~13.doc>> <<Appendix D.doc>> <<Appendix D~Worksheets 8~13~02.xls>>

Wright, April E - KFF-2

From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Wednesday, August 21, 2002 10:09 AM
To: Mittelstadt, Bill - TOM-PPO2-2; 'Morris, Ken'; 'Juj, Hardev'; 'Leland, John'; 'Martinsen, John'; 'Waples, Scott'; 'Eden, Jim'; 'Robinett, Wayman'; 'Schellberg, Ron'
Cc: Silverstein, Brian L - TOP-PPO2-2
Subject: RE: ITRC Report for Signature

Hi

The attached cover letter file has page numbering per suggestion from John Martinsen. Please use this copy for signature.

John mentioned that there was a tracking "strikeout" on page 2 under the Projects G10-G14 heading. I did not see it when I opened the file. Let me know if it continues to appear.

Bill

Cover Letter.doc

Nilliam A Mittelstadt
(E-mail)...

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Tuesday, August 20, 2002 4:44 PM
To: 'Morris, Ken'; 'Juj, Hardev'; 'Leland, John'; 'Martinsen, John'; 'Waples, Scott'; 'Eden, Jim'; 'Robinett, Wayman'; 'Schellberg, Ron'
Cc: VanZandt, Vickie - TO; Silverstein, Brian L - TOP-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2
Subject: ITRC Report for Signature

Thanks for your participation in the meeting today to complete revisions to the report and draft the transmittal cover letter. Please mail and fax a signed copy of the letter to me by Friday August 24. We do not have the attachment referenced in the cover letter in electronic form and will obtain a copy to include with the report when it is distributed.

My address and phone numbers are:

William Mittelstadt PPO2-2 TOM
Bonneville Power Administration
Parkway Plaza (Mail Center)
8100 NE Parkway
Vancouver, WA 98662
(360) 419-6672 phone
(360) 619-6945 fax

Thanks

Bill Mittelstadt

<< File: Cover Letter.doc >> << File: BPA Report.doc >> << File: Appendix A.doc >> << File: Appendix B.doc >> << File: Appendix C.doc >> << File: Appendix D.doc >> << File: Appendix D Worksheets.xls >>

August 20, 2002

Addressees

Subject: Infrastructure Technical Review Committee (ITRC) Report

Background

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U.S. Department of Energy, May, 2002).

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority as well as full consideration of third-party financing options. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The ITRC was formed in 2001 at the behest of some BPA customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Each year, the ITRC evaluates and works to prioritize BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. Guidelines for the review were defined in the "Agreement for Annual Review of Major BPA Transmission Investments" dated July 18, 2001 and with a update added on January 15, 2002 (attached). The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC) and the Operating Committee (OC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting a report on proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not finance the work of the ITRC.

Borrowing Authority

The committee provided its first report on August 30, 2001 with the recommendation that BPA install necessary system facilities as soon as possible. A critical first step was BPA securing additional borrowing authority. The additional borrowing authority was not approved last year. Unless additional borrowing authority is approved this fall some needed projects will be delayed, putting reliability at risk and inhibiting construction of new generation. The resulting congestion and reduced capacity margins will lead to higher prices and increased market volatility.

Projects G10-G14

Attached is the second annual report on the transmission infrastructure proposal that contains BPA's conclusions and recommendations to the review committee. The report addresses four additional projects. The committee supports BPA's findings as summarized below:

- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G11 (South Seattle Transformer) will be submitted for future review.
- Project G12 (Olympic Peninsula Reinforcement) is also important. The need date to prevent area problems for first contingency (N-1) outages is later than initially estimated based on the most recent load forecasts. Planned and controlled loss of area load is permitted under the NERC/WECC Planning Standards for the exposure to double contingency (N-2) outages provided that system cascading does not result. Opportunities for non-transmission alternatives are being pursued in parallel with the proposed transmission fix.
- Project G13 (Paul – Troutdale 500-kV Line) will continue to go through the WECC Regional Planning Process this year in expectation that it will be ready to be considered by the ITRC in 2003.
- Project G14 (Hanford-Ostrander 500 kV loop-in) requires further analysis by BPA.

Some members of the ITRC believe that projects G12 and G13 should be accelerated.

Additional Comments

- Projects reviewed in prior years will not be extensively re-reviewed unless circumstances have changed significantly. The projects are subjected to other technical reviews (i.e., TPC, NRTA, WECC) as appropriate. BPA should provide status reports to the ITRC.
- Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure firm transmission service contracts of sufficient duration and with appropriate credit provisions before proceeding with construction.

BPA is requested to continue conducting annual reviews to evaluate and prioritize proposed major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers.

Ken Morris PacifiCorp	John Martinsen Snohomish PUD	Wayman Robinett Puget Sound Energy
Hardev Juj Seattle City Light	Scott Waples AvistaCorp	Ronald Schellberg Idaho Power Company
John Leland NorthWestern Energy	Jim Eden PGE Company	

cc
Infrastructure Technical Review Committee

Wright, April E - KFF-2

From:	Mittelstadt, Bill - TOM-PPO2-2
Sent:	Wednesday, August 28, 2002 8:42 AM
To:	Wright, Stephen J - A-7; Maher, Mark W - T-DITT2; VanZandt, Vickie - TO; Courts, Alan - TN-OPP-3; Johnson, Frederick M- TF-DOB1; Silverstein, Brian L - TOP-PPO2-2; Haner, John - TOM-PPO2-2; Kreipe, Mike - TOP-PPO2-2; Rodrigues, Melvin - TOP-PPO2-2; Horvath, Julius G - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; Carter, Lawrence D - TOP-PPO2-2; Watkins, Donald S - TOT-DITT2; Quinata, John F - TOE-PPO1-2; Mahar, Dulcy - KC-7; Bennett, Ruth - TM-DITT2; Lahmann, Bob - TM-Ditt2; Johnson, Frederick M- TF-DOB1; Whitney, Carolyn A - T-DITT2; Raschio, Mike - TM-Ditt2
Cc:	Mittelstadt, Bill - TOM-PPO2-2; Regalado, Ann-Marie - TOM-PPO2-2; Stout, Debbie - T-DITT2; Speer, Cheryl - TO-DITT2; Holcomb, Linda L - TOP-PPO2-2
Subject:	Infrastructure Technical Review Committee Report

Attached is a copy of the recently completed **Infrastructure Technical Review Committee Report** for the second year. The purpose of this report is described in the attachment to the cover letter. A hard copy of this report will be sent to you soon and it will be posted as a PDF file on the BPA external web page as before. Copies of the report will also be mailed to the principals of each of the participating utilities.

If you have any questions about the report please feel free to contact Brian Silverstein (6651) or Bill Mittelstadt (6672). Also please share this with others who may need the information.

Projects reveiwed this year are summarized as follows:

- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
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Thank you

Bill Mittelstadt
(360) 619-6672

Cover Letter .doc   Cover Letter Attachment.doc   BPA Report.doc   Appendix A.doc   Appendix B.doc   Appendix C.doc   Appendix D .doc

Appendix D Worksheets.xls

August 20, 2002

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Ken Morris
PacifiCorp

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Snohomish PUD

Wayman Robinett
Puget Sound Energy

Hardev Juj
Seattle City Light

Scott Waples
AvistaCorp

Ronald Schellberg
Idaho Power Company

John Leland
NorthWestern Energy

Jim Eden
PGE Company

cc
Infrastructure Technical Review Committee

Annual BPA Transmission Infrastructure Review
January 15, 2002

Purpose

This paper clarifies the procedures to be used by a review committee established by the July 18, 2001 *Agreement for Annual Review of Major BPA Transmission Investments* (attached). This paper must be read in conjunction with this underlying agreement between the Northwest investor-owned utilities and BPA. This paper is not intended to change the underlying agreement.

The basic purpose of the annual BPA Transmission Infrastructure Review is to evaluate the business and technical justifications for proposed investments by BPA in transmission for the succeeding 5 year period. To this end, an infrastructure review committee has been established. The committee is composed of representatives of BPA transmission customers and BPA. Committee members have business and technical expertise in transmission planning and operational issues.

The committee will conduct an annual review of all proposed BPA transmission investments exceeding $10 million over the upcoming five-year budget cycle. Each subsequent year, the annual review will focus on the succeeding five-year period (see Finality, below).

The committee will evaluate proposed transmission projects based on whether they would provide appropriate business, technical and cost-effective solutions to identified problems, based on a "single utility" planning concept. The scope of this review includes load center reliability, congestion relief, transmission customer service requests, generation integration, meeting contract commitments, efficient use of capital and schedules for project completion.

BPA will investigate all the alternatives (transmission, non-transmission and do-nothing) and present the rationale for its recommended alternative. This rationale will include BPA's risk and uncertainty analysis and other decision-making criteria. Parties offering further alternatives for consideration must provide a well-developed proposal. It will then be BPA's responsibility to include and evaluate any alternatives in its analysis.

Other Transmission Review Processes

This annual BPA Transmission Infrastructure Review is in no way intended to replace or diminish any other established review processes, including the NWPP TPC Joint Planning Process and the NRTA and WSCC Regional Planning Processes. (Moreover, this paper is not intended to describe how these other important technical reviews are structured or will proceed.)

In general, the annual BPA Transmission Infrastructure Review should occur, to the extent possible, simultaneously or in tandem with other reviews of BPA project proposals. To some degree, the infrastructure review will rely on these other processes to identify technical problems and alternative solutions to be considered. At the same time, the business rationale for any BPA project must be considered in tandem with technical considerations. Therefore, the expectation is that the business review will be performed in parallel with other reviews and be complementary to them.

Product

The committee will produce an annual report describing the committee's work and whether it finds that BPA is prioritizing its transmission improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers.

Timing

The first annual review occurred in August 2001. All parties who participated in this first annual review agree that more time is needed to perform the committee's work and produce a quality product. There is also agreement that going forward, the annual review should be performed and the final report produced in a timeframe where it will have maximum usefulness relative to the annual budget appropriations and Congressional cycle. To accomplish the maximum usefulness for the annual (next year) budget, the review will also focus on projects in the 2-5 year timeframe. This longer-term review will allow input to project planning before decisions are made in the annual budget process. Thus, going forward, the annual review should abide by a work plan that allows meaningful, substantive review to occur and a final report produced no later than May 30 each year.

To this end, the following general schedule will be followed:

February 1 -- BPA submits and presents its draft plan including all initial economic analysis and other relevant support materials to the committee. (The initial meeting will be timed to dove-tail with a TPC meeting already scheduled.)

February 15 -- The committee submits all data and clarification requests to BPA.

February 28 -- The committee reconvenes, BPA answers all data requests.

March/April --Subsequent meetings and analysis as required by the committee.

April 30 -- The committee completes a draft report.

May 30 -- Final report is completed.

Finality

There needs to be some finality to the annual review. Members of the committee recognize the need to move to resolve pressing transmission constraints and not endlessly debate alternative solutions. At the same time, circumstances are always changing and at times a re-review of pending project proposals may be appropriate as discussed below.

Major projects that have been reviewed and approved by the annual BPA Infrastructure Review Committee will not be subject to extensive review in subsequent annual reviews, with the following two important exceptions:

1) Many previously recommended projects will be multi-year investments and will continue to be included in the BPA budget. In subsequent annual reviews, BPA will provide status reports on these ongoing or pending projects, upon the request of the committee. (These status reports will include all relevant factors, including changes in load and generation forecasts, cost estimates, and construction schedule.)

2) Not withstanding recommendation in prior infrastructure reviews, if there is a significant change in circumstances that may implicate the business case for a specific project, the committee will undertake a full review of the project. (Examples of changes in circumstances may include significant change in project costs, changes in load or generation, alternative solutions that have surfaced and may be more cost-effective, or other changes in expectations relative to when the project was previously reviewed and recommended.)

Finally, a recommendation or endorsement of a project by the annual BPA transmission infrastructure review committee does not in any way prejudge, supplant, diminish or eliminate the importance of subjecting the project to other existing technical reviews, including the NWPP TPC Joint Planning Process and the WSCC and NRTA Regional Planning Processes. The general expectation is that projects reviewed by the infrastructure review committee will also be subject to these other review processes.

Openness

The committee will be composed of representatives of BPA transmission customers and BPA, as described above. The meetings of the committee will be open to anyone and everyone who has an interest in the proceedings.

Attachment

Agreement for
Annual Review of Major BPA Transmission Investments
July 18, 2001

How the review committee will work:

- An independent technical review committee ("committee") will be formed, consisting of representatives of BPA's transmission customers and BPA. Committee members shall have business and technical expertise in transmission planning and operational issues. BPA and its transmission customers agree to work together in good faith to determine a mutually agreed upon committee roster in a timely fashion.
- The initial annual review will occur during August, 2001, for the purpose of reviewing proposed BPA transmission investments over $10 M for the next five years (2002 - 2006). Each year, the committee will review proposed transmission investment decisions for the succeeding five-year period.
- The committee will evaluate proposed transmission projects based on whether they would provide appropriate business, technical, and cost-effective solutions to identified problems, based on a "single utility" planning concept. The scope of review will include load center reliability, congestion relief, generation integration, meeting contract commitments, and schedules for project completion. The committee's scope of work is limited to transmission issues, and does not include transmission facility siting.
- The committee will work to assure that the proposed transmission investment program prioritizes BPA's transmission improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. The committee will produce an annual report describing the committee's work and whether it finds that BPA is prioritizing its transmission improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers.
- The goal will be a report that enjoys the unanimous support of the committee. Failing agreement, a majority vote will determine the content. Each BPA transmission customer committee member shall have one vote. BPA will be an ex-officio member of the committee.
- BPA is not legally obligated to abide by any recommendations made by the committee.

How we will ask for the support of Congress:

- We will ask the Senate Appropriations Committee to include the following language in its report, at the point where it is discussing an increase in BPA's borrowing authority:
  "The Committee is aware that BPA and many of its transmission customers have agreed to form a technical review committee to assure that BPA's transmission investments are prioritized to ensure cost-effective and reliable service for the consumers of the Northwest. The Committee fully supports the formation of this committee."

Upgrading the Capacity and Reliability of the BPA Transmission System

Report to the Infrastructure Technical Review Committee

August 20, 2002

Table of Contents

Appendices

Please refer to the August 30, 2001 Infrastructure Review Committee report for information on the purpose of this Committee, terms of engagement and general system need. Also please refer to this report for system maps.

1.1 Background

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002). Problems with transmission in the region are manifested in several ways:

- Chronic congestion existing on a number of transmission paths requires curtailment of both firm power deliveries and economy energy.
- Continued resolution of the Western energy crisis requires development of new generating resources. The vast majority of proposed Northwest resources cannot obtain firm transmission service, or be integrated, without additional Bulk Transmission.
- It is extremely difficult to meet obligations when facilities are removed from service to conduct normal maintenance or to construct new facilities.
- While power loads have been growing steadily at 1.8% annually and the use of the transmission system is up by over 2% annually, few Bulk Transmission lines were added in the past 15 years.
- It will take much longer to site and build transmission to deliver needed new generation than it will take to build and site the generation. New transmission is needed to meet statutory, treaty and contractual obligations and comply with national and regional standards that ensure a reliable power system[1].

As the operator of three-quarters of the Bulk Transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The Infrastructure Technical Review Committee (ITRC) was formed in 2001 at the behest of some of BPA's customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Once a year, the ITRC evaluates and prioritizes BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC), Operating Committee (OC) and the Northwest Regional Transmission Association (NRTA) Planning Committee (PC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not fund the work of the ITRC.

The committee was asked to report its initial recommendations by August 30, 2001 to enable BPA to install necessary system facilities as soon as possible.

This review is the second in an annual process to coincide with BPA's annual budget cycle. It covers four projects of BPA's infrastructure proposal. Review of additional projects will be conducted in subsequent years. There are several additional parallel efforts that provide for review of proposed transmission additions. This committee's analysis and recommendations will be shared and further analyzed in the following forums.

- Northwest Power Pool (NWPP) Transmission Planning Committee
- Western Electricity Coordinating Council (WECC) Regional Planning Group
- National Environmental Policy Act (NEPA) review for individual projects

During the first part of 2002 the committee met twice to review additional infrastructure proposal developed by BPA. While some of the proposals have been under development in previous forums with outside participation, other proposals were presented for the first time. BPA conclusions and recommendations given on the following pages.

1.2 Projects Reviewed in 2002

There continues to be a compelling and immediate need to complete the projects reviewed in 2001 and to further upgrade portions of the Northwest Bulk Transmission grid. Solutions proposed by BPA in coordination with others address the identified problems. Detailed descriptions are given in Appendix C together with the economic analyses in Appendix D.

- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G11 (South Seattle Transformer) is not addressed at this time and will be submitted for future ITRC review.
- Project G12 (Olympic Peninsula Reinforcement) is also important. The need date to prevent area problems for first contingency (N-1) outages is later than initially estimated based on the most recent load forecasts. Planned curtailment of area load is permitted under the NERC/WECC Planning Standards for the exposure to double contingency (N-2) and bus outages provided that system cascading does not result. Opportunities for non-transmission alternatives are being pursued in parallel with the continued review of the proposed transmission fix.
- Projects G13 (Paul – Troutdale 500-kV Line) and G14 (Hanford-Ostrander 500 kV loop-in) were examined on a preliminary basis. Project G13 is critical to integration of new generation in the I-5 corridor. BPA will complete details of the plan of service over the next 60 days and bring this through the WECC Regional Planning Process. In addition, coordination with PGE and PacifiCorp is required in relation to their respective transmission and generation expansion plans.
- The benefits of project G14 are not clear given proposed I5 generation development and potential higher costs to route around the Columbia Gorge Scenic Area. BPA will bring these projects forward to the committee for consideration in 2003 after further examination of alternatives and need.

Table 1. 2002 Recommended Projects

Project		Capital Cost (loaded) ($M)	Energization Date	Capacity Added MW
Portland Area Additions	G10	9	2003	300
Olympic Peninsula Reinforcement	G12	26	2005	430
Total		35		

Table 2. Drivers for 2002 Recommended Projects

	Load Service	Entitlement Return	Generation Integration	Transfers	Reliability	O&M Savings	BiOp
G10	x				x		
G12	x				x		

1.3 Projects Reviewed in 2001

- Projects evaluated in previous years should continue on the revised timetable proposed by BPA. BPA will continue to reevaluate project need and timelines, particularly for projects driven by generation integration.
- In accordance with provisions in the January 15, 2002 guidelines[2] BPA provided a status report on projects that were reviewed last year. There were no significant changes in circumstances that necessitated any of these projects be returned to the committee for a full review.
- Section 1.5 provides a status report on these projects G1-G9.

1.4 Rate and Budgetary Impacts

As started earlier, there continues to be a compelling and immediate need to continue to upgrade portions of the Northwest Bulk Transmission grid and capital to meet that need.

- Figure 1 illustrates the historical and projected transmission capital requirements forecasted by BPA over a ten-year planning horizon. The capital outlay from 2001 and beyond, including the infrastructure proposals, is well above BPA's remaining borrowing authority. Accordingly, the need still remains to increase BPA's borrowing authority for *transmission* by at least $1 billion in order to ensure that sufficient financial resources are available.
- BPA will continue to pursue and evaluate third-party financing opportunities for major new transmission projects.
- Preliminary analysis for the individual projects show that in some cases the cost will be fully recovered by increased usage and may put downward pressure on rates. Other projects that are driven by reliability needs may put upward pressure on rates. Details on the economic analysis are given in Appendix D. This report is not intended to be a rate projection.
- Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure firm transmission service contracts of sufficient duration and with appropriate credit provisions before proceeding with construction.
- Additional reinforcements by BPA and others are needed to maximize reliability and transfer capability from the proposals. Other Northwest utilities have planned and in some cases committed to transmission additions, and maximum benefits will be achieved through coordinated development.

Future reviews will be conducted annually to evaluate and prioritize BPA proposed major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers.

1.5 Status of Projects Reviewed in 2001

Projects G1-G9 reviewed in 2001 remain in the construction program but in some cases with revised energization dates, or subject to commitments from proposed generation plants. A brief status statement follows on each of these projects:

G1 Puget Sound Area Additions (Kangley – Echo Lake 500 kV Line)
The energization date for this project has set back one year to Fall 2003 to allow a full analysis of alternatives through the environmental process. Based on approval by WECC the outage of the Raver – Echo Lake and Schultz – Echo Lake lines on common rights of way has been granted an exception from two-line outage requirements and reclassified as NERC/WECC Category D (exploratory). The Snoking 500/230 kV transformer energization has also been delayed by one year to Fall 2003.

G2 North of Hanford (Schultz – Wautoma 500 kV Line and Wautoma Substation)
This project is proceeding forward on the Fall 2004 schedule with no change in status.

G3 McNary – John Day 500 kV Line
This project is proceeding forward on the Fall 2004 schedule with financial commitments having been received from generation projects for preliminary design and environmental work.

G4 Lower Monumental – Starbuck 500 kV Line
Need for this project is presently uncertain due to delay of the Starbuck generation project. Continuation of this project will depend on resumed development of this site and agreements for financing of the transmission project.

G5 Smiths Harbor – McNary 500 kV Line
Work is proceeding on plans for construction of the substation at Smiths Harbor based on commitments from the Smiths Harbor generation project. Need for the transmission project depends on plans to move forward with the Starbuck generation project or other generation in the area.

G6 Schultz Series Capacitors
This project is proceeding ahead for completion in Fall 2003 per the original schedule.

G7 Celilo Modernization
Work is proceeding on this project with the expected energization revised from Fall 2003 to Summer 2004.

G8 Monroe – Echo Lake 500 kV Line
Non-transmission solutions are being reviewed by BPA as possible alternatives for this project scheduled for Fall 2005.

G9 Bell – Coulee 500 kV Line
This project, which is intended to increase capacity across the West of Hatwai bottleneck, is on schedule for Fall 2004 energization as reported in last year's report. Since that time,

agreement has been reached on additional Phase 1 facilities (many of which were included on the list of potential Phase 2 projects in the 2001 Infrastructure Technical Review Committee Report), which are presently planned for energization between 2003 and 2007. These facilities and modifications, which will be constructed/implemented by the Avista Corporation, include the following:

- Benewah-Shawnee 230 kV Line.
- Dry Creek 230 kV Switching Station.
- Beacon-Rathdrum Double Circuit 230 kV Line.
- Increase operating limits on Hatwai-Lolo 230 kV Line.
- Increase operating limits on Hatwai-North Lewiston 230 kV Line.
- Increase operating limits on Dry Creek-North Lewiston 230 kV Line.
- Install 230 kV shunt capacitors at Benewah (200 MVAR).
- Install 230 kV shunt capacitors at Dry Creek (200 MVAR).

All of the facilities listed above will be taken through the WECC Regional Planning Process. Since the Bell-Coulee 500 kV line has already been through the process, it is expected that this will be an abbreviated process with comments only for the additional facilities. Any additions or changes to the above list of projects will be identified through the Regional Planning Process. The complete slate of Phase I facilities reinforcing the West of Hatwai Path including the Coulee – Bell 500 kV line will then be taken through the WECC Path Rating Process. Additional (West of Hatwai Phase II) facilities, which may be necessary in the Northern Idaho / Western Montana area will be identified in a follow up effort.

1.6 Glossary of Acronyms and Terms

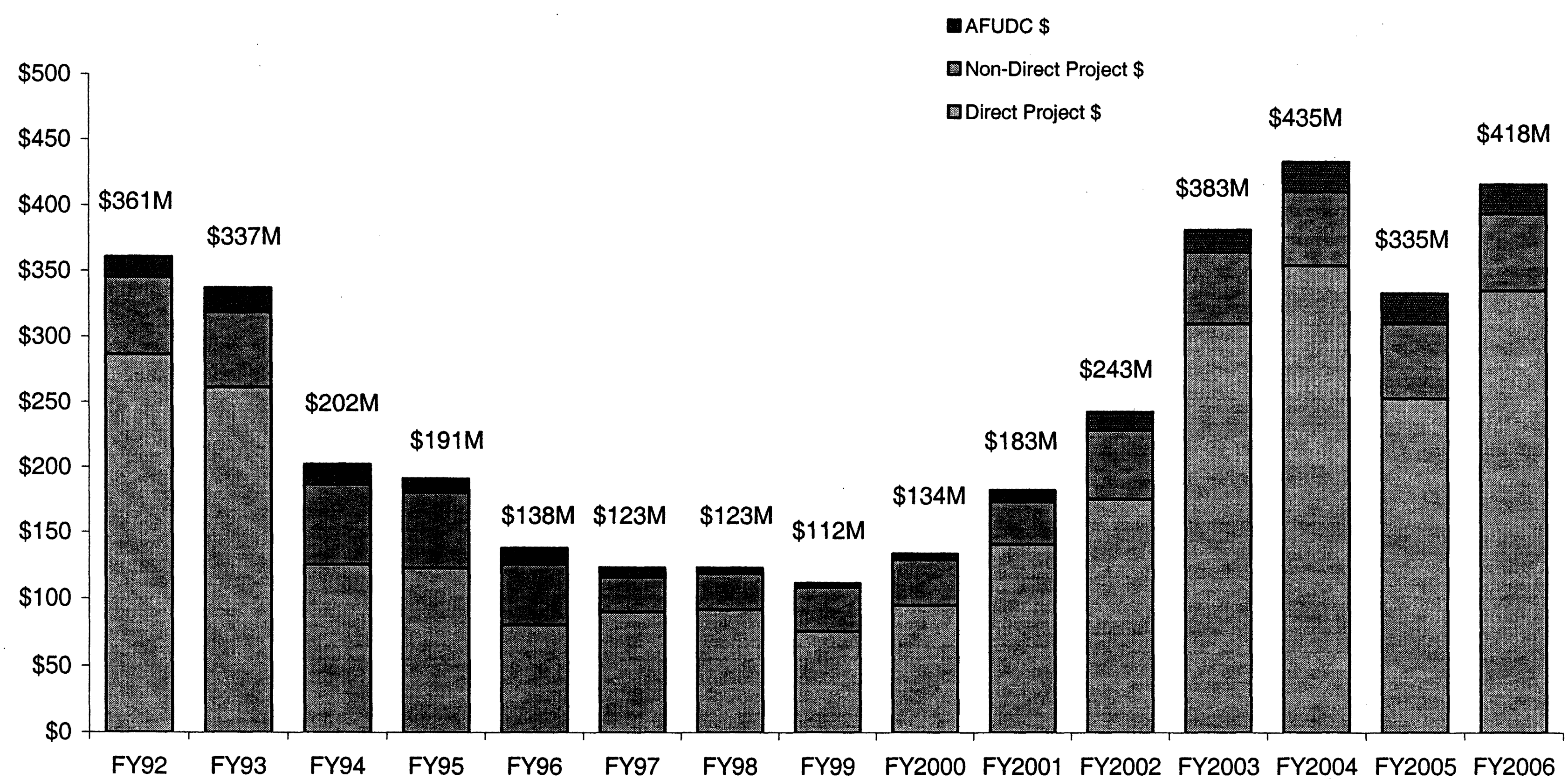
BiOp	Biological Opinion
MW	A unit of power. One MW would serve approximately 700 homes.
NRTA	Northwest Regional Transmission Association
NWPP	Northwest Power Pool
RTO	Regional Transmission Organization
WECC	Western Electricity Coordinating Council

Bulk Transmission – Transmission lines that serve as the backbone of the grid, typically operated at voltages of 230-kV and above.

1.7 References

[1] "NERC/WECC Planning Standards, Board of Trustees approved April 18, 2002.
[2] "Annual BPA Transmission Infrastructure Review," January 15, 2002.

Figure 1. TBL Capital Projects Historical & Future Trend



Appendix A – Participants

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Appendix B –Project Schedules

Project		Energization
Kangley - Echo Lake 500 kV line	G1	Fall 2003[1]
Schultz - Wautoma 500 kV line	G2	Fall 2004
McNary - John Day 500 kV line	G3	Fall 2004
Lo Monumental - Starbuck 500 kV line	G4	Fall 2004[2]
Smiths Harbor - McNary 500 kV line	G5	Fall 2004[2]
Schultz series capacitors	G6	Fall 2003
Celilo Modernization	G7	Summer 2004[1]
Monroe - Echo Lake 500 kV line	G8	Fall 2005
Bell - Coulee 500 kV line	G9	Fall 2004
Pearl Transformer	G10	Fall 2003
South Seattle Transformer	G11	Fall 2004[2,3]
Olympic Pennsula Reinforcement	G12	Fall 2006[1,2]
Paul - Troutdale 500 kV line	G13	Fall 2005[3]
Hanford - Ostrander loop-in	G14	Spring 2005[2,3]

Notes:
1 Denotes change from September, 2001 report
2 Energization may change depending on need.
3 To be submitted for future ITRC review.

Appendix C – Project Summaries

G10. Portland Area Additions (Pearl 500/230 kV Transformer)

Background

The Portland area is currently served by four 500/230 kV transformers: Troutdale on the east side, McLoughlin in SE Portland, Pearl in SW Portland and Keeler on the west side. This project is another phase of reinforcing the load serving capability from the bulk transmission system into the greater Portland area. Earlier reinforcements included adding a new 230 kV double-circuit line between Pearl and PGE's Sherwood substation.

Addition of the 2nd transformer at Pearl will require extension of both the 500 kV and the 230 kV buses. These extensions are within the existing Pearl substation.

Limiting Outages Addressed

Existing Pearl 500/230 kV Transformer

Benefit – Load Area Service

This project will increase the load carrying capability into the greater Portland area. Without this project it would be necessary to trip off load in the Portland area to relieve overloads during abnormal cold winter peaks for an outage of the existing Pearl transformer.

Business Case

This project provides the capacity to carry additional Portland area load increasing at the rate of 75 MW per year from 2004 though 2007. Beyond that date it will provide load serving benefit to the capacity of the bank following a suitable plan to address the Big Eddy – Ostrander 500 kV line outage. For the purpose of this analysis the benefit stream is limited to 300 MW for the period beyond 2007. In the Table below, Alternative 1 is the preferred plan. Alternatives 2-5 are described on the next page and on the following table is the financial analysis for alternatives 1-3.

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV	Rev/C	Repayment Years	In Service	Life
1	30.8	11.2	19.6	2.75	6	2003	2037
2	30.8	32.6	(1.8)	0.95	14	2003	2037
3	30.8	54.4	(23.7)	0.57	25	2003	2037
1a (0.9%)	26.9	11.9	15.0	2.26	8	2003	2037

Risk Factors

The following table qualitatively addresses various risk factors:

Factor	Risk	Factor	Risk
Cost	Invoiced	Delivery on time	In inventory
Siting/ROW	Existing site	Funding	Available
Load Growth	See sensitivity 1a	Discount Rate	Not considered

The proposed site has space reserved for the transformer addition. Since this does not involve work outside the substation there are no environmental risks. The Revenue/Cost ratio remains favorable with half the of the projected load growth (1a). Accordingly, this is considered to be a very low risk project.

Project Description (Alternative 1)
This project adds a 2^{nd} 500/230 kV transformer at the existing Pearl Substation. The new transformer will be 3 single-phase units (433 MVA each). The new bank will be equipped with a 9 step LTC and a tertiary for station service. One 500 kV breaker and one 230 kV breaker will be added. The 500 kV and 230 kV buses will be extended.

Alternatives Considered

2. Install a 500/230 kV transformer at PGE's Sherwood Substation. This location would be higher cost, require additional property and would be difficult to site. It was considered in the past, but the decision was made to increase the 230 kV capacity between Pearl and Sherwood.
3. Install a 500/230 kV transformer at McLoughlin Substation.
4. Curtail load in the event of a transformer outage (Do Nothing).
5. Non-transmission alternatives.

Alternatives #2 and #3
Alternatives 2 and 3 listed above have capital costs of $24.5 M and $36 M, respectively as compared to $9 M for alternative 1.

Do-Nothing Alternative (#4)
The "no build" alternative represents the risk of load interruption for a first contingency 500/230 transformer outage at any of the four following locations: Keeler; Pearl; McLoughlin; Troutdale. Load interrupted ranges from 75 MW in 2004 to 900 MW in 2015. Based on a single phase transformer outage failure rate of once per 100 years the outage mean time between failure (MTBF) is estimated as follows:

P(no outage) = (1-1/100)^(4 banks*3 transformers/bank)
P(no outage) = 0.886
P(outage) = 1-0.886 = 0.114
MTBF = 1/0.114 = 8.8 years

While the revenues for the do-nothing alternative can be assumed to be the same assuming load can be carried under the no-outage condition, the societal cost of a bank outage would be significant. Assuming that load is curtailed to the outage limit for a period of one week until a new transformer unit is installed the present worth societal cost over ten years of service is estimated to be about $4.9 M. This is calculated using the above MTBF estimate, the following load interruption cost figures inflated yearly by 2.64% and assuming the system exposure is 8 hours/day for two months/year.

Load Type	Composition	$/kWHr (2002)
Residential	50%	$1.66
Commercial	30%	$18.50
Industrial	20%	$27.56

Non-Transmission Alternatives (#5)
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and Environmental Economics, Nov. 2001 available at:

http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm.

Non-transmission alternatives can not be implemented in time to be considered a viable alternative to this project.

Analysis
BPA chose the preferred plan for the following reasons:
- Lowest cost
- Essentially no environmental impact (existing site)
- Favorable Revenue/Cost ratio (2.75)
- Favorable economics under reduced load growth rate
- Short repayment period (6 years)

Energization Date: **Fall 2003 (Preferred Alternative)**
Estimated Cost: **$9M**

G12. Olympic Peninsula Reinforcement (Paul-Shelton 500-kV line)

Background
The Olympic Peninsula area load is served from Olympia substation via 230-kV and 115-kV transmission. The major source to Olympia to serve these loads is the 500-kV transmission line from Paul substation. An outage of this 500-kV source to Olympia would result in a voltage collapse during extra heavy winter load conditions. A second 500-kV source is needed to solve the voltage collapse problem as early as 2003. A shunt capacitor group to be installed in 2003 will delay the need for this project until 2005. With this addition the Olympic Peninsula transmission system has reached the limit that can be supported by shunt capacitors. A total of 20 capacitor groups amounting to approximately 900 MVAR will have been installed.

In addition, a double-line outage of the 230-kV double-circuit line from Olympia to Shelton or a breaker failure at Olympia will result in a total loss of the Olympic Peninsula during normal winter load. The proposed reinforcement will solve both the N-1 and N-2 problems and reinforce the Olympic Peninsula region.

Limiting Outages Addressed
- Olympia 500/230-kV transformer
- Paul-Olympia 500-kV line
- Olympia-Shelton 230-kV double line
- Olympia 230 kV West or East bus outage
- Olympia 230-kV breaker failure

Benefit - Load Area Service
This project will prevent these outages from impacting service to the Olympic Peninsula by providing a second source of power to the Peninsula from Paul Substation. This project will also increase the load service capability to the Olympic Peninsula under non-outage conditions as well as mitigate or delay other system upgrades that would be needed in the future if this project were not built.

Business Case
This project provides the capacity to carry additional projected normal winter load in the Olympic Peninsula area in compliance with NERC/WECC Planning Standards for Category A-C outages. For the purpose of this analysis revenues are based on 1.8% load growth corresponding to 26 MW/year reaching a project limit of 338 MW in 2019. In the Table below, Alternative 1 is the proposed plan and Alternative 2 would involve moving the 500/230-kV transformer to Olympia (see below). Alternatives 1a-1c are sensitivity studies discussed under "Risk."

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV	Rev/C	Repayment Years	In Service	Life
1	21.6	29.3	(7.8)	0.74	20	2006	2040
1a	35.7	35.5	0.2	1.00	20	2006	2040
1b	14.4	34.1	(19.7)	0.42	31	2006	2040
1c	21.6	32.7	(11.1)	0.66	22	2006	2040
2	21.6	27.2	(5.7)	0.79	19	2006	2040

Risk
The following table qualitatively addresses various risk factors. Three are identified for evaluation.

Factor	Risk	Factor	Risk
Cost	**See sensitivity 1c**	Delivery on time	Routine purchases
Siting/ROW	Existing site/ROW	Funding	Available
Load Growth	**See sensitivity 1b**	Discount Rate	**See sensitivity 1a**

Sensitivity 1a – This case determines what discount rate is needed to achieve a Revenue/Cost ratio of 1.0. This is achieved by a discount rate of 6.5%, giving an equivalent rate of return on investment of 6.5% over the 34 year life of the project.
Sensitivity 1b – In this case the load growth rate of 1.8% is cut in half to 0.9%. This reduces the Revenue/Cost ratio from 0.74 to 0.42 and extends the repayment period from 20 years to 31 years.
Sensitivity 1c – This case represents an increase in project cost of 10%. The Revenue/Cost ratio for this case dropped from 0.74 to 0.66 and the repayment period increased from 20 years to 22 years.

Project Description

- Build approximately 13.8 miles of 500-kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to the Shelton 500 kV yard. The line will be routed on the existing Olympia-Shelton right of way. Cut the Paul-Satsop 500 kV line at corridor intersection and connect the Paul end to new 500 kV line to Shelton.
- Remove Olympia-Shelton 115 kV line #1 from Olympia to Dayton Tap.
- Construct a 500 kV yard approximately 1 mile south of the existing Shelton substation, move Satsop 500/230 kV transformer to this location and tie it to Shelton 230 kV bus via 1 mile long 230 kV line.
- Build approximately 6 miles of new 230 kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to Olympia substation. Connect this new line to Satsop end of cut Paul-Satsop 500 kV line.

Alternatives Considered

2. Move Satsop 500/230 kV transformer to Olympia substation and terminate the Paul-Satsop 500 kV line at Olympia.
3. No build alternative
4. Non-transmission alternatives

Alternative #2
Alternative #2 listed above has approximately the same capital cost as alternative #1.

Do-Nothing Alternative (#3)
(a) The following information applies to voltage collapse for N-1 contingencies for extra heavy winter if the transmission system is not reinforced:

- A 2 year MTBF for N-1 Paul-Olympia 500 kV line with average outage duration of 2.5 hours.
- A 100 year MTBF each phase of the Olympia 500/230 transformer and a 4 week replacement time. This corresponds to a bank outage probability of:

  P(outage) = 1-(1-1/100)^3 = 0.030, and a
  MTBF = 1/0.030 = 34 years.

- The required load curtailment for either outage increases by 26 MW yearly starting in 2006.

Since the outage time is quite different for the two events the societal costs are estimated separately. Voltage collapse is assumed to occur when the demand exceeds capacity following the outage by more than 100 MW. Area load is restored to the capability of the remaining system within one hour. Using the same customer outage costs as with G10 the present worth societal costs of the N-1 line outage is $1 M and the N-1 bank outage is $5.65 M for a ten year period.

(b) The following information was used to estimate the probability of loss of load for N-2 contingencies if the transmission system is not reinforced:

- 9.3 year MTBF for N-2 outage of Olympia – Shelton 230 kV lines 3 and 4. It is further assumed that one line can be restored within one hour and the second line within 24 hours.
- 0.018 breaker failures/year for each of eight breakers at Olympia. It is assumed that full service is restored within one hour by moving the affected line over to the bus tie breaker. This corresponds to a bus outage probability of

  P(outage) = 1-(1-0.018)^8 = 0.14, and a
  MTBF = 1/0.14 = 7.4 years.

Again, the societal costs of the two events are treated separately. In each case it is assumed that the entire area load will be lost due to voltage collapse for the initial period of one hour. The estimated present worth societal costs are: $5.06 M for the two-line outage and $500 K for the breaker failure outages.

Overall then the estimated present worth societal cost for a ten year period of the do-nothing alternative is approximately $15.7 M. The present value savings of a ten-year delay in the project is expected to be greater considering deferred capital, financing and O&M costs.

Non-Transmission Alternatives (#4)
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and

Environmental Economics, Nov. 2001 available at
http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm.

These measures could cost-effectively defer the need under N-1 contingencies, although they can not address the N-2 problems. BPA will further consider non-transmission alternatives before proceeding with this project. Cost information is not available at this time to allow presentation of an economic analysis.

Reliability Considerations
The NERC/WECC Planning Standards address planning requirements for the various contingencies applicable to this project. Planned loss of demand or curtailment of firm transfers is permitted for the case of the double line outage (N-2) and the stuck breaker but not for the single contingency outage (N-1). Cascading outages are not permitted. Cascading is "...the uncontrolled successive loss of system elements triggered by an incident at any location...and results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies."[1] To meet these requirements a solution must be in place not later than the time (1) the system is adversely impacted for single contingency outages or (2) cascading outages occur for the less probable breaker failure and double contingency outages. In the event that loss of demand or firm transfers are indicated than it is on a planned basis " to maintain the overall security of the interconnected transmission system." In the case of this project these contingencies will not result in cascading or impact the security of the overall system. However, the societal impact of these low likelihood events will continue to be examined as another indicator affecting project need date.

Analysis
BPA has selected a preferred transmission plan from the alternatives considered, but has elected to defer a decision on the project to allow time for further development of the non-transmission alternative (#4) and to consider public input before proceeding.

Of the transmission alternatives considered, the preferred plan is Alternative 1 because it outperforms the Olympia option for both N-2 critical outages for essentially the same present worth cost without O&M expenses included. O&M costs would be higher for the Olympia option based on the amount of extra equipment that would be needed at the Olympia substation. The Olympia option would require major 230 kV work at the Olympia substation, including expansion of the 230 kV yard. Land would also have to be purchased around the 500 kV yard for 230 kV line routing into the 230 kV bus. Some of the line routing into the 230 kV bus may not even be physically possible based on current line routing, tower and road locations, land needs and right-of-way widths. The Shelton option has 8 MW less losses than the Olympia option based on 1170 MW of load, which is equivalent to normal winter load in 2002-03. These losses will increase with increases in load. The Shelton option would leave the system better prepared for the future.

BPA will further consider non-transmission alternatives before proceeding with this project.

Energization Date: Fall 2006
Estimated Cost: $23-26 M

G13. Paul – Troutdale 500-kV Line

Background
The existing I-5 corridor transmission system is limited to:
- 2400 MW North of Allston by a double Paul – Allston 500-kV line outage
- 1650 MW South of Allston by the Allston – Keeler 500-kV line outage

With new generation projects proposed in the area, the existing system is not adequate to provide transmission service to most new generating projects on a firm basis, likely resulting in generation curtailments.

At present, the double Paul – Allston 500-kV line outage requires 2850 MW generation dropping and opening of both Chehalis – Longview 230-kV line that run in parallel to the Paul – Allston line. This sectionalizing removes the northern feed into Portland metro area, resulting in load service only from the east side through Ostrander. Sectionalizing greatly reduces reactive margins in the system, which will become a limiting factor as load grows in Portland area. Sectionalizing was also shown to degrade transient stability performance.

Currently, the Allston – Keeler 500-kV line outage requires generation dropping up to 2850 MW to prevent thermal overloads. Historic data indicates that there were 19 line outages in the past 16 years, mostly cased either by lightning hits or trees. It is very desirable to reduce generation dropping amount for a single contingency since these are more frequent than multi-contingency outages.

This project is being taken through the WECC Regional Planning process.

Limiting Outages Addressed
Paul – Allston 500-kV double line
Allston – Keeler 500-kV line
Keeler – Pearl 500-kV line
Keeler breaker failure

Benefits

Table 1. Generation projects proposed in the area affecting transmission needs:

Project	Capacity	Energization	North of Allston	South of Allston
Napavine[1]	600	11/1/03	More stress	More stress
Grays Harbor I[1]	630	6/1/03	More stress	More stress
Longview – Enron	300	7/1/03	Less stress	More stress
Mint Farm[1]	280	5/1/03	Less stress	More stress
Summit	530	11/1/03	Less stress	More stress
Big Hanaford	250	In Service	More stress	More stress
Port Westward	650	12/31/03	Less stress	More stress
Centralia efficiency	70	In Service	More stress	More stress
Grays Harbor II	630	11/1/04	More stress	More stress

[1] Under construction

It is evident that new generation will greatly increase stress on the constrained I-5 paths. The existing system is not adequate to provide transmission service to most generating projects on a firm basis, and with several projects already in construction generation curtailments can be expected without this project. The new 500-kV line is expected to provide firm transmission rights for the proposed projects in the area.

A. Transfer Increase

It is expected that South of Allston limit will increase from 1650 MW to 2,700 – 2,900 MW. The new line will eliminate or greatly reduce the need for generation dropping for N-1 outages and allow time to ramp down generation. Upgrades of parallel 115-kV and 230-kV lines may be required to get the full capacity.

B. Load Service in Winter Conditions

Studies are under way.

Business Case
This project is driven by requests for long-term firm transmission by new generation and imports. Parties requesting transmission would be expected to fund the upgrade consistent with FERC policy.

Risk
The risk associated with this project is small because the generators will be expected to finance the transmission investment and/or commit to long-term transmission service.

Project Description
At present time, the plan of service is not fully defined. Two conceptual options have been considered and studied for electrical performance. Alternative #1 includes a 500-kV line from near Longview to Troutdale, and alternative #2 is a 500-kV line from near Longview to Pearl.

Analysis
No preferred alternative is proposed at this time. The project will be returned to the Technical Review Committee for consideration in 2003 following the WECC Regional Planning Process.

Energization Date: **Fall 2005**
Estimated Cost: **$117-155 M**

G14. North of John Day/Portland Area Reinforcement – (Loop the Hanford-Ostrander 500-kV line into Big Eddy)

Background

The proposed new generation additions around the McNary area along with the new McNary-John Day 500-kV line will increase the stress across the North of John Day and the flow between John Day and Big Eddy. This project will relieve some of the North of John Day constraint and reinforce the transmission between John Day and Big Eddy. In addition, this project will also reinforce the bulk load serving capability into the greater Portland area. During abnormal cold weather, an outage of the Bid Eddy-Ostrander 500-kV line results in voltage collapse in the Portland area. This Project will in effect create a second Big Eddy – Ostrander 500-kV line and increase the load serving capability to the Portland area.

Limiting Outages Addressed

Ashe-Marion/Slatt-Buckley 500-kV double line loss (summer)
John Day-Big Eddy 500-kV double line loss (summer)
Slatt 500-kV breaker failures (summer)
Big Eddy-Ostrander 500-kV line (winter)
Pearl 500-kV breaker failures (winter)

Benefit – Congestion Relief and Load Area Support

This project will increase the North of John Day capability by approximately 250-300 MW and increase the capability between John Day and Big Eddy by approximately 600-700 MW. This project also reinforces the bulk grid to serve greater Portland area load and eliminate the need for building second Big Eddy-Ostrander 500-kV line.

Business Case

The primary drivers of this project is North to South network transfers and provide additional network capacity for service to the Portland area load. The estimated cost recovery of this project at current rates and for the alternatives considered is over 35 years. In view of the long payback period lower cost alternatives or deferral will be considered.

Risk

The benefit ascribed to this project for the Portland area load is related to the timing of the Paul – Troutdale project which in part serves this need. The portion of benefits ascribed to intertie support will be beneficial at the time the project goes into service but is not sufficient alone to ensure full cost recovery. Risk that costs will not be recovered for this project as proposed at this point is high.

Project Description

- This project consists of constructing approximately 16.5 miles of 500-kV double circuit line to the Columbia River crossing and approximately 18 miles of single circuit 500-kV line to Big Eddy and 2 miles of line to John Day.

- Develop a new 500-kV switching station next to the existing Hanford (Wautoma) – Ostrander 500-kV line and loop in the Hanford-Ostrander line into the new switching station.
- Add terminals at Big Eddy and John Day to terminate the new lines.

Preliminary Alternatives

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit.
- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit and building a third 20-mile single-circuit 500-kV line between John Day and Big Eddy.

Analysis

No preferred alternative is proposed at this time. The project may be returned to the Technical Review Committee for consideration in 2003 following further analysis.

Energization Date: **Spring 2006**
Estimated Cost: **$70-90M**

Appendix D - Economic Analysis

The analysis used for projects G10 and G12 was conducted using Excel spreadsheet calculations. The following indicators of economic performance were computed:

- Repayment time (years from in service date)
- Net Present Value
- Benefit to Cost Ratio

The basic economic assumptions used were as follows:

Discount Rate		9.00%
Inflation Rate		2.64%
BPA Financing Rate		6.75%
O&M Escalation		0.00%
BPA Rate Escalation		0.00%
O&M Actual		2.64%
BPA Rate Actual		2.64%

The high discount rate of 9% favors projects with a faster payback period. A lower discount rate would increase benefit/cost ratio for projects G10 and G12. The treasury borrowing rate of 6.75% represents recent historical BPA borrowing.

Net Present Value and Benefit to Cost were computed using a substation equipment service life of 34 years[1] since both projects G10 and G12 have major substation components.

Capital cost expenditures were distributed over the expected year of obligation over the construction period.

BPA transmission revenues were reckoned at the rate of $1.013 $/kW-mo (12.156 $/kW-year).

Projects G10 and G12 assume that 75% of the load increase is transmission revenue producing. Assuming 50% revenue producing reduces the benefit to cost ratios by about 1/3.

Typical operations and maintenance costs are used.[1]

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[1] Annual Financial Requirements for Bonneville Power Administration Transmission System and revised Operation and Maintenance Tables, Larry Davidson, March 31, 2000.

Table D-1. Cost Stream and Economic Parameters

Discount Rate		9.00%	(Not used for payback studies)
Inflation Rate		2.64%	
BPA Financing Rate		6.75%	
O&M Escalation		0.00%	
BPA Rate Escalation		0.00%	
O&M Actual		2.64%	
BPA Rate Actual		2.64%	

	$/kw-mo.	$/kw-yr.
Rate 1	1.013	12.156
Rate 2	1.013	12.156
Rate 3	1.013	12.156

Project G10 Larry Stadler Alternative		Repayment (years)	B/C	In Service	Cost (loaded) ($M)	2002 ($M)	2003 ($M)	2004 ($M)	Distributed Capital Cost 2005 ($M)	2006 ($M)	2007 ($M)	2008 ($M)	2009 ($M)	2010 ($M)	2011 ($M)	2012 ($M)
Pearl Transformer	1	6	2.7	2003	9	1	8									
Sherwood Transformer	2	14	0.9	2003	25	2	23									
McLoughlin Transformer	3	25	0.6	2003	36	2	34									
	1a	8	2.3	2003	9	1	8									

Project G12 Julius Horvath Alternative		Repayment (years)	B/C		Cost (loaded) ($M)	2002 ($M)	2003 ($M)	2004 ($M)	Distributed Capital Cost 2005 ($M)	2006 ($M)	2007 ($M)	2008 ($M)	2009 ($M)	2010 ($M)	2011 ($M)	2012 ($M)
Shelton Transformer	1	20	0.7	2006	26					24.1	1.6					
Olympia Transformer	2	19	0.8	2006	26					21.3			1.6			3
6.5% discount rate	1a	20	0.7	2006	26					24.1	1.6					
0.09% load growth	1b	31	0.4	2006	26					24.1	1.6					
10% cost increase	1c	22	0.7	2006	28					26.51	1.76					

Table D-2. System Loading Information Used in Economic Analysis

	Notes	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
G10														
Limit	500/230 Bank	3923	3923	3923	3923	3923	3923	3923	3923	3923	3923	3923	3923	3923
Load														
Extra Heavy Winter	75.00	3848	3923	3998	4073	4148	4223	4298	4373	4448	4523	4598	4673	4748
Benefit														
Total			0	75	150	225	300	375	450	525	600	675	750	825
G10			0	75	150	225	300	300	300	300	300	300	300	300
G14 or equivalent		0	0	0	0	0	0	75	150	225	300	375	450	525

Next bank needed approximately 2016 when bank loading reaches 900 MW
Incremental benefit assigned to grid improvement G14 when grid becomes limiting extending to bank limit at 900 MW (1300 MVA)

	Notes	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
G12														
Summer Limit	N-2 DBL Ckt					600	600	600	600	600	600	600	600	600
Winter Limit	N-2 DBL Ckt					800	800	800	800	800	800	800	800	800
Winter	500/230 Bank or 230 line					1352	1352	1352	1352	1352	1352	1352	1352	1352
Load	Growth Rate													
Summer	12.33		589	601	614	626	638	651	663	675	688	700	712	725
Normal Winter	26.00		1171	1197	1223	1249	1275	1301	1327	1353	1379	1405	1431	1457
Extra Heavy Winter	29.50		1367	1397	1426	1456	1485	1515	1544	1574	1603	1633	1662	1692
Benefit														
Summer (N-2 line outage)						26	38	51	63	75	88	100	112	125
Normal Winter (N-2 line outage)						449	475	501	527	553	579	605	631	657
Normal Winter (bank/line outage)						0	0	0	0	1	27	53	79	105
Ex Heavy Winter (bank/line outage)						104	133	163	192	222	251	281	310	340
Alternative 1	Good to 2013					449	475	501	527	553	579	605	605	605
Alternative 2	Good to 2007					449	449	449	449	449	449	449	449	449

Table D-2. System Loading Information Used in Economic Analysis

2015
3923
4823
900
300
600

2015
600
800
1352
737
1483
1721
137
683
131
369
605
449

Table D-3. Project G10 Calculations Worksheet

Larry Stadler **G10**

Creditable Transmission Use (All numbers in MW)

Option	Service	Rate	Factor	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1	Load Service	12.156	0.75	0	0	75	150	225	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Load Service	12.156	0.75	0	0	75	150	225	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Load Service	12.156	0.75	0	0	75	150	225	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1a	Load Service	12.156	0.75	0	0	37.5	75	113	150	188	225	263	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Load Service	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Load Service	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Calculation of Revenues

Option				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1				0	0	0.74	1.52	2.34	3.2	3.28	3.37	3.46	3.55	3.64	3.74	3.84	3.94	4.04	4.15	4.26	4.37	4.49	4.61	4.73	4.85	4.98	5.11	5.25	12.4	12.7
2				0	0	0.74	1.52	2.34	3.2	3.28	3.37	3.46	3.55	3.64	3.74	3.84	3.94	4.04	4.15	4.26	4.37	4.49	4.61	4.73	4.85	4.98	5.11	5.25	12.4	12.7
3				0	0	0.74	1.52	2.34	3.2	3.28	3.37	3.46	3.55	3.64	3.74	3.84	3.94	4.04	4.15	4.26	4.37	4.49	4.61	4.73	4.85	4.98	5.11	5.25	12.4	12.7
1a				0	0	0.37	0.76	1.17	1.6	2.05	2.53	3.03	3.55	3.64	3.74	3.84	3.94	4.04	4.15	4.26	4.37	4.49	4.61	4.73	4.85	4.98	5.11	5.25	12.4	12.7
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Calculation O&M Cost (All numbers in actual $M)

G	O&M	2001		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1	0.119	$M/year				0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.2	0.2	0.21	0.21	0.22	0.22	0.23	0.54	0.55
2	0.170	$M/year				0.18	0.19	0.19	0.2	0.2	0.21	0.22	0.22	0.23	0.23	0.24	0.25	0.25	0.26	0.27	0.27	0.28	0.29	0.29	0.3	0.31	0.32	0.33	0.77	0.79
3	0.291	$M/year				0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.4	0.41	0.42	0.43	0.44	0.45	0.46	0.48	0.49	0.5	0.52	0.53	0.54	0.56	1.32	1.35
1a	0.119	$M/year				0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.2	0.2	0.21	0.21	0.22	0.22	0.23	0.54	0.55
	0.000	$M/year				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0.000	$M/year				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Calculation Financing Cost (All numbers in actual $M)

G				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1				0	0.07	0.61	0.61	0.56	0.45	0.27	0.08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2				0	0.14	1.66	1.74	1.77	1.74	1.65	1.56	1.45	1.33	1.19	1.04	0.88	0.7	0.49	0.27	0.03	0	0	0	0	0	0	0	0	0	0
3				0	0.14	2.44	2.58	2.67	2.71	2.7	2.69	2.67	2.64	2.6	2.56	2.5	2.44	2.37	2.28	2.19	2.08	1.96	1.82	1.66	1.49	1.3	1.08	0.85	0	0
1a				0	0.07	0.61	0.64	0.64	0.61	0.55	0.46	0.33	0.16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D-3. Project G10 Calculations Worksheet

Annual Net Revenue ($M) [Revenue minus O&M and financing cost]

Option				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1				0.0	-0.1	0.0	0.8	1.6	2.6	2.9	3.1	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.8	4.9	5.0	11.9	12.2
2				0.0	-0.1	-1.1	-0.4	0.4	1.3	1.4	1.6	1.8	2.0	2.2	2.5	2.7	3.0	3.3	3.6	4.0	4.1	4.2	4.3	4.4	4.6	4.7	4.8	4.9	11.6	11.9
3				0.0	-0.1	-2.0	-1.4	-0.7	0.1	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.1	1.2	1.4	1.6	1.8	2.1	2.3	2.6	2.8	3.2	3.5	3.8	11.1	11.4
1a				0.0	-0.1	-0.4	0.0	0.4	0.8	1.4	1.9	2.5	3.2	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.8	4.9	5.0	11.9	12.2
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Paydown of Indebtedness

Option	Cost ($M)			2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1	9			1	9	9	8	7	4	1	-2	-5	-9	-12	-16	-19	-23	-27	-31	-35	-39	-44	-48	-52	-57	-62	-67	-72	-338	-350
2	25			2	25	26	26	26	25	23	21	20	18	15	13	10	7	4	0	-4	-8	-12	-16	-21	-25	-30	-35	-40	-300	-312
3	36			2	36	38	40	40	40	40	39	39	39	38	37	36	35	34	32	31	29	27	25	22	19	16	13	9	-239	-250
1a	9			1	9	9	9	9	8	7	5	2	-1	-4	-8	-12	-15	-19	-23	-27	-31	-36	-40	-45	-49	-54	-59	-64	-330	-342
	0			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Fraction of Debt Remaining

Option				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1				0.11	1.01	1.01	0.92	0.74	0.45	0.13																				
2				0.08	1.01	1.05	1.07	1.05	1.00	0.94	0.88	0.80	0.72	0.63	0.53	0.42	0.30	0.16	0.02											
3				0.06	1.00	1.06	1.10	1.12	1.11	1.11	1.10	1.09	1.07	1.05	1.03	1.00	0.97	0.94	0.90	0.86	0.80	0.75	0.68	0.61	0.53	0.45	0.35	0.24		
1a				0.11	1.01	1.05	1.05	1.01	0.91	0.76	0.55	0.27																		

Project Capital Cost Stream

Project				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1			9	1	8	0	0	0	0	0	0	0	0	0
2			25	2	23	0	0	0	0	0	0	0	0	0
3			36	2	34	0	0	0	0	0	0	0	0	0
1a			9	1	8	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0	0	0

Table D-3. Project G10 Calculations Worksheet

Annual Operations and Maintenance Costs

	Rate	Unit	Life (yr)	1	2	3	1a		
500 Line Miles			65			9			
500 Line Maintenance	$ 2,610	per mile		$ -	$ -	$ 23,490	$ -	$ -	$ -
230 Line Miles			65						
230 Line Maintenance	$ 2,225	per mile		$ -	$ -	$ -	$ -	$ -	$ -
500 Terminal Positions			34	1	3	6	1		
500 Terminal	$ 25,666	Terminal		$ 25,666	$ 76,998	$ 153,996	$ 25,666	$ -	$ -
230 Terminal Positions			34	1	1	4	1		
230 Terminal	$ 6,624	Terminal		$ 6,624	$ 6,624	$ 26,496	$ 6,624	$ -	$ -
Series Compensation	$ 0.03036	Per Kvar	34						
500/230 Transformer	$ 86,637	3P Bank	34	$ 86,637	$ 86,637	$ 86,637	$ 86,637		
230/115 Transformer	$ 33,601	3P Bank	34						
Total			34	$ 118,927	$ 170,259	$ 290,619	$ 118,927	$ -	$ -

Present Value $M)

Project	Revenue	Costs	Net PV	B/C	In Service	Life
1	30.8	11.2	19.6	2.75	2003	2037
2	30.8	32.6	(1.8)	0.95	2003	2037
3	30.8	54.4	(23.7)	0.57	2003	2037
1a	26.9	11.9	15.0	2.26	2003	2037
	0.0	0.0	0.0			
	0.0	0.0	0.0			

Table D-3. Project G10 Calculations Worksheet

Pages D-4-6

Table D-4. Project G12 Calculation Worksheets

Julius Horvath G12

Creditable Transmission Use (All numbers in MW)

Option	Service	Rate	Factor	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1	Load Service	12.156	0.75	0	0	0	0	0	26	52	78	104	130	156	182	208	234	260	286	312	338	338	338	338	338	338	338	338	338	338
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Load Service	12.156	0.75	0	0	0	0	0	26	52	78	104	130	156	182	208	234	260	286	312	338	338	338	338	338	338	338	338	338	338
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1a	Load Service	12.156	0.75	0	0	0	0	0	26	52	78	104	130	156	182	208	234	260	286	312	338	338	338	338	338	338	338	338	338	338
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Load Service	12.156	0.75	0	0	0	0	0	13	26	39	52	65	78	91	104	117	130	143	156	169	182	195	208	221	234	247	260	338	338
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1c	Load Service	12.156	0.75	0	0	0	0	0	26	52	78	104	130	156	182	208	234	260	286	312	338	338	338	338	338	338	338	338	338	338
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Load Service	12.156	0.75	0	0	0																								
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Calculation of Revenues

Option				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1				0	0	0	0	0	0.28	0.57	0.88	1.2	1.54	1.89	2.27	2.66	3.07	3.5	3.96	4.43	4.93	5.06	5.19	5.33	5.47	5.61	5.76	5.91	14	14.3
2				0	0	0	0	0	0.28	0.57	0.88	1.2	1.54	1.89	2.27	2.66	3.07	3.5	3.96	4.43	4.93	5.06	5.19	5.33	5.47	5.61	5.76	5.91	14	14.3
1a				0	0	0	0	0	0.28	0.57	0.88	1.2	1.54	1.89	2.27	2.66	3.07	3.5	3.96	4.43	4.93	5.06	5.19	5.33	5.47	5.61	5.76	5.91	14	14.3
1b				0	0	0	0	0	0.14	0.28	0.44	0.6	0.77	0.95	1.13	1.33	1.54	1.75	1.98	2.21	2.46	2.72	2.99	3.28	3.57	3.88	4.21	4.55	14	14.3
1c				0	0	0	0	0	0.28	0.57	0.88	1.2	1.54	1.89	2.27	2.66	3.07	3.5	3.96	4.43	4.93	5.06	5.19	5.33	5.47	5.61	5.76	5.91	14	14.3
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Calculation O&M Cost (All numbers in actual $M)

G	O&M	2001		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1	0.137	$M/year							0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.2	0.2	0.21	0.21	0.22	0.22	0.23	0.24	0.24	0.25	0.26	0.26	0.62	0.64
2	0.131	$M/year							0.15	0.16	0.16	0.17	0.17	0.17	0.18	0.18	0.19	0.19	0.2	0.2	0.21	0.22	0.22	0.23	0.23	0.24	0.25	0.25	0.59	0.61
1a	0.137	$M/year							0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.2	0.2	0.21	0.21	0.22	0.22	0.23	0.24	0.24	0.25	0.26	0.26	0.62	0.64
1b	0.137	$M/year							0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.2	0.2	0.21	0.21	0.22	0.22	0.23	0.24	0.24	0.25	0.26	0.26	0.62	0.64
1c	0.137	$M/year							0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.2	0.2	0.21	0.21	0.22	0.22	0.23	0.24	0.24	0.25	0.26	0.26	0.62	0.64
	0.000	$M/year																	0	0	0	0	0	0	0	0	0	0	0	0

Calculation Financing Cost (All numbers in actual $M)

G				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1				0	0	0	0	0	1.63	1.84	1.93	2.02	2.08	2.13	2.16	2.17	2.14	2.1	2.01	1.9	1.74	1.54	1.32	1.07	0.8	0.5	0.17	0	0	0
2				0	0	0	0	0	1.44	1.53	1.6	1.77	1.82	1.85	2.06	2.06	2.03	1.97	1.88	1.76	1.59	1.38	1.15	0.89	0.6	0.29	0	0	0	0
1a				0	0	0	0	0	1.63	1.84	1.93	2.02	2.08	2.13	2.16	2.17	2.14	2.1	2.01	1.9	1.74	1.54	1.32	1.07	0.8	0.5	0.17	0	0	0
1b				0	0	0	0	0	1.63	1.85	1.96	2.08	2.19	2.3	2.4	2.5	2.59	2.67	2.75	2.81	2.87	2.91	2.94	2.95	2.95	2.92	2.87	2.8	0	0
1c				0	0	0	0	0	1.79	2.02	2.13	2.23	2.31	2.37	2.42	2.44	2.44	2.41	2.35	2.25	2.12	1.94	1.75	1.53	1.29	1.03	0.73	0.41	0	0
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D-4. Project G12 Calculation Worksheets

Annual Net Revenue ($M) [Revenue minus O&M and financing cost]

Option	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1	0.0	0.0	0.0	0.0	0.0	-1.5	-1.4	-1.2	-1.0	-0.7	-0.4	-0.1	0.3	0.7	1.2	1.7	2.3	3.0	3.3	3.6	4.0	4.4	4.9	5.3	5.6	13.3	13.7
2	0.0	0.0	0.0	0.0	0.0	-1.3	-1.1	-0.9	-0.7	-0.5	-0.1	0.0	0.4	0.9	1.3	1.9	2.5	3.1	3.5	3.8	4.2	4.6	5.1	5.5	5.7	13.4	13.7
1a	0.0	0.0	0.0	0.0	0.0	-1.5	-1.4	-1.2	-1.0	-0.7	-0.4	-0.1	0.3	0.7	1.2	1.7	2.3	3.0	3.3	3.6	4.0	4.4	4.9	5.3	5.6	13.3	13.7
1b	0.0	0.0	0.0	0.0	0.0	-1.6	-1.7	-1.7	-1.6	-1.6	-1.5	-1.5	-1.4	-1.2	-1.1	-1.0	-0.8	-0.6	-0.4	-0.2	0.1	0.4	0.7	1.1	1.5	13.3	13.7
1c	0.0	0.0	0.0	0.0	0.0	-1.7	-1.6	-1.4	-1.2	-0.9	-0.7	-0.3	0.0	0.4	0.9	1.4	2.0	2.6	2.9	3.2	3.6	3.9	4.3	4.8	5.2	13.3	13.7
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Paydown of Indebtedness

Option	Cost ($M)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1	26	0	0	0	0	24	27	29	30	31	32	32	32	32	31	30	28	26	23	20	16	12	7	3	-3	-8	-308	-321
2	26	0	0	0	0	21	23	24	26	27	27	31	31	30	29	28	26	24	20	17	13	9	4	-1	-6	-12	-312	-326
1a	26	0	0	0	0	24	27	29	30	31	32	32	32	32	31	30	28	26	23	20	16	12	7	3	-3	-8	-308	-321
1b	26	0	0	0	0	24	27	29	31	32	34	36	37	38	40	41	42	43	43	44	44	44	43	43	41	40	-239	-253
1c	28	0	0	0	0	27	30	32	33	34	35	36	36	36	36	35	33	31	29	26	23	19	15	11	6	1	-298	-312
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Fraction of Debt Remaining

Option	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1	0.00	0.00	0.00	0.00	0.94	1.06	1.11	1.16	1.20	1.23	1.25	1.25	1.24	1.21	1.16	1.09	1.00	0.89	0.76	0.62	0.46	0.29	0.10				
2	0.00	0.00	0.00	0.00	0.82	0.87	0.92	1.01	1.04	1.06	1.18	1.18	1.16	1.13	1.08	1.00	0.91	0.79	0.66	0.51	0.34	0.17					
1a	0.00	0.00	0.00	0.00	0.94	1.06	1.11	1.16	1.20	1.23	1.25	1.25	1.24	1.21	1.16	1.09	1.00	0.89	0.76	0.62	0.46	0.29	0.10				
1b	0.00	0.00	0.00	0.00	0.94	1.06	1.13	1.20	1.26	1.32	1.38	1.44	1.49	1.54	1.58	1.62	1.65	1.68	1.69	1.70	1.70	1.68	1.66	1.61	1.56		
1c	0.00	0.00	0.00	0.00	0.94	1.06	1.12	1.17	1.21	1.24	1.27	1.28	1.28	1.26	1.23	1.18	1.11	1.02	0.92	0.80	0.68	0.54	0.38	0.22	0.03		

Project Capital Cost Stream

Project		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1	26	0	0	0	0	24	2	0	0	0	0	0	0	0	0	0	0
2	23	0	0	0	0	21	0	0	2	0	0	3	0	0	0	0	0
1a	26	0	0	0	0	24	2	0	0	0	0	0	0	0	0	0	0
1b	26	0	0	0	0	24	2	0	0	0	0	0	0	0	0	0	0
1c	28	0	0	0	0	27	2	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D-4. Project G12 Calculation Worksheets

Annual Operations and Maintenance Costs

	Rate	Unit	Life (yr)	1	2	1a	1b	1c	
500 Line Miles			65	14		14	14	14	
500 Line Maintenance	$ 2,610	per mile		$ 36,540	$ -	$ 36,540	$ 36,540	$ 36,540	$ -
230 Line Miles			65	6	20	6	6	6	
230 Line Maintenance	$ 2,225	per mile		$ 13,350	$ 44,500	$ 13,350	$ 13,350	$ 13,350	$ -
500 Terminal Positions			34						
500 Terminal	$ 25,666	Terminal		$ -	$ -	$ -	$ -	$ -	$ -
230 Terminal Positions			34						
230 Terminal	$ 6,624	Terminal		$ -	$ -	$ -	$ -	$ -	$ -
Series Compensation	$ 0.03036	Per Kvar	34						
500/230 Transformer	$ 86,637	3P Bank	34	$ 86,637	$ 86,637	$ 86,637	$ 86,637	$ 86,637	
230/115 Transformer	$ 33,601	3P Bank	34						
Total			34	$ 136,527	$ 131,137	$ 136,527	$ 136,527	$ 136,527	$ -

Present Value $M)

Project	Revenue	Costs	Net PV	B/C	In Service	Life
1	21.6	29.3	(7.8)	0.74	2006	2040
2	21.6	27.2	(5.7)	0.79	2006	2040
1a	21.6	29.3	(7.8)	0.74	2006	2040
1b	14.4	34.1	(19.7)	0.42	2006	2040
1c	21.6	32.7	(11.1)	0.66	2006	2040
	0.0	0.0	0.0			

Note: To compute 1a the discount rate must be changed to 6.5% in the "Cost Information" worksheet

Table D-4. Project G12 Calculation Worksheets

Pages 7-9

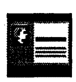
From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Monday, July 01, 2002 12:48 PM
To: Mittelstadt, Bill - TOM-PPO2-2; 'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; 'Groce, Ed'; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; 'Kinney, Scott'; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO-DITT2; 'Waples, Scott'
Cc: Haner, John - TOM-PPO2-2
Subject: RE: ITRG Draft Report

Hello again,

Please return any comments on this draft material that was submitted to you by July 10 so that the report can be finalized.

Thanks

Bill Mittelstadt



William A Mittelstadt
(E-mail)...

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Monday, June 24, 2002 8:56 AM
To: Brattebo, Scott; Carr, Geoff; CARTER, LAWRENCE; Eden, Jim; Elizeh, Edison; 'Goddard, Richard'; Groce, Ed; HORVATH, JULIUS; Johnson, Don; Juj, Hardev; KEENAN, GERALD; Kinney, Scott; KOSTEREV, DMITRY; LANDAUER, MARVIN; Leland, John; Lu, Franklin; Martinsen, John; Morris, Ken; Phillips, John; QUINATA, JOHN; Reedy, Dana; RODRIGUES, MELVIN; Rust, Jerry; RYDELL, KENDALL; Schellberg, Ron; Seabrook, Joe; SILVERSTEIN, BRIAN; STADLER, LAWRENCE; VANZANDT, VICKIE; Waples, Scott
Cc: Mittelstadt, Bill - TOM-PPO2-2; Haner, John - TOM-PPO2-2
Subject: ITRG Draft Report

Dear Technical Review Committee Participants

This year we conducted the second annual review of BPA's proposed transmission infrastructure projects. BPA offered four projects for consideration. Based on your feedback, BPA recommends that two of the projects be advanced: G10 (Portland Area Additions) for construction and G12 (Olympic Peninsula Reinforcement) for environmental review. The other two projects will be brought forward again.

Attached please find a draft report based on the format from last year. It summarizes BPA's proposals and our sense of the Committee views. We have tried to provide the additional information you requested and incorporate your feedback. Please feel free to edit the documents and return them to me. Depending on the response we can finalize the documents based on your edits, set up a conference call if further discussion is warranted, or set up a another meeting in Portland if that's what you want to do.

Our intention is to repeat the process with additional proposals next year.

I appreciate the time you have taken to provide critical feedback and I look forward to hearing from you.

Regards
Bill

<< File: William A Mittelstadt (E-mail).vcf >> << File: Cover Letter.doc >> << File: Report Draft.doc >> << File: Appendix A.doc >> << File: Appendix B.doc >> << File: Appendix C.doc >> << File: Appendix D.doc >> << File: Appendix E.doc >>

Wright, April E - KFF-2

From: Mittelstadt, Bill - TOM-PPO2-2
Sent: Tuesday, August 20, 2002 4:44 PM
To: 'Morris, Ken'; 'Juj, Hardev'; 'Leland, John'; 'Martinsen, John'; 'Waples, Scott'; 'Eden, Jim'; 'Robinett, Wayman'; 'Schellberg, Ron'
Cc: VanZandt, Vickie - TO-DITT2; Silverstein, Brian L - TOP-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2
Subject: ITRC Report for Signature

Thanks for your participation in the meeting today to complete revisions to the report and draft the transmittal cover letter. Please mail and fax a signed copy of the letter to me by Friday August 24. We do not have the attachment referenced in the cover letter in electronic form and will obtain a copy to include with the report when it is distributed.

My address and phone numbers are:

William Mittelstadt PPO2-2 TOM
Bonneville Power Administration
Parkway Plaza (Mail Center)
8100 NE Parkway
Vancouver, WA 98662
(360) 419-6672 phone
(360) 619-6945 fax

Thanks

Bill Mittelstadt

Cover Letter.doc | BPA Report.doc | Appendix A.doc | Appendix B.doc | Appendix C.doc | Appendix D.doc | Appendix D Worksheets.xls

August 20, 2002

Addressees

Subject: Infrastructure Technical Review Committee (ITRC) Report

Background

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U.S. Department of Energy, May, 2002).

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority as well as full consideration of third-party financing options. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The ITRC was formed in 2001 at the behest of some BPA customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Each year, the ITRC evaluates and works to prioritize BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. Guidelines for the review were defined in the "Agreement for Annual Review of Major BPA Transmission Investments" dated July 18, 2001 and with a update added on January 15, 2002 (attached). The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC) and the Operating Committee (OC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting a report on proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not finance the work of the ITRC.

Borrowing Authority

The committee provided its first report on August 30, 2001 with the recommendation that BPA install necessary system facilities as soon as possible. A critical first step was BPA securing additional borrowing authority. The additional borrowing authority was not approved last year. Unless additional borrowing authority is approved this fall some needed projects will be delayed, putting reliability at risk and inhibiting construction of new generation. The resulting congestion and reduced capacity margins will lead to higher prices and increased market volatility.

Projects G10-G14

Attached is the second annual report on the transmission infrastructure proposal that contains BPA's conclusions and recommendations to the review committee. The report addresses four additional projects. The committee supports BPA's findings as summarized below:

- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G11 (South Seattle Transformer) will be submitted for future review.
- Project G12 (Olympic Peninsula Reinforcement) is also important. The need date to prevent area problems for first contingency (N-1) outages is later than initially estimated based on the most recent load forecasts. Planned and controlled loss of area load is permitted under the NERC/WECC Planning Standards for the exposure to double contingency (N-2) outages provided that system cascading does not result. Opportunities for non-transmission alternatives are being pursued in parallel with the proposed transmission fix.
- Project G13 (Paul – Troutdale 500-kV Line) will continue to go through the WECC Regional Planning Process this year in expectation that it will be ready to be considered by the ITRC in 2003.
- Project G14 (Hanford-Ostrander 500 kV loop-in) requires further analysis by BPA.

Some members of the ITRC believe that projects G12 and G13 should be accelerated.

Additional Comments

- Projects reviewed in prior years will not be extensively re-reviewed unless circumstances have changed significantly. The projects are subjected to other technical reviews (i.e., TPC, NRTA, WECC) as appropriate. BPA should provide status reports to the ITRC.
- Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure firm transmission service contracts of sufficient duration and with appropriate credit provisions before proceeding with construction.

BPA is requested to continue conducting annual reviews to evaluate and prioritize proposed major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers.

Ken Morris
PacifiCorp

John Martinsen
Snohomish PUD

Wayman Robinett
Puget Sound Energy

Hardev Juj
Seattle City Light

Scott Waples
AvistaCorp

Ronald Schellberg
Idaho Power Company

John Leland
NorthWestern Energy

Jim Eden
PGE Company

cc
Infrastructure Technical Review Committee

Upgrading the Capacity and Reliability of the BPA Transmission System

Report to the Infrastructure Technical Review Committee

August 20, 2002

Table of Contents

Appendices

Please refer to the August 30, 2001 Infrastructure Review Committee report for information on the purpose of this Committee, terms of engagement and general system need. Also please refer to this report for system maps.

1.1 Background

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002). Problems with transmission in the region are manifested in several ways:

- Chronic congestion existing on a number of transmission paths requires curtailment of both firm power deliveries and economy energy.
- Continued resolution of the Western energy crisis requires development of new generating resources. The vast majority of proposed Northwest resources cannot obtain firm transmission service, or be integrated, without additional Bulk Transmission.
- It is extremely difficult to meet obligations when facilities are removed from service to conduct normal maintenance or to construct new facilities.
- While power loads have been growing steadily at 1.8% annually and the use of the transmission system is up by over 2% annually, few Bulk Transmission lines were added in the past 15 years.
- It will take much longer to site and build transmission to deliver needed new generation than it will take to build and site the generation. New transmission is needed to meet statutory, treaty and contractual obligations and comply with national and regional standards that ensure a reliable power system[1].

As the operator of three-quarters of the Bulk Transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The Infrastructure Technical Review Committee (ITRC) was formed in 2001 at the behest of some of BPA's customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Once a year, the ITRC evaluates and prioritizes BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC), Operating Committee (OC) and the Northwest Regional Transmission Association (NRTA) Planning Committee (PC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not fund the work of the ITRC.

The committee was asked to report its initial recommendations by August 30, 2001 to enable BPA to install necessary system facilities as soon as possible.

This review is the second in an annual process to coincide with BPA's annual budget cycle. It covers four projects of BPA's infrastructure proposal. Review of additional projects will be conducted in subsequent years. There are several additional parallel efforts that provide for review of proposed transmission additions. This committee's analysis and recommendations will be shared and further analyzed in the following forums.

- Northwest Power Pool (NWPP) Transmission Planning Committee
- Western Electricity Coordinating Council (WECC) Regional Planning Group
- National Environmental Policy Act (NEPA) review for individual projects

During the first part of 2002 the committee met twice to review additional infrastructure proposal developed by BPA. While some of the proposals have been under development in previous forums with outside participation, other proposals were presented for the first time. BPA conclusions and recommendations given on the following pages.

1.2 Projects Reviewed in 2002

There continues to be a compelling and immediate need to complete the projects reviewed in 2001 and to further upgrade portions of the Northwest Bulk Transmission grid. Solutions proposed by BPA in coordination with others address the identified problems. Detailed descriptions are given in Appendix C together with the economic analyses in Appendix D.

- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G11 (South Seattle Transformer) is not addressed at this time and will be submitted for future ITRC review.
- Project G12 (Olympic Peninsula Reinforcement) is also important. The need date to prevent area problems for first contingency (N-1) outages is later than initially estimated based on the most recent load forecasts. Planned curtailment of area load is permitted under the NERC/WECC Planning Standards for the exposure to double contingency (N-2) outages provided that system cascading does not result. Opportunities for non-transmission alternatives are being pursued in parallel with the continued review of the proposed transmission fix.
- Projects G13 (Paul – Troutdale 500-kV Line) and G14 (Hanford-Ostrander 500 kV loop-in) were examined on a preliminary basis. Project G13 is critical to integration of new generation in the I-5 corridor. BPA will complete details of the plan of service over the next 60 days and bring this through the WECC Regional Planning Process. In addition, coordination with PGE and PacifiCorp is required in relation to their respective transmission and generation expansion plans.
- The benefits of project G14 are not clear given proposed I5 generation development and potential higher costs to route around the Columbia Gorge Scenic Area. BPA will bring these projects forward to the committee for consideration in 2003 after further examination of alternatives and need.

Table 1. 2002 Recommended Projects

Project		Capital Cost (loaded) ($M)	Energization Date	Capacity Added MW
Portland Area Additions	G10	9	2003	300
Olympic Peninsula Reinforcement	G12	26	2005	430
Total		35		

Table 2. Drivers for 2002 Recommended Projects

	Load Service	Entitlement Return	Generation Integration	Transfers	Reliability	O&M Savings	BiOp
G10	x				x		
G12	x				x		

1.3 Projects Reviewed in 2001

- Projects evaluated in previous years should continue on the revised timetable proposed by BPA. BPA will continue to reevaluate project need and timelines, particularly for projects driven by generation integration.
- In accordance with provisions in the January 15, 2002 guidelines[2] BPA provided a status report on projects that were reviewed last year. There were no significant changes in circumstances that necessitated any of these projects be returned to the committee for a full review.
- Section 1.5 provides a status report on these projects G1-G9.

1.4 Rate and Budgetary Impacts

As started earlier, there continues to be a compelling and immediate need to continue to upgrade portions of the Northwest Bulk Transmission grid and capital to meet that need.

- Figure 1 illustrates the historical and projected transmission capital requirements forecasted by BPA over a ten-year planning horizon. The capital outlay from 2001 and beyond, including the infrastructure proposals, is well above BPA's remaining borrowing authority. Accordingly, the need still remains to increase BPA's borrowing authority for *transmission* by at least $1 billion in order to ensure that sufficient financial resources are available.
- BPA will continue to pursue and evaluate third-party financing opportunities for major new transmission projects.
- Preliminary analysis for the individual projects show that in some cases the cost will be fully recovered by increased usage and may put downward pressure on rates. Other projects that are driven by reliability needs may put upward pressure on rates. Details on the economic analysis are given in Appendix D. This report is not intended to be a rate projection.
- Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure firm transmission service contracts of sufficient duration and with appropriate credit provisions before proceeding with construction.
- Additional reinforcements by BPA and others are needed to maximize reliability and transfer capability from the proposals. Other Northwest utilities have planned and in some cases committed to transmission additions, and maximum benefits will be achieved through coordinated development.

Future reviews will be conducted annually to evaluate and prioritize BPA proposed major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers.

1.5 Status of Projects Reviewed in 2001

Projects G1-G9 reviewed in 2001 remain in the construction program but in some cases with revised energization dates, or subject to commitments from proposed generation plants. A brief status statement follows on each of these projects:

G1 Puget Sound Area Additions (Kangley – Echo Lake 500 kV Line)
The energization date for this project has set back one year to Fall 2003 to allow a full analysis of alternatives through the environmental process. Based on approval by WECC the outage of the Raver – Echo Lake and Schultz – Echo Lake lines on common rights of way has been granted an exception from two-line outage requirements and reclassified as NERC/WECC Category D (exploratory). The Snoking 500/230 kV transformer energization has also been delayed by one year to Fall 2003.

G2 North of Hanford (Schultz – Wautoma 500 kV Line and Wautoma Substation)
This project is proceeding forward on the Fall 2004 schedule with no change in status.

G3 McNary – John Day 500 kV Line
This project is proceeding forward on the Fall 2004 schedule with financial commitments having been received from generation projects for preliminary design and environmental work.

G4 Lower Monumental – Starbuck 500 kV Line
Need for this project is presently uncertain due to delay of the Starbuck generation project. Continuation of this project will depend on resumed development of this site and agreements for financing of the transmission project.

G5 Smiths Harbor – McNary 500 kV Line
Work is proceeding on plans for construction of the substation at Smiths Harbor based on commitments from the Smiths Harbor generation project. Need for the transmission project depends on plans to move forward with the Starbuck generation project or other generation in the area.

G6 Schultz Series Capacitors
This project is proceeding ahead for completion in Fall 2003 per the original schedule.

G7 Celilo Modernization
Work is proceeding on this project with the expected energization revised from Fall 2003 to Summer 2004.

G8 Monroe – Echo Lake 500 kV Line
Non-transmission solutions are being reviewed by BPA as possible alternatives for this project scheduled for Fall 2005.

G9 Bell – Coulee 500 kV Line
This project, which is intended to increase capacity across the West of Hatwai bottleneck, is on schedule for Fall 2004 energization as reported in last year's report. Since that time,

agreement has been reached on additional Phase 1 facilities (many of which were included on the list of potential Phase 2 projects in the 2001 Infrastructure Technical Review Committee Report), which are presently planned for energization between 2003 and 2007. These facilities and modifications, which will be constructed/implemented by the Avista Corporation, include the following:

- Benewah-Shawnee 230 kV Line.
- Dry Creek 230 kV Switching Station.
- Beacon-Rathdrum Double Circuit 230 kV Line.
- Increase operating limits on Hatwai-Lolo 230 kV Line.
- Increase operating limits on Hatwai-North Lewiston 230 kV Line.
- Increase operating limits on Dry Creek-North Lewiston 230 kV Line.
- Install 230 kV shunt capacitors at Benewah (200 MVAR).
- Install 230 kV shunt capacitors at Dry Creek (200 MVAR).

All of the facilities listed above will be taken through the WECC Regional Planning Process. Since the Bell-Coulee 500 kV line has already been through the process, it is expected that this will be an abbreviated process with comments only for the additional facilities. Any additions or changes to the above list of projects will be identified through the Regional Planning Process. The complete slate of Phase I facilities reinforcing the West of Hatwai Path including the Coulee – Bell 500 kV line will then be taken through the WECC Path Rating Process. Additional (West of Hatwai Phase II) facilities, which may be necessary in the Northern Idaho / Western Montana area will be identified in a follow up effort.

1.6 Glossary of Acronyms and Terms

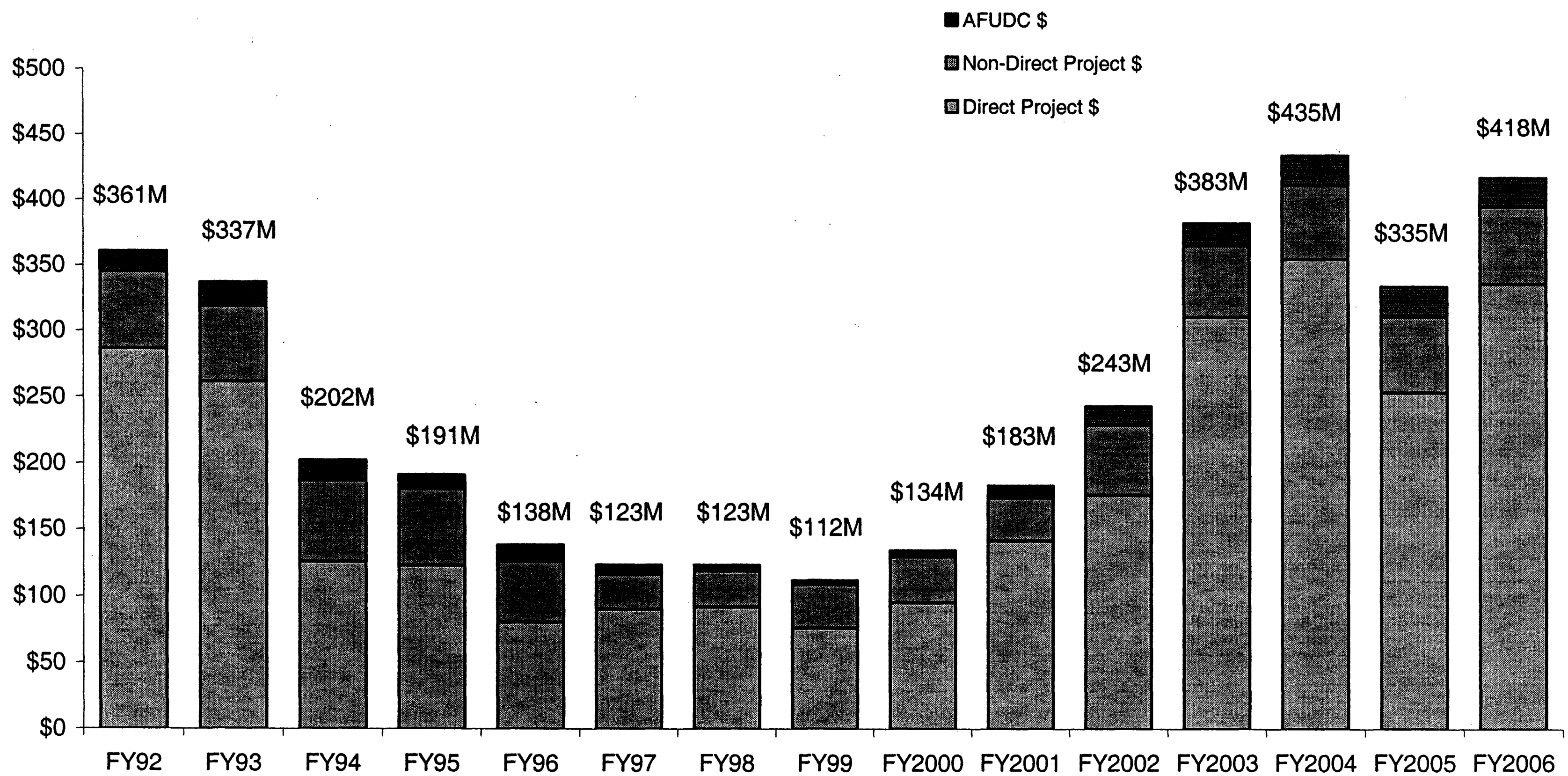
BiOp	Biological Opinion
MW	A unit of power. One MW would serve approximately 700 homes.
NRTA	Northwest Regional Transmission Association
NWPP	Northwest Power Pool
RTO	Regional Transmission Organization
WECC	Western Electricity Coordinating Council

Bulk Transmission – Transmission lines that serve as the backbone of the grid, typically operated at voltages of 230-kV and above.

1.7 References

[1] "NERC/WECC Planning Standards, Board of Trustees approved April 18, 2002.
[2] "Annual BPA Transmission Infrastructure Review," January 15, 2002.

Figure 1. TBL Capital Projects Historical & Future Trend



Appendix A – Participants

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Appendix B –Project Schedules

Project		Energization
Kangley - Echo Lake 500 kV line	G1	Fall 2003[1]
Schultz - Wautoma 500 kV line	G2	Fall 2004
McNary - John Day 500 kV line	G3	Fall 2004
Lo Monumental - Starbuck 500 kV line	G4	Fall 2004[2]
Smiths Harbor - McNary 500 kV line	G5	Fall 2004[2]
Schultz series capacitors	G6	Fall 2003
Celilo Modernization	G7	Summer 2004[1]
Monroe - Echo Lake 500 kV line	G8	Fall 2005
Bell - Coulee 500 kV line	G9	Fall 2004
Pearl Transformer	G10	Fall 2003
South Seattle Transformer	G11	Fall 2004[2,3]
Olympic Pennsula Reinforcement	G12	Fall 2006[1,2]
Paul - Troutdale 500 kV line	G13	Fall 2005[3]
Hanford - Ostrander loop-in	G14	Spring 2005[2,3]

Notes:
1 Denotes change from September, 2001 report
2 Energization may change depending on need.
3 To be submitted for future ITRC review.

Appendix C – Project Summaries

G10. Portland Area Additions (Pearl 500/230 kV Transformer)

Background
The Portland area is currently served by four 500/230 kV transformers: Troutdale on the east side, McLoughlin in SE Portland, Pearl in SW Portland and Keeler on the west side. This project is another phase of reinforcing the load serving capability from the bulk transmission system into the greater Portland area. Earlier reinforcements included adding a new 230 kV double-circuit line between Pearl and PGE's Sherwood substation.

Addition of the 2nd transformer at Pearl will require extension of both the 500 kV and the 230 kV buses. These extensions are within the existing Pearl substation.

Limiting Outages Addressed
Existing Pearl 500/230 kV Transformer

Benefit – Load Area Service
This project will increase the load carrying capability into the greater Portland area. Without this project it would be necessary to trip off load in the Portland area to relieve overloads during abnormal cold winter peaks for an outage of the existing Pearl transformer.

Business Case
This project provides the capacity to carry additional Portland area load increasing at the rate of 75 MW per year from 2004 though 2007. Beyond that date it will provide load serving benefit to the capacity of the bank following a suitable plan to address the Big Eddy – Ostrander 500 kV line outage. For the purpose of this analysis the benefit stream is limited to 300 MW for the period beyond 2007. In the Table below, Alternative 1 is the preferred plan. Alternatives 2-5 are described on the next page and on the following table is the financial analysis for alternatives 1-3.

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV	Rev/C	Repayment Years	In Service	Life
1	30.8	11.2	19.6	2.75	6	2003	2037
2	30.8	32.6	(1.8)	0.95	14	2003	2037
3	30.8	54.4	(23.7)	0.57	25	2003	2037
1a (0.9%)	26.9	11.9	15.0	2.26	8	2003	2037

Risk Factors
The following table qualitatively addresses various risk factors:

Factor	Risk	Factor	Risk
Cost	Invoiced	Delivery on time	In inventory
Siting/ROW	Existing site	Funding	Available
Load Growth	See sensitivity 1a	Discount Rate	Not considered

The proposed site has space reserved for the transformer addition. Since this does not involve work outside the substation there are no environmental risks. The Revenue/Cost ratio remains favorable with half the of the projected load growth (1a). Accordingly, this is considered to be a very low risk project.

Project Description (Alternative 1)
This project adds a 2nd 500/230 kV transformer at the existing Pearl Substation. The new transformer will be 3 single-phase units (433 MVA each). The new bank will be equipped with a 9 step LTC and a tertiary for station service. One 500 kV breaker and one 230 kV breaker will be added. The 500 kV and 230 kV buses will be extended.

Alternatives Considered

2. Install a 500/230 kV transformer at PGE's Sherwood Substation. This location would be higher cost, require additional property and would be difficult to site. It was considered in the past, but the decision was made to increase the 230 kV capacity between Pearl and Sherwood.
3. Install a 500/230 kV transformer at McLoughlin Substation.
4. Curtail load in the event of a transformer outage (Do Nothing).
5. Non-transmission alternatives.

Alternatives #2 and #3
Alternatives 2 and 3 listed above have capital costs of $24.5 M and $36 M, respectively as compared to $9 M for alternative 1.

Do-Nothing Alternative (#4)
The "no build" alternative represents the risk of load interruption for a first contingency 500/230 transformer outage at any of the four following locations: Keeler; Pearl; McLoughlin; Troutdale. Load interrupted ranges from 75 MW in 2004 to 900 MW in 2015. Based on a single phase transformer outage failure rate of once per 100 years the outage mean time between failure (MTBF) is estimated as follows:

P(no outage) = (1-1/100)^(4 banks*3 transformers/bank)
P(no outage) = 0.886
P(outage) = 1-0.886 = 0.114
MTBF = 1/0.114 = 8.8 years

While the revenues for the do-nothing alternative can be assumed to be the same assuming load can be carried under the no-outage condition, the societal cost of a bank outage would be significant. Assuming that load is curtailed to the outage limit for a period of one week until a new transformer unit is installed the present worth societal cost over ten years of service is estimated to be about $4.9 M. This is calculated using the above MTBF estimate, the following load interruption cost figures inflated yearly by 2.64% and assuming the system exposure is 8 hours/day for two months/year.

Load Type	Composition	$/kWHr (2002)
Residential	50%	$1.66
Commercial	30%	$18.50
Industrial	20%	$27.56

Non-Transmission Alternatives (#5)
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and Environmental Economics, Nov. 2001 available at:

http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm.

Non-transmission alternatives can not be implemented in time to be considered a viable alternative to this project.

Analysis
BPA chose the preferred plan for the following reasons:

- Lowest cost
- Essentially no environmental impact (existing site)
- Favorable Revenue/Cost ratio (2.75)
- Favorable economics under reduced load growth rate
- Short repayment period (6 years)

Energization Date: **Fall 2003 (Preferred Alternative)**
Estimated Cost: **$9M**

G12. Olympic Peninsula Reinforcement (Paul-Shelton 500-kV line)

Background
The Olympic Peninsula area load is served from Olympia substation via 230-kV and 115-kV transmission. The major source to Olympia to serve these loads is the 500-kV transmission line from Paul substation. An outage of this 500-kV source to Olympia would result in a voltage collapse during extra heavy winter load conditions. A second 500-kV source is needed to solve the voltage collapse problem as early as 2003. A shunt capacitor group to be installed in 2003 will delay the need for this project until 2005. With this addition the Olympic Peninsula transmission system has reached the limit that can be supported by shunt capacitors. A total of 20 capacitor groups amounting to approximately 900 MVAR will have been installed.

In addition, a double-line outage of the 230-kV double-circuit line from Olympia to Shelton or a breaker failure at Olympia will result in a total loss of the Olympic Peninsula during normal winter load. The proposed reinforcement will solve both the N-1 and N-2 problems and reinforce the Olympic Peninsula region.

Limiting Outages Addressed
- Olympia 500/230-kV transformer
- Paul-Olympia 500-kV line
- Olympia-Shelton 230-kV double line
- Olympia 230-kV breaker failure

Benefit - Load Area Service
This project will prevent these outages from impacting service to the Olympic Peninsula by providing a second source of power to the Peninsula from Paul Substation. This project will also increase the load service capability to the Olympic Peninsula under non-outage conditions as well as mitigate or delay other system upgrades that would be needed in the future if this project were not built.

Business Case
This project provides the capacity to carry additional projected normal winter load in the Olympic Peninsula area in compliance with NERC/WECC Planning Standards for Category A-C outages. For the purpose of this analysis revenues are based on 1.8% load growth corresponding to 26 MW/year reaching a project limit of 338 MW in 2019. In the Table below, Alternative 1 is the proposed plan and Alternative 2 would involve moving the 500/230-kV transformer to Olympia (see below). Alternatives 1a-1c are sensitivity studies discussed under "Risk."

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV	Rev/C	Repayment Years	In Service	Life
1	21.6	29.3	(7.8)	0.74	20	2006	2040
1a	35.7	35.5	0.2	1.00	20	2006	2040
1b	14.4	34.1	(19.7)	0.42	31	2006	2040
1c	21.6	32.7	(11.1)	0.66	22	2006	2040
2	21.6	27.2	(5.7)	0.79	19	2006	2040

Risk
The following table qualitatively addresses various risk factors. Three are identified for evaluation.

Factor	Risk	Factor	Risk
Cost	**See sensitivity 1c**	Delivery on time	Routine purchases
Siting/ROW	Existing site/ROW	Funding	Available
Load Growth	**See sensitivity 1b**	Discount Rate	**See sensitivity 1a**

Sensitivity 1a – This case determines what discount rate is needed to achieve a Revenue/Cost ratio of 1.0. This is achieved by a discount rate of 6.5%, giving an equivalent rate of return on investment of 6.5% over the 34 year life of the project.
Sensitivity 1b – In this case the load growth rate of 1.8% is cut in half to 0.9%. This reduces the Revenue/Cost ratio from 0.74 to 0.42 and extends the repayment period from 20 years to 31 years.
Sensitivity 1c – This case represents an increase in project cost of 10%. The Revenue/Cost ratio for this case dropped from 0.74 to 0.66 and the repayment period increased from 20 years to 22 years.

Project Description

- Build approximately 13.8 miles of 500-kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to the Shelton 500 kV yard. The line will be routed on the existing Olympia-Shelton right of way. Cut the Paul-Satsop 500 kV line at corridor intersection and connect the Paul end to new 500 kV line to Shelton.
- Remove Olympia-Shelton 115 kV line #1 from Olympia to Dayton Tap.
- Construct a 500 kV yard approximately 1 mile south of the existing Shelton substation, move Satsop 500/230 kV transformer to this location and tie it to Shelton 230 kV bus via 1 mile long 230 kV line.
- Build approximately 6 miles of new 230 kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to Olympia substation. Connect this new line to Satsop end of cut Paul-Satsop 500 kV line.

Alternatives Considered

2. Move Satsop 500/230 kV transformer to Olympia substation and terminate the Paul-Satsop 500 kV line at Olympia.
3. No build alternative
4. Non-transmission alternatives

Alternative #2
Alternative #2 listed above has approximately the same capital cost as alternative #1.

Do-Nothing Alternative (#3)
(a) The following information applies to voltage collapse for N-1 contingencies for extra heavy winter if the transmission system is not reinforced:

- A 2 year MTBF for N-1 Paul-Olympia 500 kV line with average outage duration of 2.5 hours.
- A 100 year MTBF each phase of the Olympia 500/230 transformer and a 4 week replacement time. This corresponds to a bank outage probability of:

  P(outage) = 1-(1-1/100)^3 = 0.030, and a
  MTBF = 1/0.030 = 34 years.

- The required load curtailment for either outage increases by 26 MW yearly starting in 2006.

Since the outage time is quite different for the two events the societal costs are estimated separately. Voltage collapse is assumed to occur when the demand exceeds capacity following the outage by more than 100 MW. Area load is restored to the capability of the remaining system within one hour. Using the same customer outage costs as with G10 the present worth societal costs of the N-1 line outage is $1 M and the N-1 bank outage is $5.65 M for a ten year period.

(b) The following information was used to estimate the probability of loss of load for N-2 contingencies if the transmission system is not reinforced:

- 9.3 year MTBF for N-2 outage of Olympia – Shelton 230 kV lines 3 and 4. It is further assumed that one line can be restored within one hour and the second line within 24 hours.
- 0.018 breaker failures/year for each of eight breakers at Olympia. It is assumed that full service is restored within one hour by moving the affected line over to the bus tie breaker. This corresponds to a bus outage probability of

  P(outage) = 1-(1-0.018)^8 = 0.14, and a
  MTBF = 1/0.14 = 7.4 years.

Again, the societal costs of the two events are treated separately. In each case it is assumed that the entire area load will be lost due to voltage collapse for the initial period of one hour. The estimated present worth societal costs are: $5.06 M for the two-line outage and $500 K for the breaker failure outages.

Overall then the estimated present worth societal cost for a ten year period of the do-nothing alternative is approximately $15.7 M. The present value savings of a ten-year delay in the project is expected to be greater considering deferred capital, financing and O&M costs.

Non-Transmission Alternatives (#4)
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and

Environmental Economics, Nov. 2001 available at
http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm.

These measures could cost-effectively defer the need under N-1 contingencies, although they can not address the N-2 problems. BPA will further consider non-transmission alternatives before proceeding with this project. Cost information is not available at this time to allow presentation of an economic analysis.

Reliability Considerations
The NERC/WECC Planning Standards address planning requirements for the various contingencies applicable to this project. Planned loss of demand or curtailment of firm transfers is permitted for the case of the double line outage (N-2) and the stuck breaker but not for the single contingency outage (N-1). Cascading outages are not permitted. Cascading is "...the uncontrolled successive loss of system elements triggered by an incident at any location...and results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies."[1] To meet these requirements a solution must be in place not later than the time (1) the system is adversely impacted for single contingency outages or (2) cascading outages occur for the less probable breaker failure and double contingency outages. In the event that loss of demand or firm transfers are indicated than it is on a planned basis " to maintain the overall security of the interconnected transmission system." In the case of this project these contingencies will not result in cascading or impact the security of the overall system. However, the societal impact of these low likelihood events will continue to be examined as another indicator affecting project need date.

Analysis
BPA has selected a preferred transmission plan from the alternatives considered, but has elected to defer a decision on the project to allow time for further development of the non-transmission alternative (#4) and to consider public input before proceeding.

Of the transmission alternatives considered, the preferred plan is Alternative 1 because it outperforms the Olympia option for both N-2 critical outages for essentially the same present worth cost without O&M expenses included. O&M costs would be higher for the Olympia option based on the amount of extra equipment that would be needed at the Olympia substation. The Olympia option would require major 230 kV work at the Olympia substation, including expansion of the 230 kV yard. Land would also have to be purchased around the 500 kV yard for 230 kV line routing into the 230 kV bus. Some of the line routing into the 230 kV bus may not even be physically possible based on current line routing, tower and road locations, land needs and right-of-way widths. The Shelton option has 8 MW less losses than the Olympia option based on 1170 MW of load, which is equivalent to normal winter load in 2002-03. These losses will increase with increases in load. The Shelton option would leave the system better prepared for the future.

BPA will further consider non-transmission alternatives before proceeding with this project.

Energization Date: Fall 2006
Estimated Cost: $23-26 M

G13. Paul – Troutdale 500-kV Line

Background

The existing I-5 corridor transmission system is limited to:

- 2400 MW North of Allston by a double Paul – Allston 500-kV line outage
- 1650 MW South of Allston by the Allston – Keeler 500-kV line outage

With new generation projects proposed in the area, the existing system is not adequate to provide transmission service to most new generating projects on a firm basis, likely resulting in generation curtailments.

At present, the double Paul – Allston 500-kV line outage requires 2850 MW generation dropping and opening of both Chehalis – Longview 230-kV line that run in parallel to the Paul – Allston line. This sectionalizing removes the northern feed into Portland metro area, resulting in load service only from the east side through Ostrander. Sectionalizing greatly reduces reactive margins in the system, which will become a limiting factor as load grows in Portland area. Sectionalizing was also shown to degrade transient stability performance.

Currently, the Allston – Keeler 500-kV line outage requires generation dropping up to 2850 MW to prevent thermal overloads. Historic data indicates that there were 19 line outages in the past 16 years, mostly cased either by lightning hits or trees. It is very desirable to reduce generation dropping amount for a single contingency since these are more frequent than multi-contingency outages.

This project is being taken through the WECC Regional Planning process.

Limiting Outages Addressed

Paul – Allston 500-kV double line
Allston – Keeler 500-kV line
Keeler – Pearl 500-kV line
Keeler breaker failure

Benefits

Table 1. Generation projects proposed in the area affecting transmission needs:

Project	Capacity	Energization	North of Allston	South of Allston
Napavine[1]	600	11/1/03	More stress	More stress
Grays Harbor I[1]	630	6/1/03	More stress	More stress
Longview – Enron	300	7/1/03	Less stress	More stress
Mint Farm[1]	280	5/1/03	Less stress	More stress
Summit	530	11/1/03	Less stress	More stress
Big Hanaford	250	In Service	More stress	More stress
Port Westward	650	12/31/03	Less stress	More stress
Centralia efficiency	70	In Service	More stress	More stress
Grays Harbor II	630	11/1/04	More stress	More stress

[1] Under construction

It is evident that new generation will greatly increase stress on the constrained I-5 paths. The existing system is not adequate to provide transmission service to most generating projects on a firm basis, and with several projects already in construction generation curtailments can be expected without this project. The new 500-kV line is expected to provide firm transmission rights for the proposed projects in the area.

A. Transfer Increase

It is expected that South of Allston limit will increase from 1650 MW to 2,700 – 2,900 MW. The new line will eliminate or greatly reduce the need for generation dropping for N-1 outages and allow time to ramp down generation. Upgrades of parallel 115-kV and 230-kV lines may be required to get the full capacity.

B. Load Service in Winter Conditions

Studies are under way.

Business Case
This project is driven by requests for long-term firm transmission by new generation and imports. Parties requesting transmission would be expected to fund the upgrade consistent with FERC policy.

Risk
The risk associated with this project is small because the generators will be expected to finance the transmission investment and/or commit to long-term transmission service.

Project Description
At present time, the plan of service is not fully defined. Two conceptual options have been considered and studied for electrical performance. Alternative #1 includes a 500-kV line from near Longview to Troutdale, and alternative #2 is a 500-kV line from near Longview to Pearl.

Analysis
No preferred alternative is proposed at this time. The project will be returned to the Technical Review Committee for consideration in 2003 following the WECC Regional Planning Process.

Energization Date: **Fall 2005**
Estimated Cost: **$117-155 M**

G14. North of John Day/Portland Area Reinforcement – (Loop the Hanford-Ostrander 500-kV line into Big Eddy)

Background

The proposed new generation additions around the McNary area along with the new McNary-John Day 500-kV line will increase the stress across the North of John Day and the flow between John Day and Big Eddy. This project will relieve some of the North of John Day constraint and reinforce the transmission between John Day and Big Eddy. In addition, this project will also reinforce the bulk load serving capability into the greater Portland area. During abnormal cold weather, an outage of the Bid Eddy-Ostrander 500-kV line results in voltage collapse in the Portland area. This Project will in effect create a second Big Eddy – Ostrander 500-kV line and increase the load serving capability to the Portland area.

Limiting Outages Addressed

Ashe-Marion/Slatt-Buckley 500-kV double line loss (summer)
John Day-Big Eddy 500-kV double line loss (summer)
Slatt 500-kV breaker failures (summer)
Big Eddy-Ostrander 500-kV line (winter)
Pearl 500-kV breaker failures (winter)

Benefit – Congestion Relief and Load Area Support

This project will increase the North of John Day capability by approximately 250-300 MW and increase the capability between John Day and Big Eddy by approximately 600-700 MW. This project also reinforces the bulk grid to serve greater Portland area load and eliminate the need for building second Big Eddy-Ostrander 500-kV line.

Business Case

The primary drivers of this project is North to South network transfers and provide additional network capacity for service to the Portland area load. The estimated cost recovery of this project at current rates and for the alternatives considered is over 35 years. In view of the long payback period lower cost alternatives or deferral will be considered.

Risk

The benefit ascribed to this project for the Portland area load is related to the timing of the Paul – Troutdale project which in part serves this need. The portion of benefits ascribed to intertie support will be beneficial at the time the project goes into service but is not sufficient alone to ensure full cost recovery. Risk that costs will not be recovered for this project as proposed at this point is high.

Project Description

- This project consists of constructing approximately 16.5 miles of 500-kV double circuit line to the Columbia River crossing and approximately 18 miles of single circuit 500-kV line to Big Eddy and 2 miles of line to John Day.

- Develop a new 500-kV switching station next to the existing Hanford (Wautoma) – Ostrander 500-kV line and loop in the Hanford-Ostrander line into the new switching station.
- Add terminals at Big Eddy and John Day to terminate the new lines.

Preliminary Alternatives

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit.
- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit and building a third 20-mile single-circuit 500-kV line between John Day and Big Eddy.

Analysis
No preferred alternative is proposed at this time. The project may be returned to the Technical Review Committee for consideration in 2003 following further analysis.

Energization Date: Spring 2006
Estimated Cost: $70-90M

Table D-3. Project G10 Calculations Worksheet

Larry Stadler G10

Creditable Transmission Use (All numbers in MW)

Option	Service	Rate	Factor	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1	Load Service	12.156	0.75	0	0	75	150	225	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Load Service	12.156	0.75	0	0	75	150	225	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Load Service	12.156	0.75	0	0	75	150	225	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1a	Load Service	12.156	0.75	0	0	37.5	75	113	150	188	225	263	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Load Service	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Load Service	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Generation	12.156	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other	12.156	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Calculation of Revenues

Option				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1				0	0	0.74	1.52	2.34	3.2	3.28	3.37	3.46	3.55	3.64	3.74	3.84	3.94	4.04	4.15	4.26	4.37	4.49	4.61	4.73	4.85	4.98	5.11	5.25	12.4	12.7
2				0	0	0.74	1.52	2.34	3.2	3.28	3.37	3.46	3.55	3.64	3.74	3.84	3.94	4.04	4.15	4.26	4.37	4.49	4.61	4.73	4.85	4.98	5.11	5.25	12.4	12.7
3				0	0	0.74	1.52	2.34	3.2	3.28	3.37	3.46	3.55	3.64	3.74	3.84	3.94	4.04	4.15	4.26	4.37	4.49	4.61	4.73	4.85	4.98	5.11	5.25	12.4	12.7
1a				0	0	0.37	0.76	1.17	1.6	2.05	2.53	3.03	3.55	3.64	3.74	3.84	3.94	4.04	4.15	4.26	4.37	4.49	4.61	4.73	4.85	4.98	5.11	5.25	12.4	12.7
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Calculation O&M Cost (All numbers in actual $M)

G	O&M	2001		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1	0.119	$M/year				0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.2	0.2	0.21	0.21	0.22	0.22	0.23	0.54	0.55
2	0.170	$M/year				0.18	0.19	0.19	0.2	0.2	0.21	0.22	0.22	0.23	0.23	0.24	0.25	0.25	0.26	0.27	0.27	0.28	0.29	0.29	0.3	0.31	0.32	0.33	0.77	0.79
3	0.291	$M/year				0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.4	0.41	0.42	0.43	0.44	0.45	0.46	0.48	0.49	0.5	0.52	0.53	0.54	0.56	1.32	1.35
1a	0.119	$M/year				0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.2	0.2	0.21	0.21	0.22	0.22	0.23	0.54	0.55
	0.000	$M/year				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0.000	$M/year				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Calculation Financing Cost (All numbers in actual $M)

G				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1				0	0.07	0.61	0.61	0.56	0.45	0.27	0.08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2				0	0.14	1.66	1.74	1.77	1.74	1.65	1.56	1.45	1.33	1.19	1.04	0.88	0.7	0.49	0.27	0.03	0	0	0	0	0	0	0	0	0	0
3				0	0.14	2.44	2.58	2.67	2.71	2.7	2.69	2.67	2.64	2.6	2.56	2.5	2.44	2.37	2.28	2.19	2.08	1.96	1.82	1.66	1.49	1.3	1.08	0.85	0	0
1a				0	0.07	0.61	0.64	0.64	0.61	0.55	0.46	0.33	0.16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D-3. Project G10 Calculations Worksheet

Annual Net Revenue ($M) [Revenue minus O&M and financing cost]

Option				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1				0.0	-0.1	0.0	0.8	1.6	2.6	2.9	3.1	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.8	4.9	5.0	11.9	12.2
2				0.0	-0.1	-1.1	-0.4	0.4	1.3	1.4	1.6	1.8	2.0	2.2	2.5	2.7	3.0	3.3	3.6	4.0	4.1	4.2	4.3	4.4	4.6	4.7	4.8	4.9	11.6	11.9
3				0.0	-0.1	-2.0	-1.4	-0.7	0.1	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.1	1.2	1.4	1.6	1.8	2.1	2.3	2.6	2.8	3.2	3.5	3.8	11.1	11.4
1a				0.0	-0.1	-0.4	0.0	0.4	0.8	1.4	1.9	2.5	3.2	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.8	4.9	5.0	11.9	12.2
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Paydown of Indebtedness

Option	Cost ($M)			2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1	9			1	9	9	8	7	4	1	-2	-5	-9	-12	-16	-19	-23	-27	-31	-35	-39	-44	-48	-52	-57	-62	-67	-72	-338	-350
2	25			2	25	26	26	26	25	23	21	20	18	15	13	10	7	4	0	-4	-8	-12	-16	-21	-25	-30	-35	-40	-300	-312
3	36			2	36	38	40	40	40	40	39	39	39	38	37	36	35	34	32	31	29	27	25	22	19	16	13	9	-239	-250
1a	9			1	9	9	9	9	8	7	5	2	-1	-4	-8	-12	-15	-19	-23	-27	-31	-36	-40	-45	-49	-54	-59	-64	-330	-342
	0			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Fraction of Debt Remaining

Option				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2059	2060
1				0.11	1.01	1.01	0.92	0.74	0.45	0.13																				
2				0.08	1.01	1.05	1.07	1.05	1.00	0.94	0.88	0.80	0.72	0.63	0.53	0.42	0.30	0.16	0.02											
3				0.06	1.00	1.06	1.10	1.12	1.11	1.11	1.10	1.09	1.07	1.05	1.03	1.00	0.97	0.94	0.90	0.86	0.80	0.75	0.68	0.61	0.53	0.45	0.35	0.24		
1a				0.11	1.01	1.05	1.05	1.01	0.91	0.76	0.55	0.27																		

Project Capital Cost Stream

Project				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1			9	1	8	0	0	0	0	0	0	0	0	0
2			25	2	23	0	0	0	0	0	0	0	0	0
3			36	2	34	0	0	0	0	0	0	0	0	0
1a			9	1	8	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0	0	0

Table D-3. Project G10 Calculations Worksheet

Annual Operations and Maintenance Costs

	Rate	Unit	Life (yr)	1	2	3	1a		
500 Line Miles			65			9			
500 Line Maintenance	$ 2,610	per mile		$ -	$ -	$ 23,490	$ -	$ -	$ -
230 Line Miles			65						
230 Line Maintenance	$ 2,225	per mile		$ -	$ -	$ -	$ -	$ -	$ -
500 Terminal Positions			34	1	3	6	1		
500 Terminal	$ 25,666	Terminal		$ 25,666	$ 76,998	$ 153,996	$ 25,666	$ -	$ -
230 Terminal Positions			34	1	1	4	1		
230 Terminal	$ 6,624	Terminal		$ 6,624	$ 6,624	$ 26,496	$ 6,624	$ -	$ -
Series Compensation	$ 0.03036	Per Kvar	34						
500/230 Transformer	$ 86,637	3P Bank	34	$ 86,637	$ 86,637	$ 86,637	$ 86,637		
230/115 Transformer	$ 33,601	3P Bank	34						
Total			34	$ 118,927	$ 170,259	$ 290,619	$ 118,927	$ -	$ -

Present Value $M)

Project	Revenue	Costs	Net PV	B/C	In Service	Life
1	30.8	11.2	19.6	2.75	2003	2037
2	30.8	32.6	(1.8)	0.95	2003	2037
3	30.8	54.4	(23.7)	0.57	2003	2037
1a	26.9	11.9	15.0	2.26	2003	2037
	0.0	0.0	0.0			
	0.0	0.0	0.0			

Table D-3. Project G10 Calculations Worksheet

Pages D-4-6

Appendix D - Economic Analysis

The analysis used for projects G10 and G12 was conducted using Excel spreadsheet calculations. The following indicators of economic performance were computed:

- Repayment time (years from in service date)
- Net Present Value
- Benefit to Cost Ratio

The basic economic assumptions used were as follows:

Discount Rate		9.00%
Inflation Rate		2.64%
BPA Financing Rate		6.75%
O&M Escalation		0.00%
BPA Rate Escalation		0.00%
O&M Actual		2.64%
BPA Rate Actual		2.64%

The high discount rate of 9% favors projects with a faster payback period. A lower discount rate would increase benefit/cost ratio for projects G10 and G12. The treasury borrowing rate of 6.75% represents recent historical BPA borrowing.

Net Present Value and Benefit to Cost were computed using a substation equipment service life of 34 years[1] since both projects G10 and G12 have major substation components.

Capital cost expenditures were distributed over the expected year of obligation over the construction period.

BPA transmission revenues were reckoned at the rate of $1.013 $/kW-mo (12.156 $/kW-year).

Projects G10 and G12 assume that 75% of the load increase is transmission revenue producing. Assuming 50% revenue producing reduces the benefit to cost ratios by about 1/3.

Typical operations and maintenance costs are used.[1]

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[1] Annual Financial Requirements for Bonneville Power Administration Transmission System and revised Operation and Maintenance Tables, Larry Davidson, March 31, 2000.

Wright, April E - LC-7

From: Seabrook, Joe [joe.seabrook@pse.com]
Sent: Monday, August 26, 2002 4:37 PM
To: Mittelstadt, Bill (E-mail)
Subject: FW: ITRC Report for Signature

-----Original Message-----
From: Seabrook, Joe
Sent: Monday, August 26, 2002 4:31 PM
To: Robinett, Wayman
Subject: RE: ITRC Report for Signature

Wayman,
I would request that a minor change be added to each of the attached documents. I made the change in red-line mark up format so that they can be found. The change is with respect to the G12 (Olympic Peninsula Reinforcement) project. It is to include mention of the Olympia 230 kV bus outages as resulting in voltage collapse, in addition to the double circuit loss.

Joe

Cover Letter r.doc BPA Report r.doc Appendix C r.doc

-----Original Message-----
From: Robinett, Wayman
Sent: Monday, August 26, 2002 12:07 PM
To: Seabrook, Joe; Phillips, John M -GEN04W; Reese, Chris
Subject: FW: ITRC Report for Signature

Wayman Robinett
Puget Sound Energy
Office 1-360-571-7680
Pager 1-888-444-6792
Fax 1-360-573-7743
Cell 1-206-604-5270

From: Mittelstadt, Bill - TOM-PPO2-2 [SMTP:wmittelstadt@bpa.gov] <mailto:[SMTP:wmittelstadt@bpa.gov]>
Sent: Tuesday, August 20, 2002 4:44 PM
To: 'Morris, Ken'; 'Juj, Hardev'; 'Leland, John'; 'Martinsen, John'; 'Waples, Scott'; 'Eden, Jim'; 'Robinett, Wayman'; 'Schellberg, Ron'
Cc: VanZandt, Vickie - TO; Silverstein, Brian L - TOP-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2
Subject: ITRC Report for Signature

Thanks for your participation in the meeting today to complete revisions to the report and draft the transmittal cover letter. Please mail and fax a signed copy of the letter to me by Friday August 24. We do not have the attachment referenced in the cover letter in electronic form and will obtain a copy to include with the report when it is distributed.

My address and phone numbers are:

William Mittelstadt PPO2-2 TOM
Bonneville Power Administration
Parkway Plaza (Mail Center)
8100 NE Parkway
Vancouver, WA 98662
(360) 419-6672 phone
(360) 619-6945 fax

Thanks

Bill Mittelstadt

<<Cover Letter.doc>> <<BPA Report.doc>> <<Appendix A.doc>> <<Appendix B.doc>> <<Appendix C.doc>> <<Appendix D.doc>> <<Appendix D Worksheets.xls>> << File: Cover Letter.doc >> << File: BPA Report.doc >> << File: Appendix A.doc >> << File: Appendix B.doc >> << File: Appendix C.doc >> << File: Appendix D.doc >> << File: Appendix D Worksheets.xls >>

August 20, 2002

Addressees

Subject: Infrastructure Technical Review Committee (ITRC) Report

Background

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U.S. Department of Energy, May, 2002).

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority as well as full consideration of third-party financing options. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The ITRC was formed in 2001 at the behest of some BPA customers to support BPA's efforts to secure funding for BPA's infrastructure proposals.. Each year, the ITRC evaluates and works to prioritize BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. Guidelines for the review were defined in the "Agreement for Annual Review of Major BPA Transmission Investments" dated July 18, 2001 and with a update added on January 15, 2002 (attached). The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC) and the Operating Committee (OC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting a report on proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not finance the work of the ITRC.

Borrowing Authority

The committee provided its first report on August 30, 2001 with the recommendation that BPA install necessary system facilities as soon as possible. A critical first step was BPA securing additional borrowing authority. The additional borrowing authority was not approved last year. Unless additional borrowing authority is approved this fall some needed projects will be delayed, putting reliability at risk and inhibiting construction of new generation. The resulting congestion and reduced capacity margins will lead to higher prices and increased market volatility.

Projects G10-G14

Attached is the second annual report on the transmission infrastructure proposal that contains BPA's conclusions and recommendations to the review committee. The report addresses four additional projects. The committee supports BPA's findings as summarized below:

- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G11 (South Seattle Transformer) will be submitted for future review.
- Project G12 (Olympic Peninsula Reinforcement) is also important. The need date to prevent area problems for first contingency (N-1) outages is later than initially estimated based on the most recent load forecasts. Planned and controlled loss of area load is permitted under the NERC/WECC Planning Standards for the exposure to double contingency (N-2) and bus outages provided that system cascading does not result. Opportunities for non-transmission alternatives are being pursued in parallel with the proposed transmission fix.
- Project G13 (Paul – Troutdale 500-kV Line) will continue to go through the WECC Regional Planning Process this year in expectation that it will be ready to be considered by the ITRC in 2003.
- Project G14 (Hanford-Ostrander 500 kV loop-in) requires further analysis by BPA.

Some members of the ITRC believe that projects G12 and G13 should be accelerated.

Additional Comments

- Projects reviewed in prior years will not be extensively re-reviewed unless circumstances have changed significantly. The projects are subjected to other technical reviews (i.e., TPC, NRTA, WECC) as appropriate. BPA should provide status reports to the ITRC.
- Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure firm transmission service contracts of sufficient duration and with appropriate credit provisions before proceeding with construction.

BPA is requested to continue conducting annual reviews to evaluate and prioritize proposed major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers.

Ken Morris PacifiCorp	John Martinsen Snohomish PUD	Wayman Robinett Puget Sound Energy
Hardev Juj Seattle City Light	Scott Waples AvistaCorp	Ronald Schellberg Idaho Power Company
John Leland NorthWestern Energy	Jim Eden PGE Company	

cc
Infrastructure Technical Review Committee

Upgrading the Capacity and Reliability of the BPA Transmission System

Report to the Infrastructure Technical Review Committee

August 20, 2002

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Appendices

Please refer to the August 30, 2001 Infrastructure Review Committee report for information on the purpose of this Committee, terms of engagement and general system need. Also please refer to this report for system maps.

1.1 Background

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002). Problems with transmission in the region are manifested in several ways:

- Chronic congestion existing on a number of transmission paths requires curtailment of both firm power deliveries and economy energy.
- Continued resolution of the Western energy crisis requires development of new generating resources. The vast majority of proposed Northwest resources cannot obtain firm transmission service, or be integrated, without additional Bulk Transmission.
- It is extremely difficult to meet obligations when facilities are removed from service to conduct normal maintenance or to construct new facilities.
- While power loads have been growing steadily at 1.8% annually and the use of the transmission system is up by over 2% annually, few Bulk Transmission lines were added in the past 15 years.
- It will take much longer to site and build transmission to deliver needed new generation than it will take to build and site the generation. New transmission is needed to meet statutory, treaty and contractual obligations and comply with national and regional standards that ensure a reliable power system[1].

As the operator of three-quarters of the Bulk Transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The Infrastructure Technical Review Committee (ITRC) was formed in 2001 at the behest of some of BPA's customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Once a year, the ITRC evaluates and prioritizes BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC), Operating Committee (OC) and the Northwest Regional Transmission Association (NRTA) Planning Committee (PC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not fund the work of the ITRC.

The committee was asked to report its initial recommendations by August 30, 2001 to enable BPA to install necessary system facilities as soon as possible.

This review is the second in an annual process to coincide with BPA's annual budget cycle. It covers four projects of BPA's infrastructure proposal. Review of additional projects will be conducted in subsequent years. There are several additional parallel efforts that provide for review of proposed transmission additions. This committee's analysis and recommendations will be shared and further analyzed in the following forums.

- Northwest Power Pool (NWPP) Transmission Planning Committee
- Western Electricity Coordinating Council (WECC) Regional Planning Group
- National Environmental Policy Act (NEPA) review for individual projects

During the first part of 2002 the committee met twice to review additional infrastructure proposal developed by BPA. While some of the proposals have been under development in previous forums with outside participation, other proposals were presented for the first time. BPA conclusions and recommendations given on the following pages.

1.2 Projects Reviewed in 2002

There continues to be a compelling and immediate need to complete the projects reviewed in 2001 and to further upgrade portions of the Northwest Bulk Transmission grid. Solutions proposed by BPA in coordination with others address the identified problems. Detailed descriptions are given in Appendix C together with the economic analyses in Appendix D.

- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G11 (South Seattle Transformer) is not addressed at this time and will be submitted for future ITRC review.
- Project G12 (Olympic Peninsula Reinforcement) is also important. The need date to prevent area problems for first contingency (N-1) outages is later than initially estimated based on the most recent load forecasts. Planned curtailment of area load is permitted under the NERC/WECC Planning Standards for the exposure to double contingency (N-2) and bus outages provided that system cascading does not result. Opportunities for non-transmission alternatives are being pursued in parallel with the continued review of the proposed transmission fix.
- Projects G13 (Paul – Troutdale 500-kV Line) and G14 (Hanford-Ostrander 500 kV loop-in) were examined on a preliminary basis. Project G13 is critical to integration of new generation in the I-5 corridor. BPA will complete details of the plan of service over the next 60 days and bring this through the WECC Regional Planning Process. In addition, coordination with PGE and PacifiCorp is required in relation to their respective transmission and generation expansion plans.
- The benefits of project G14 are not clear given proposed I5 generation development and potential higher costs to route around the Columbia Gorge Scenic Area. BPA will bring these projects forward to the committee for consideration in 2003 after further examination of alternatives and need.

Table 1. 2002 Recommended Projects

Project		Capital Cost (loaded) ($M)	Energization Date	Capacity Added MW
Portland Area Additions	G10	9	2003	300
Olympic Peninsula Reinforcement	G12	26	2005	430
Total		35		

Table 2. Drivers for 2002 Recommended Projects

	Load Service	Entitlement Return	Generation Integration	Transfers	Reliability	O&M Savings	BiOp
G10	x				x		
G12	x				x		

1.3 Projects Reviewed in 2001

- Projects evaluated in previous years should continue on the revised timetable proposed by BPA. BPA will continue to reevaluate project need and timelines, particularly for projects driven by generation integration.
- In accordance with provisions in the January 15, 2002 guidelines[2] BPA provided a status report on projects that were reviewed last year. There were no significant changes in circumstances that necessitated any of these projects be returned to the committee for a full review.
- Section 1.5 provides a status report on these projects G1-G9.

1.4 Rate and Budgetary Impacts

As started earlier, there continues to be a compelling and immediate need to continue to upgrade portions of the Northwest Bulk Transmission grid and capital to meet that need.

- Figure 1 illustrates the historical and projected transmission capital requirements forecasted by BPA over a ten-year planning horizon. The capital outlay from 2001 and beyond, including the infrastructure proposals, is well above BPA's remaining borrowing authority. Accordingly, the need still remains to increase BPA's borrowing authority for *transmission* by at least $1 billion in order to ensure that sufficient financial resources are available.
- BPA will continue to pursue and evaluate third-party financing opportunities for major new transmission projects.
- Preliminary analysis for the individual projects show that in some cases the cost will be fully recovered by increased usage and may put downward pressure on rates. Other projects that are driven by reliability needs may put upward pressure on rates. Details on the economic analysis are given in Appendix D. This report is not intended to be a rate projection.
- Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure firm transmission service contracts of sufficient duration and with appropriate credit provisions before proceeding with construction.
- Additional reinforcements by BPA and others are needed to maximize reliability and transfer capability from the proposals. Other Northwest utilities have planned and in some cases committed to transmission additions, and maximum benefits will be achieved through coordinated development.

Future reviews will be conducted annually to evaluate and prioritize BPA proposed major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers.

1.5 Status of Projects Reviewed in 2001

Projects G1-G9 reviewed in 2001 remain in the construction program but in some cases with revised energization dates, or subject to commitments from proposed generation plants. A brief status statement follows on each of these projects:

G1 Puget Sound Area Additions (Kangley – Echo Lake 500 kV Line)
The energization date for this project has set back one year to Fall 2003 to allow a full analysis of alternatives through the environmental process. Based on approval by WECC the outage of the Raver – Echo Lake and Schultz – Echo Lake lines on common rights of way has been granted an exception from two-line outage requirements and reclassified as NERC/WECC Category D (exploratory). The Snoking 500/230 kV transformer energization has also been delayed by one year to Fall 2003.

G2 North of Hanford (Schultz – Wautoma 500 kV Line and Wautoma Substation)
This project is proceeding forward on the Fall 2004 schedule with no change in status.

G3 McNary – John Day 500 kV Line
This project is proceeding forward on the Fall 2004 schedule with financial commitments having been received from generation projects for preliminary design and environmental work.

G4 Lower Monumental – Starbuck 500 kV Line
Need for this project is presently uncertain due to delay of the Starbuck generation project. Continuation of this project will depend on resumed development of this site and agreements for financing of the transmission project.

G5 Smiths Harbor – McNary 500 kV Line
Work is proceeding on plans for construction of the substation at Smiths Harbor based on commitments from the Smiths Harbor generation project. Need for the transmission project depends on plans to move forward with the Starbuck generation project or other generation in the area.

G6 Schultz Series Capacitors
This project is proceeding ahead for completion in Fall 2003 per the original schedule.

G7 Celilo Modernization
Work is proceeding on this project with the expected energization revised from Fall 2003 to Summer 2004.

G8 Monroe – Echo Lake 500 kV Line
Non-transmission solutions are being reviewed by BPA as possible alternatives for this project scheduled for Fall 2005.

G9 Bell – Coulee 500 kV Line
This project, which is intended to increase capacity across the West of Hatwai bottleneck, is on schedule for Fall 2004 energization as reported in last year's report. Since that time,

agreement has been reached on additional Phase 1 facilities (many of which were included on the list of potential Phase 2 projects in the 2001 Infrastructure Technical Review Committee Report), which are presently planned for energization between 2003 and 2007. These facilities and modifications, which will be constructed/implemented by the Avista Corporation, include the following:

- Benewah-Shawnee 230 kV Line.
- Dry Creek 230 kV Switching Station.
- Beacon-Rathdrum Double Circuit 230 kV Line.
- Increase operating limits on Hatwai-Lolo 230 kV Line.
- Increase operating limits on Hatwai-North Lewiston 230 kV Line.
- Increase operating limits on Dry Creek-North Lewiston 230 kV Line.
- Install 230 kV shunt capacitors at Benewah (200 MVAR).
- Install 230 kV shunt capacitors at Dry Creek (200 MVAR).

All of the facilities listed above will be taken through the WECC Regional Planning Process. Since the Bell-Coulee 500 kV line has already been through the process, it is expected that this will be an abbreviated process with comments only for the additional facilities. Any additions or changes to the above list of projects will be identified through the Regional Planning Process. The complete slate of Phase I facilities reinforcing the West of Hatwai Path including the Coulee – Bell 500 kV line will then be taken through the WECC Path Rating Process. Additional (West of Hatwai Phase II) facilities, which may be necessary in the Northern Idaho / Western Montana area will be identified in a follow up effort.

1.6 Glossary of Acronyms and Terms

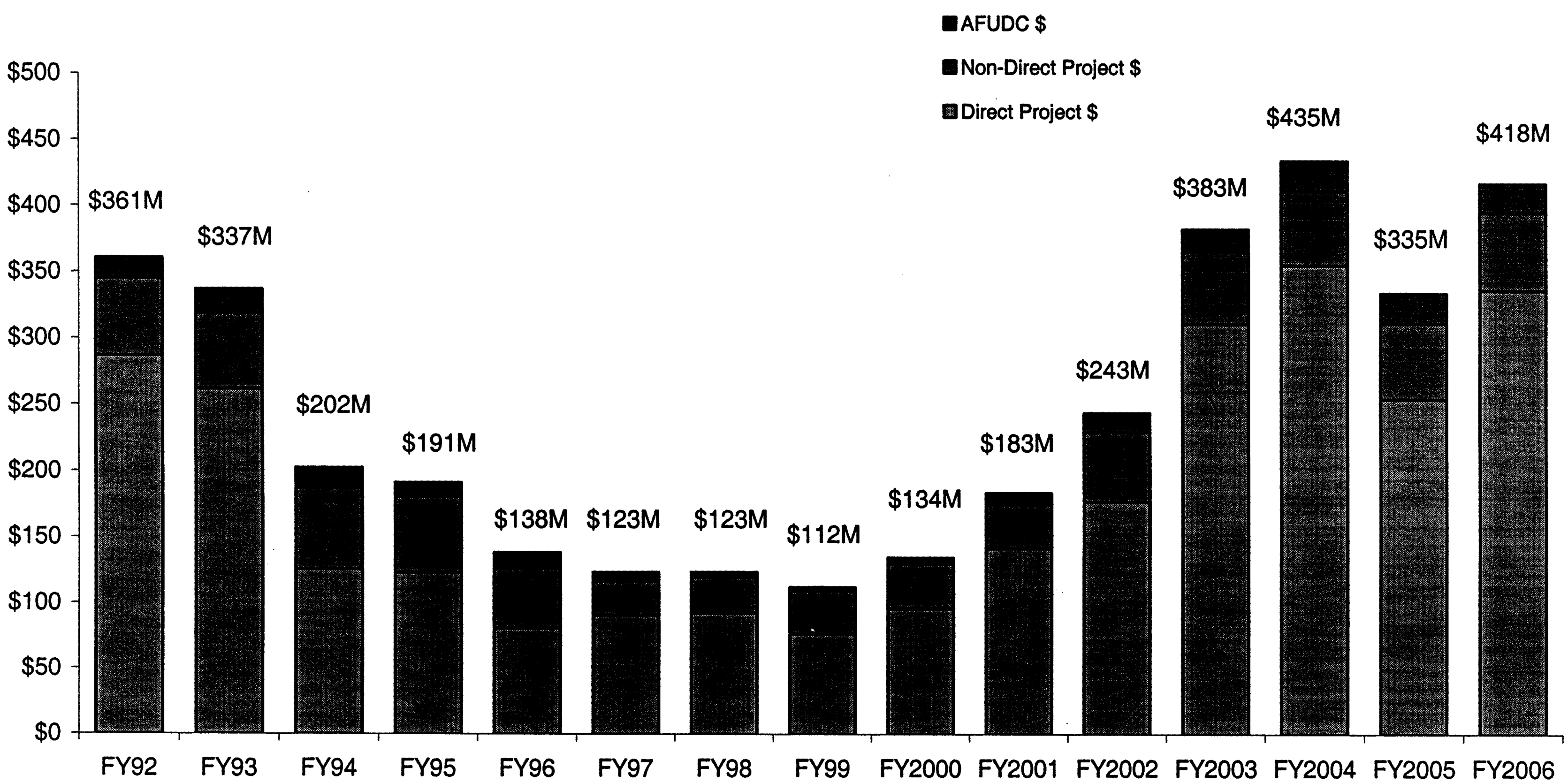
BiOp	Biological Opinion
MW	A unit of power. One MW would serve approximately 700 homes.
NRTA	Northwest Regional Transmission Association
NWPP	Northwest Power Pool
RTO	Regional Transmission Organization
WECC	Western Electricity Coordinating Council

Bulk Transmission – Transmission lines that serve as the backbone of the grid, typically operated at voltages of 230-kV and above.

1.7 References

[1] "NERC/WECC Planning Standards, Board of Trustees approved April 18, 2002.
[2] "Annual BPA Transmission Infrastructure Review," January 15, 2002.

Figure 1. TBL Capital Projects Historical & Future Trend



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~~1.~~Appendix C – Project Summaries

G10. Portland Area Additions (Pearl 500/230 kV Transformer)

Background

The Portland area is currently served by four 500/230 kV transformers: Troutdale on the east side, McLoughlin in SE Portland, Pearl in SW Portland and Keeler on the west side. This project is another phase of reinforcing the load serving capability from the bulk transmission system into the greater Portland area. Earlier reinforcements included adding a new 230 kV double-circuit line between Pearl and PGE's Sherwood substation.

Addition of the 2nd transformer at Pearl will require extension of both the 500 kV and the 230 kV buses. These extensions are within the existing Pearl substation.

Limiting Outages Addressed

Existing Pearl 500/230 kV Transformer

Benefit – Load Area Service

This project will increase the load carrying capability into the greater Portland area. Without this project it would be necessary to trip off load in the Portland area to relieve overloads during abnormal cold winter peaks for an outage of the existing Pearl transformer.

Business Case

This project provides the capacity to carry additional Portland area load increasing at the rate of 75 MW per year from 2004 though 2007. Beyond that date it will provide load serving benefit to the capacity of the bank following a suitable plan to address the Big Eddy – Ostrander 500 kV line outage. For the purpose of this analysis the benefit stream is limited to 300 MW for the period beyond 2007. In the Table below, Alternative 1 is the preferred plan. Alternatives 2-5 are described on the next page and on the following table is the financial analysis for alternatives 1-3.

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV	Rev/C	Repayment Years	In Service	Life
1	30.8	11.2	19.6	2.75	6	2003	2037
2	30.8	32.6	(1.8)	0.95	14	2003	2037
3	30.8	54.4	(23.7)	0.57	25	2003	2037
1a (0.9%)	26.9	11.9	15.0	2.26	8	2003	2037

Risk Factors

The following table qualitatively addresses various risk factors:

Factor	Risk	Factor	Risk
Cost	Invoiced	Delivery on time	In inventory
Siting/ROW	Existing site	Funding	Available
Load Growth	See sensitivity 1a	Discount Rate	Not considered

The proposed site has space reserved for the transformer addition. Since this does not involve work outside the substation there are no environmental risks. The Revenue/Cost ratio remains favorable with half the of the projected load growth (1a). Accordingly, this is considered to be a very low risk project.

Project Description (Alternative 1)
This project adds a 2nd 500/230 kV transformer at the existing Pearl Substation. The new transformer will be 3 single-phase units (433 MVA each). The new bank will be equipped with a 9 step LTC and a tertiary for station service. One 500 kV breaker and one 230 kV breaker will be added. The 500 kV and 230 kV buses will be extended.

Alternatives Considered

2. Install a 500/230 kV transformer at PGE's Sherwood Substation. This location would be higher cost, require additional property and would be difficult to site. It was considered in the past, but the decision was made to increase the 230 kV capacity between Pearl and Sherwood.
3. Install a 500/230 kV transformer at McLoughlin Substation.
4. Curtail load in the event of a transformer outage (Do Nothing).
5. Non-transmission alternatives.

Alternatives #2 and #3
Alternatives 2 and 3 listed above have capital costs of $24.5 M and $36 M, respectively as compared to $9 M for alternative 1.

Do-Nothing Alternative (#4)
The "no build" alternative represents the risk of load interruption for a first contingency 500/230 transformer outage at any of the four following locations: Keeler; Pearl; McLoughlin; Troutdale. Load interrupted ranges from 75 MW in 2004 to 900 MW in 2015. Based on a single phase transformer outage failure rate of once per 100 years the outage mean time between failure (MTBF) is estimated as follows:

> P(no outage) = (1-1/100)^(4 banks*3 transformers/bank)
> P(no outage) = 0.886
> P(outage) = 1-0.886 = 0.114
> MTBF = 1/0.114 = 8.8 years

While the revenues for the do-nothing alternative can be assumed to be the same assuming load can be carried under the no-outage condition, the societal cost of a bank outage would be significant. Assuming that load is curtailed to the outage limit for a period of one week until a new transformer unit is installed the present worth societal cost over ten years of service is estimated to be about $4.9 M. This is calculated using the above MTBF estimate, the following load interruption cost figures inflated yearly by 2.64% and assuming the system exposure is 8 hours/day for two months/year.

Load Type	Composition	$/kWHr (2002)
Residential	50%	$1.66
Commercial	30%	$18.50
Industrial	20%	$27.56

Non-Transmission Alternatives (#5)

As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and Environmental Economics, Nov. 2001 available at:

http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm.

Non-transmission alternatives can not be implemented in time to be considered a viable alternative to this project.

Analysis

BPA chose the preferred plan for the following reasons:

- Lowest cost
- Essentially no environmental impact (existing site)
- Favorable Revenue/Cost ratio (2.75)
- Favorable economics under reduced load growth rate
- Short repayment period (6 years)

Energization Date: **Fall 2003 (Preferred Alternative)**
Estimated Cost: **$9M**

G12. Olympic Peninsula Reinforcement (Paul-Shelton 500-kV line)

Background
The Olympic Peninsula area load is served from Olympia substation via 230-kV and 115-kV transmission. The major source to Olympia to serve these loads is the 500-kV transmission line from Paul substation. An outage of this 500-kV source to Olympia would result in a voltage collapse during extra heavy winter load conditions. A second 500-kV source is needed to solve the voltage collapse problem as early as 2003. A shunt capacitor group to be installed in 2003 will delay the need for this project until 2005. With this addition the Olympic Peninsula transmission system has reached the limit that can be supported by shunt capacitors. A total of 20 capacitor groups amounting to approximately 900 MVAR will have been installed.

In addition, a double-line outage of the 230-kV double-circuit line from Olympia to Shelton or a breaker failure at Olympia will result in a total loss of the Olympic Peninsula during normal winter load. The proposed reinforcement will solve both the N-1 and N-2 problems and reinforce the Olympic Peninsula region.

Limiting Outages Addressed
- Olympia 500/230-kV transformer
- Paul-Olympia 500-kV line
- Olympia-Shelton 230-kV double line
- Olympia 230-kV West or East bus outage
- Olympia 230-kV breaker failure

Benefit - Load Area Service
This project will prevent these outages from impacting service to the Olympic Peninsula by providing a second source of power to the Peninsula from Paul Substation. This project will also increase the load service capability to the Olympic Peninsula under non-outage conditions as well as mitigate or delay other system upgrades that would be needed in the future if this project were not built.

Business Case
This project provides the capacity to carry additional projected normal winter load in the Olympic Peninsula area in compliance with NERC/WECC Planning Standards for Category A-C outages. For the purpose of this analysis revenues are based on 1.8% load growth corresponding to 26 MW/year reaching a project limit of 338 MW in 2019. In the Table below, Alternative 1 is the proposed plan and Alternative 2 would involve moving the 500/230-kV transformer to Olympia (see below). Alternatives 1a-1c are sensitivity studies discussed under "Risk."

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV	Rev/C	Repayment Years	In Service	Life
1	21.6	29.3	(7.8)	0.74	20	2006	2040
1a	35.7	35.5	0.2	1.00	20	2006	2040
1b	14.4	34.1	(19.7)	0.42	31	2006	2040
1c	21.6	32.7	(11.1)	0.66	22	2006	2040

2	21.6	27.2	(5.7)	0.79	19	2006	2040

Risk

The following table qualitatively addresses various risk factors. Three are identified for evaluation.

Factor	Risk	Factor	Risk
Cost	**See sensitivity 1c**	Delivery on time	Routine purchases
Siting/ROW	Existing site/ROW	Funding	Available
Load Growth	**See sensitivity 1b**	Discount Rate	**See sensitivity 1a**

Sensitivity 1a – This case determines what discount rate is needed to achieve a Revenue/Cost ratio of 1.0. This is achieved by a discount rate of 6.5%, giving an equivalent rate of return on investment of 6.5% over the 34 year life of the project.
Sensitivity 1b – In this case the load growth rate of 1.8% is cut in half to 0.9%. This reduces the Revenue/Cost ratio from 0.74 to 0.42 and extends the repayment period from 20 years to 31 years.
Sensitivity 1c – This case represents an increase in project cost of 10%. The Revenue/Cost ratio for this case dropped from 0.74 to 0.66 and the repayment period increased from 20 years to 22 years.

Project Description

- Build approximately 13.8 miles of 500-kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to the Shelton 500 kV yard. The line will be routed on the existing Olympia-Shelton right of way. Cut the Paul-Satsop 500 kV line at corridor intersection and connect the Paul end to new 500 kV line to Shelton.
- Remove Olympia-Shelton 115 kV line #1 from Olympia to Dayton Tap.
- Construct a 500 kV yard approximately 1 mile south of the existing Shelton substation, move Satsop 500/230 kV transformer to this location and tie it to Shelton 230 kV bus via 1 mile long 230 kV line.
- Build approximately 6 miles of new 230 kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to Olympia substation. Connect this new line to Satsop end of cut Paul-Satsop 500 kV line.

Alternatives Considered

2. Move Satsop 500/230 kV transformer to Olympia substation and terminate the Paul-Satsop 500 kV line at Olympia.
3. No build alternative
4. Non-transmission alternatives

Alternative #2

Alternative #2 listed above has approximately the same capital cost as alternative #1.

Do-Nothing Alternative (#3)

(a) The following information applies to voltage collapse for N-1 contingencies for extra heavy winter if the transmission system is not reinforced:

- ~~1.~~ A 2 year MTBF for N-1 Paul-Olympia 500 kV line with average outage duration of 2.5 hours.
- ~~1.~~ A 100 year MTBF each phase of the Olympia 500/230 transformer and a 4 week replacement time. This corresponds to a bank outage probability of:

  ~~1.~~P(outage) = 1-(1-1/100)^3 = 0.030, and a
  ~~1.~~MTBF = 1/0.030 = 34 years.

- ~~1.~~ The required load curtailment for either outage increases by 26 MW yearly starting in 2006.

Since the outage time is quite different for the two events the societal costs are estimated separately. Voltage collapse is assumed to occur when the demand exceeds capacity following the outage by more than 100 MW. Area load is restored to the capability of the remaining system within one hour. Using the same customer outage costs as with G10 the present worth societal costs of the N-1 line outage is $1 M and the N-1 bank outage is $5.65 M for a ten year period.

(b) The following information was used to estimate the probability of loss of load for N-2 contingencies if the transmission system is not reinforced:

- ~~1.~~ 9.3 year MTBF for N-2 outage of Olympia – Shelton 230 kV lines 3 and 4. It is further assumed that one line can be restored within one hour and the second line within 24 hours.
- ~~1.~~ 0.018 breaker failures/year for each of eight breakers at Olympia. It is assumed that full service is restored within one hour by moving the affected line over to the bus tie breaker. This corresponds to a bus outage probability of

  ~~1.~~P(outage) = 1-(1-0.018)^8 = 0.14, and a
  ~~1.~~MTBF = 1/0.14 = 7.4 years.

Again, the societal costs of the two events are treated separately. In each case it is assumed that the entire area load will be lost due to voltage collapse for the initial period of one hour. The estimated present worth societal costs are: $5.06 M for the two-line outage and $500 K for the breaker failure outages.

Overall then the estimated present worth societal cost for a ten year period of the do-nothing alternative is approximately $15.7 M. The present value savings of a ten-year delay in the project is expected to be greater considering deferred capital, financing and O&M costs.

Non-Transmission Alternatives (#4)
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and

Environmental Economics, Nov. 2001 available at
http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm.

These measures could cost-effectively defer the need under N-1 contingencies, although they can not address the N-2 problems. BPA will further consider non-transmission alternatives before proceeding with this project. Cost information is not available at this time to allow presentation of an economic analysis.

Reliability Considerations
The NERC/WECC Planning Standards address planning requirements for the various contingencies applicable to this project. Planned loss of demand or curtailment of firm transfers is permitted for the case of the double line outage (N-2) and the stuck breaker but not for the single contingency outage (N-1). Cascading outages are not permitted. Cascading is "...the uncontrolled successive loss of system elements triggered by an incident at any location...and results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies."[1] To meet these requirements a solution must be in place not later than the time (1) the system is adversely impacted for single contingency outages or (2) cascading outages occur for the less probable breaker failure and double contingency outages. In the event that loss of demand or firm transfers are indicated than it is on a planned basis " to maintain the overall security of the interconnected transmission system." In the case of this project these contingencies will not result in cascading or impact the security of the overall system. However, the societal impact of these low likelihood events will continue to be examined as another indicator affecting project need date.

Analysis
BPA has selected a preferred transmission plan from the alternatives considered, but has elected to defer a decision on the project to allow time for further development of the non-transmission alternative (#4) and to consider public input before proceeding.

Of the transmission alternatives considered, the preferred plan is Alternative 1 because it outperforms the Olympia option for both N-2 critical outages for essentially the same present worth cost without O&M expenses included. O&M costs would be higher for the Olympia option based on the amount of extra equipment that would be needed at the Olympia substation. The Olympia option would require major 230 kV work at the Olympia substation, including expansion of the 230 kV yard. Land would also have to be purchased around the 500 kV yard for 230 kV line routing into the 230 kV bus. Some of the line routing into the 230 kV bus may not even be physically possible based on current line routing, tower and road locations, land needs and right-of-way widths. The Shelton option has 8 MW less losses than the Olympia option based on 1170 MW of load, which is equivalent to normal winter load in 2002-03. These losses will increase with increases in load. The Shelton option would leave the system better prepared for the future.

BPA will further consider non-transmission alternatives before proceeding with this project.

Energization Date: Fall 2006
Estimated Cost: $23-26 M

G13. Paul – Troutdale 500-kV Line

Background

The existing I-5 corridor transmission system is limited to:

- 2400 MW North of Allston by a double Paul – Allston 500-kV line outage
- 1650 MW South of Allston by the Allston – Keeler 500-kV line outage

With new generation projects proposed in the area, the existing system is not adequate to provide transmission service to most new generating projects on a firm basis, likely resulting in generation curtailments.

At present, the double Paul – Allston 500-kV line outage requires 2850 MW generation dropping and opening of both Chehalis – Longview 230-kV line that run in parallel to the Paul – Allston line. This sectionalizing removes the northern feed into Portland metro area, resulting in load service only from the east side through Ostrander. Sectionalizing greatly reduces reactive margins in the system, which will become a limiting factor as load grows in Portland area. Sectionalizing was also shown to degrade transient stability performance.

Currently, the Allston – Keeler 500-kV line outage requires generation dropping up to 2850 MW to prevent thermal overloads. Historic data indicates that there were 19 line outages in the past 16 years, mostly cased either by lightning hits or trees. It is very desirable to reduce generation dropping amount for a single contingency since these are more frequent than multi-contingency outages.

This project is being taken through the WECC Regional Planning process.

Limiting Outages Addressed

Paul – Allston 500-kV double line
Allston – Keeler 500-kV line
Keeler – Pearl 500-kV line
Keeler breaker failure

Benefits

Table 1. Generation projects proposed in the area affecting transmission needs:

Project	Capacity	Energization	North of Allston	South of Allston
Napavine[1]	600	11/1/03	More stress	More stress
Grays Harbor I[1]	630	6/1/03	More stress	More stress
Longview – Enron	300	7/1/03	Less stress	More stress
Mint Farm[1]	280	5/1/03	Less stress	More stress
Summit	530	11/1/03	Less stress	More stress
Big Hanaford	250	In Service	More stress	More stress
Port Westward	650	12/31/03	Less stress	More stress
Centralia efficiency	70	In Service	More stress	More stress
Grays Harbor II	630	11/1/04	More stress	More stress

[1] Under construction

It is evident that new generation will greatly increase stress on the constrained I-5 paths. The existing system is not adequate to provide transmission service to most generating projects on a firm basis, and with several projects already in construction generation curtailments can be expected without this project. The new 500-kV line is expected to provide firm transmission rights for the proposed projects in the area.

A. Transfer Increase

It is expected that South of Allston limit will increase from 1650 MW to 2,700 – 2,900 MW. The new line will eliminate or greatly reduce the need for generation dropping for N-1 outages and allow time to ramp down generation. Upgrades of parallel 115-kV and 230-kV lines may be required to get the full capacity.

B. Load Service in Winter Conditions

Studies are under way.

Business Case
This project is driven by requests for long-term firm transmission by new generation and imports. Parties requesting transmission would be expected to fund the upgrade consistent with FERC policy.

Risk
The risk associated with this project is small because the generators will be expected to finance the transmission investment and/or commit to long-term transmission service.

Project Description
At present time, the plan of service is not fully defined. Two conceptual options have been considered and studied for electrical performance. Alternative #1 includes a 500-kV line from near Longview to Troutdale, and alternative #2 is a 500-kV line from near Longview to Pearl.

Analysis
No preferred alternative is proposed at this time. The project will be returned to the Technical Review Committee for consideration in 2003 following the WECC Regional Planning Process.

Energization Date: **Fall 2005**
Estimated Cost: **$117-155 M**

G14. North of John Day/Portland Area Reinforcement – (Loop the Hanford-Ostrander 500-kV line into Big Eddy)

Background
The proposed new generation additions around the McNary area along with the new McNary-John Day 500-kV line will increase the stress across the North of John Day and the flow between John Day and Big Eddy. This project will relieve some of the North of John Day constraint and reinforce the transmission between John Day and Big Eddy. In addition, this project will also reinforce the bulk load serving capability into the greater Portland area. During abnormal cold weather, an outage of the Bid Eddy-Ostrander 500-kV line results in voltage collapse in the Portland area. This Project will in effect create a second Big Eddy – Ostrander 500-kV line and increase the load serving capability to the Portland area.

Limiting Outages Addressed
Ashe-Marion/Slatt-Buckley 500-kV double line loss (summer)
John Day-Big Eddy 500-kV double line loss (summer)
Slatt 500-kV breaker failures (summer)
Big Eddy-Ostrander 500-kV line (winter)
Pearl 500-kV breaker failures (winter)

Benefit – Congestion Relief and Load Area Support
This project will increase the North of John Day capability by approximately 250-300 MW and increase the capability between John Day and Big Eddy by approximately 600-700 MW. This project also reinforces the bulk grid to serve greater Portland area load and eliminate the need for building second Big Eddy-Ostrander 500-kV line.

Business Case
The primary drivers of this project is North to South network transfers and provide additional network capacity for service to the Portland area load. The estimated cost recovery of this project at current rates and for the alternatives considered is over 35 years. In view of the long payback period lower cost alternatives or deferral will be considered.

Risk
The benefit ascribed to this project for the Portland area load is related to the timing of the Paul – Troutdale project which in part serves this need. The portion of benefits ascribed to intertie support will be beneficial at the time the project goes into service but is not sufficient alone to ensure full cost recovery. Risk that costs will not be recovered for this project as proposed at this point is high.

Project Description

- This project consists of constructing approximately 16.5 miles of 500-kV double circuit line to the Columbia River crossing and approximately 18 miles of single circuit 500-kV line to Big Eddy and 2 miles of line to John Day.

- Develop a new 500-kV switching station next to the existing Hanford (Wautoma) – Ostrander 500-kV line and loop in the Hanford-Ostrander line into the new switching station.
- Add terminals at Big Eddy and John Day to terminate the new lines.

Preliminary Alternatives

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit.
- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit and building a third 20-mile single-circuit 500-kV line between John Day and Big Eddy.

Analysis
No preferred alternative is proposed at this time. The project may be returned to the Technical Review Committee for consideration in 2003 following further analysis.

Energization Date: Spring 2006
Estimated Cost: $70-90M

From: Phillips, John M -GEN04W [john.phillips@pse.com]
Sent: Friday, August 16, 2002 11:33 AM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Cc: Horvath, Julius G - TOP-PPO2-2; Seabrook, Joe; Robinett, Wayman
Subject: RE: ITRC Report and Meeting

Bill,

Correct. Based on HW03 power flows, it appears that without some type of controlled load shedding we currently have exposure to uncontrolled voltage collapse on the Olympic Peninsula. In addition, for the BPA Olympia West 230kV bus outage, there would be post-transient voltage deviations greater than 10% (See table W-1 in WECC guidelines) in Thurston County.

Just to clarify or position. We feel that the amount of load on the Olympic Peninsula, PSE's and BPA's, exceeds the intentions of footnote d. Our efforts here are to help build justification for not delaying the project.

Thanks,
John

Note E-Mail Address Change: john.phillips@pse.com

John Phillips
Puget Sound Energy
Location: 10608 NE 4 St, Bellevue WA
External Phone: (425) 462-3579
Internal Phone: 81-3579

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Friday, August 16, 2002 8:32 AM
To: 'Phillips, John M -GEN04W'
Cc: Horvath, Julius G - TOP-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2
Subject: RE: ITRC Report and Meeting

John

In the second comment, are you referring to footnote d?

"Depending on system design and expected sysetm impacts, the controlled interruption of electric supply to customerse (load shedding), the planned removal from service of certain generators, or the curtailment of contracted firm (non-recallable reserved) electric power transfer may be necessary to maintain the oerall security opf the interconnected transmission systems."

Bill

-----Original Message-----
From: Phillips, John M -GEN04W [mailto:john.phillips@pse.com]
Sent: Thursday, August 15, 2002 4:39 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Cc: Reese, Chris; Robinett, Wayman; RODRIGUES, MELVIN; Seabrook, Joe
Subject: RE: ITRC Report and Meeting

Bill,

PSE had two comments.

We still aren't comfortable with justification for the $1 billion figure in the report. However, if BPA feels it needs to remain in the report and the committee disagrees then it can be addressed in the cover letter.

The second item is the verbiage added to the report and appendix C regarding G-12. Justification for delaying the project are based the NERC/WECC guidelines allowing for "planned" loss of load for a level "C" outages. Per the guidelines the loss of load also needs to be controlled. Does BPA currently have in place controls to prevent a voltage collapse during heavy winter loading? If not, a proposal, such as a RAS, should be added.

Thanks,
John

Note E-Mail Address Change: john.phillips@pse.com

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-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Wednesday, August 14, 2002 8:22 AM
To: Brattebo, Scott; Carr, Geoff; CARTER, LAWRENCE; Eden, Jim; Elizeh, Edison; 'Goddard, Richard'; Groce, Ed; HORVATH, JULIUS; Johnson, Don; Juj, Hardev; KEENAN, GERALD; Kinney, Scott; KOSTEREV, DMITRY; LANDAUER, MARVIN; Leland, John; Lu, Franklin; Martinsen, John; Morris, Ken; Phillips, John; QUINATA, JOHN; Reedy, Dana; Reese, Chris; Robinett, Wayman; RODRIGUES, MELVIN; Rust, Jerry; RYDELL, KENDALL; Schellberg, Ron; Seabrook, Joe; SILVERSTEIN, BRIAN; STADLER, LAWRENCE; VANZANDT, VICKIE; Waples, Scott
Cc: Mittelstadt, Bill - TOM-PPO2-2
Subject: ITRC Report and Meeting

Per comments received during our Monday conference call I am redistributing the draft report in revisions format. Changes appear in files: "Report Draft" and "Appendix C." Additional pages are provided to Appendix D as an Excel workbook (print all worksheets).

As already noted it has been scheduled to convene the ITRC at the Portland Airport PDX conference center on Tuesday August 20 from 9 am to 2 pm to conclude any revisions to this report and conclude on the group drafted cover letter. We should plan on bringing closure to this years report at that Tuesday meeting and obtain signatures for the cover letter of those present.

If you have any further comments before that time please forward them to me.

Bill Mittelstadt

<<William A Mittelstadt (E-mail).vcf>> <<Report Draft 8~13.doc>>
<<Appendix A 7~31.doc>> <<Appendix B 8~1.doc>> <<Appendix C 8~13.doc>>

<<Appendix D.doc>> <<Appendix D~Worksheets 8~13~02.xls>>

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<<Appendix D.doc>> <<Appendix D~Worksheets 8~13~02.xls>>

From:	Phillips, John M -GEN04W [john.phillips@pse.com]
Sent:	Wednesday, August 14, 2002 11:17 AM
To:	'Horvath, Julius G - TOP-PPO2-2'; Seabrook, Joe
Cc:	Rodrigues, Melvin (E-mail); Jimma, Kebede M.; William A Mittelstadt (E-mail) (E-mail); Robinett, Wayman
Subject:	RE: G12 Reliability

Julius,

The Tono phase shifter has 9 steps between 4.7deg and 26 deg. The unit is almost always held at the 4.7 deg step which is the most restrictive step for flow from Paul to Tono. Under heavy load conditions, operating this way helps reduce flow on the transformer in the event of a major loss of the BPA Olympia source (e.g. common ROW loss of BPA Oly-PSE Oly #1 & 2, BPA Oly 115kV bus outage, BPA Oly 230kV West bus outage, etc.) The step can be adjusted by supervisory to increase flow on the transformer in the event of an emergency.

PSE's concern is more tied to the bus outages and breaker failures at the BPA Oly 230 kV bus. Looking at a normal heavy 2003 winter case, I have found that a breaker failure at either of BPA's 230kV bus sections, West or East, causes voltage collapse on the Olympic Peninsula, and uncontrolled loss of load. In addition, we are concerned that the West bus outage voltage collapse also impacts PSE's Thurston County network served out of PSE's Olympia substation. Our hope is that the project with a new bank at Shelton will also resolve this problem. Resolving voltage collapse and uncontrolled loss of load in the Peninsula and Thurston County should be sited as an additional benefit of the project.

We appreciate your ongoing efforts on this project.

John

Note E-Mail Address Change: john.phillips@pse.com

John Phillips
Consulting Engineer
Electric Transmission
Location: 10608 NE 4 St, Bellevue WA
External Phone: (425) 462-3579
Internal Phone: 81-3579

-----Original Message-----
From: Horvath, Julius G - TOP-PPO2-2 [mailto:jghorvath@bpa.gov]
Sent: Tuesday, August 13, 2002 8:00 AM
To: 'Seabrook, Joe'; Horvath Julius (E-mail)
Cc: Rodrigues, Melvin (E-mail); Mittelstadt, Bill (E-mail); Phillips, John M -GEN04W; Robinett, Wayman
Subject: RE: G12 Reliability

Joe,

Actually, I have never been able to get information from PSE on how Tono is operated so I had to go off of information that other people here at BPA had on it. The only information was able to obtain in house were the different phase angles that the phase shifter is operated at and not how PSE actually operates it. In my studies I was able to prevent any overloads for the double bank outage by adjusting the phase angle of Tono. The 500/230 kV bank would help alleviate the double 230/115 bank outage, but it seems like a high price if you can just change the phase angle on Tono. Like I said, I have been unable to get operating information on Tono from PSE, so I used the information that I did find (and I did ask for this information on more than one occasion). If my assumptions on how Tono is operated are incorrect, then I would need the correct data to do the studies correctly. On the other hand, we do mention that the breaker failure of the Olympia 230 kV bus is a critical outage in the report because it does cause a voltage collapse on the Peninsula, but this is caused by more than just the loss of the two 230/115 banks.

Julius

-----Original Message-----
From: Seabrook, Joe [mailto:joe.seabrook@pse.com]
Sent: Monday, August 12, 2002 4:35 PM
To: Horvath Julius (E-mail)
Cc: Rodrigues, Melvin (E-mail); Mittelstadt, Bill (E-mail); Phillips, John M -GEN04W; Robinett, Wayman
Subject: G12 Reliability

Julius,

John and I were talking about the reliability impacts of building or delaying G12. In the ITRC report appendix on G12, I don't think it addresses the impacts for the Olympia area.

Currently, a 230 kV bus or 115 kV bus outage that takes out both 230-115 kV transformers at Olympia results in overloads on the Tono PVART. The result would then be cascading outages affecting Thurston County, and perhaps more.

On the phone a couple of weeks ago I think that you said that putting the 500-230 transformer at Shelton resolves the double transformer outage due to new support from Shelton. I think that this reliability benefit and solution needs to be also described in G12. I think it is another important reason for installing the project as soon as you can.

Do you agree with this assessment, or could you restate it in your words?

Joe

Wright, April E - LC-7

From: Morris, Ken [Ken.Morris@pacificorp.com]
Sent: Tuesday, August 13, 2002 3:20 PM
To: Mittelstadt, Bill (RPTF)
Subject: RE: ITRC Meeting Announcement

Bill - will there be a telephone call-in option for the meeting?

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Tuesday, August 13, 2002 9:14 AM
To: Brattebo, Scott; Carr, Geoff; CARTER, LAWRENCE; Eden, Jim; Elizeh, Edison; 'Goddard, Richard'; Groce, Ed; HORVATH, JULIUS; Johnson, Don; Juj, Hardev; KEENAN, GERALD; Kinney, Scott; KOSTEREV, DMITRY; LANDAUER, MARVIN; Leland, John; Lu, Franklin; Martinsen, John; Morris, Ken; Phillips, John; QUINATA, JOHN; Reedy, Dana; RODRIGUES, MELVIN; Rust, Jerry; RYDELL, KENDALL; Schellberg, Ron; Seabrook, Joe; SILVERSTEIN, BRIAN; STADLER, LAWRENCE; VANZANDT, VICKIE; Waples, Scott
Cc: Mittelstadt, Bill - TOM-PPO2-2
Subject: ITRC Meeting Announcement

The Columbia Room at the Portland Airport PDX Conference Center has been reserved for Tuesday August 20th to review new revisions to the ITRC report discussed by conference call yesterday and to review a committee drafted cover letter as requested by the group. The meeting will commence at 9 am and is exected to be completed by 2 pm. I am working on incorporating comments in the report and expect to have it out for distribution by Wednesday morning.

Bill Mittelstadt

<<William A Mittelstadt (E-mail).vcf>>

===

Wright, April E - LC-7

From: Groce, Ed [ed.groce@avistacorp.com]
Sent: Tuesday, August 13, 2002 9:33 AM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Subject: RE: Marketer Funding of Transmission

Bill,

Thanks for the followup.

Ed

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Tuesday, August 13, 2002 9:29 AM
To: 'Groce, Ed'
Cc: Mittelstadt, Bill - TOM-PPO2-2; Lahmann, Bob - TM-Ditt2
Subject: Marketer Funding of Transmission

Ed

I talked yesterday with Bob Lahmann, (360) 418-2092, about your question of managing risk in connection with marketer funding of transmission projects. Bob mentioned that as we enter construction a credit agreement is established involving BPA, the marketer funding the project and a bank upon which BPA can draw for construction of the facilities. In this arrangement the bank has the responsibility to pay the cost of construction in the event that the marketer defaults. There is a cost of this provision that depends on project and participant credit rating . If you have further question on this please feel free to contact Bob at the above number. This is more detail than we want to put in the report but it is important for you to know.
Bill

<<William A Mittelstadt (E-mail).vcf>>

From: Hardev Juj [Hardev.Juj@ci.seattle.wa.us]
Sent: Tuesday, August 13, 2002 8:40 AM
To: ed.groce@avistacorp.com; skinney@avistacorp.com; swaples@avistacorp.com; blsilverstein@bpa.gov; dnkosterev@bpa.gov; glkeenan@bpa.gov; jfquinata@bpa.gov; jghorvath@bpa.gov; karydell@bpa.gov; ldcarter@bpa.gov; lwstadler@bpa.gov; mjlandauer@bpa.gov; mtrodrigues@bpa.gov; vrvanzandt@bpa.gov; wmittelstadt@bpa.gov; Franklin Lu; RSchellberg@idahopower.com; jleland@mtpower.com; dana.reedy@nwpp.org; jerry.rust@nwpp.org; Don.Johnson@pacificorp.com; edison.elizeh@pacificorp.com; Ken.Morris@pacificorp.com; scott.brattebo@pacificorp.com; ghcarr@pacifier.com; jim_eden@pgn.com; richard_goddard@pgn.com; jphill@puget.com; jseabr@puget.com; JDMartinsen@snopud.com
Subject: Re: ITRC Meeting Announcement

Bill, I am sorry as I have schedule conflict. I have talked to John Martinsen and he will have my proxy in case there is need for it.

My concern is that we have to define the process so we don't have to go through this each time. TPC can be assigned to review the projects (may be through NRTA, now that BPA is back again) and send the recommendations back to the project sponsor, transmission owner or IPP or marketer. With all the comments incorporated the sponsor will send the final report to ITRC for their review and ITRC will prepare and sign the cover letter. Thanks

>>> "Mittelstadt, Bill - TOM-PPO2-2" <wmittelstadt@bpa.gov> 08/13/02 08:14AM >>>
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Sent: Tuesday, August 13, 2002 8:20 AM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Cc: Robinett, Wayman; Reese, Chris
Subject: RE: ITRC Meeting Announcement

Bill,
Please add Wayman and Chris to your distribution list.
Thanks,
John

Note E-Mail Address Change: john.phillips@pse.com

John Phillips
Consulting Engineer
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Location: 10608 NE 4 St, Bellevue WA
External Phone: (425) 462-3579
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Sent: Tuesday, August 13, 2002 8:14 AM
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Wright, April E - LC-7

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Sent: Monday, August 12, 2002 4:35 PM
To: Horvath Julius (E-mail)
Cc: Rodrigues, Melvin (E-mail); Mittelstadt, Bill (E-mail); Phillips, John M -GEN04W; Robinett, Wayman
Subject: G12 Reliability

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On the phone a couple of weeks ago I think that you said that putting the 500-230 transformer at Shelton resolves the double transformer outage due to new support from Shelton. I think that this reliability benefit and solution needs to be also described in G12. I think it is another important reason for installing the project as soon as you can.

Do you agree with this assessment, or could you restate it in your words?

Joe

Wright, April E - LC-7

From: Waples, Scott [scott.waples@avistacorp.com]
Sent: Monday, August 12, 2002 1:44 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'; Rodrigues, Melvin - TOP-PPO2-2
Subject: ITRC Report

Gentlemen-
Here is the language (and please feel free to hack at it) that I would propose we put in place of the existing G9 language in the "Projects Reviewed in 2001" section (and then not include any West of Hatwai appendix):

G9 Bell - Coulee 500 kV Line
This project, which is intended to increase capacity across the West of Hatwai bottleneck, is on schedule for Fall 2004 energization as reported in last year's report. Since that time, agreement has been reached on additional Phase 1 facilities (many of which were included on the list of potential Phase 2 projects in the 2001 Infrastructure Technical Review Committee Report), which are presently planned for energization between 2003 and 2007. These facilities, which will be constructed by the Avista Corporation, include the following projects:

Benewah-Shawnee 230 kV Line.
Dry Creek 230 kV Switching Station.
Beacon-Rathdrum Double Circuit 230 kV Line.
Increase operating limits on Hatwai-Lolo 230 kV Line.
Increase operating limits on Hatwai-North Lewiston 230 kV Line.
Increase operating limits on Dry Creek-North Lewiston 230 kV Line.
Install 230 kV shunt capacitors at Benewah (200 MVAR).
Install 230 kV shunt capacitors at Dry Creek (200 MVAR).

All of the facilities listed above (including the Bell-Coulee 500 kV line) will be taken through the WECC Regional Planning Process as a "joint project" (although since the Bell-Coulee 500 kV line has already been through the process, it is expected that this will be an abbreviated process with comments only the additional facilities). Any additions or changes to the above list of projects will be identified through the Regional Planning Process. The complete slate of Phase I facilities reinforcing the West of Hatwai Path will then be taken through the WECC Path Rating Process. Additional (West of Hatwai Phase II) facilities, which may be necessary in the Northern Idaho / Western Montana area will be identified in a second phase of study effort which will begin once the Phase I facilities are in Phase III of the Path Rating Process.

From:	Seabrook, Joe [joe.seabrook@pse.com]
Sent:	Friday, August 09, 2002 3:26 PM
To:	Mittelstadt, Bill (E-mail)
Cc:	Robinett, Wayman; Marshall, George; Reese, Chris; Phillips, John M -GEN04W; 'Morris, Ken (E-mail)'; 'Martinsen, John (E-mail)'; 'Juj, Hardev (E-mail)'; 'Waples Scott (E-mail)'; 'Schellberg Ron (E-mail)'; 'Leland John (E-mail)'; 'Eden, Jim (E-mail)'; 'Johnson, Don (E-mail)'; Stadler, Larry W - TOP-PPO2-2; Horvath, Julius G - TOP-PPO2-2; Rodrigues, Melvin - TOP-PPO2-2
Subject:	RE: Conference Call of Infrastructure Technical Review Committee, Aug. 9, 9:00 Pacific

Hi Bill,

The Infrastructure Technical Review Committee (ITRC) had a conference call meeting this morning, and developed some recommendations for the July 19, 2002 report. We had not met for some time, and it was very helpful to have the call.

The main recommendations were: (a) the ITRC should author the cover letter to the report, since ITRC is signing the letter; (b) the specifics of certain projects (e.g., plan of service) need further development and coordination between BPA and ITRC; and (c) increasing BPA borrowing authority for transmission by $1 billion needs further explanation.

I am attaching the report that you sent out for review and approval, with changes that we recommend shown in red-line markup. Please read these comments for the Monday conference call, if possible.

Thanks, Joe

Report Draft
7~191_.doc

Upgrading the Capacity and Reliability of the BPA Transmission System

Report ~~of~~ to the Infrastructure Technical Review Committee

July 19, 2002

Table of Contents

Appendices

Please refer to the August 30, 2001 Infrastructure Review Committee report for information on the purpose of this Committee, terms of engagement and general system need. Also please refer to this report for system maps.

1. Executive Summary

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002). Problems with the transmission in the region are manifested in several ways:

- Chronic congestion existing on a number of transmission paths requires curtailment of both firm power deliveries and economy energy.
- Resolution of the Western energy crisis requires development of new generating resources. The vast majority of proposed Northwest resources cannot obtain firm transmission service, or be integrated, without additional bulk transmission.
- While power loads have been growing steadily at 1.8% annually and the use of the transmission system is up by over 2% annually, few bulk grid transmission lines were added in the past 15 years.
- It will take much longer to site and build transmission to deliver needed new generation than it will take to build and site the generation. New transmission is needed to meet existing and future obligations in order to comply with ~~recently adopted~~ national and regional standards that ensure a reliable power system.
- It is extremely difficult to meet obligations when facilities are removed from service to conduct normal maintenance or to construct new facilities.

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

The Infrastructure Technical Review Committee (ITRC) was formed in 2001 at the behest of some of BPA's customers to support BPA's efforts to secure funding for BPA's infrastructure proposals. Once a year, the ITRC evaluates and prioritizes BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. The committee draws on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC), Operating Committee (OC) and the Northwest Regional Transmission Association (NRTA) Planning Committee (PC). The committee's review is one of several reviews for BPA's proposals. BPA participates in the committee's work by submitting proposed transmission investments and by facilitating the committee's review of those proposals. BPA does not vote on the committee's findings and does not fund the work of the ITRC.

The committee was asked to report its initial recommendations by August 30, 2001 to enable BPA to install necessary system facilities as soon as possible.

This review is the second in an annual process to coincide with BPA's annual budget cycle. It covers four projects of BPA's infrastructure proposal. Review of additional projects will be conducted in subsequent years. There are several additional parallel efforts that provide for review of proposed transmission additions. This committee's analysis and recommendations will be shared and further analyzed in the following forums.

- Northwest Power Pool (NWPP) Transmission Planning Committee
- Western Electricity Coordinating Council (WECC) Regional Planning Group
- National Environmental Policy Act (NEPA) review for individual projects

During the first part of 2002 the committee met twice to review additional infrastructure proposal developed by BPA. While some of the proposals have been under development in previous forums with outside participation, other proposals were presented for the first time. The committee has reached the following conclusions and recommendations based on its review:

Projects Reviewed in 2001:

- Projects evaluated in previous years should continue on the revised timetable proposed by BPA. BPA should continue to reevaluate project need and timelines, particularly for projects driven by generation integration.
- In accordance with provisions in the January 15, 2002 guidelines[1] BPA provided a status report on projects that were approved last year. There were no significant changes in circumstances that necessitated any of these projects be returned to the committee for a full review.
- INSERT SHORT UPDATES FROM BPA FOR EACH OF THE G-9 PROJECTS.

Projects Reviewed in 2002:

- ~~There continues to be a compelling and immediate need to upgrade portions of the Northwest bulk transmission grid. Solutions proposed by BPA in coordination with others address the identified problems.~~
- ~~Projects evaluated in the first review should continue on the revised timetable proposed by BPA. BPA should continue to reevaluate project need and timelines, particularly for projects driven by generation integration.~~
- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G12 (Olympic Peninsula Reinforcement) is high priority and should be implemented as soon as possible.~~is also important, although the need date is later than initially estimated based on the most recent load forecasts~~. Opportunities for non-transmission alternatives ~~should~~have been pursued in parallel with the proposed transmission fix. (– BASED ON BPA'S PROJECT DISCRIPTIONS, G-12 HAS A HIGHER PROBABILITY OF OCCURING THAN G10, MORE IMMEDIATE LOAD AT RISK AND MORE HOURS AT RISK)

- Projects G13 (Paul – Troutdale 500-kV Line) and G14 (Hanford-Ostrander 500 kV loop-in) were examined on a preliminary basis. Project G13 is critical to integration of new generation in the I-5 corridor. BPA should complete details of the plan of service ~~over the next 60 days~~ by November 1, 2002 and bring this through the WECC Regional Planning Process. In addition, coordination with PGE is required. The benefits of project G14 are not clear given proposed I5 generation development and potential higher costs to route around the Columbia Gorge Scenic Area. BPA should bring these projects forward to the committee for consideration in 2003 after further examination of alternatives and need.

Rate and Budgetary impacts

- There continues to be a compelling and immediate need to upgrade portions of the Northwest bulk transmission grid. Solutions proposed by BPA in coordination with others address the identified problems.
- ~~The need still remains to increase BPA borrowing authority for *transmission* by at least $1 billion in order to ensure that sufficient financial resources are available to accomplish transmission expansion over a ten-year planning horizon (see Figure 1, TBL Capital Projects Historical & Future, on page 7).~~ (WE NEED TO DISCUSS THIS. MORE SUPPORTING DOCUMENTATION IS NEEDED)
- BPA should continue to pursue and evaluate third party financing opportunities for major new transmission projects.
- Preliminary analysis has shown that increased transmission use will recover the cost of the proposed capital additions (see appendix D for economic analysis). (–ADD PREVIOUSLY SENT OUT ECONOMIC ANALYSIS FOR EACH PROJECT TO APPENDIX D)~~.~~ Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure 10 to 20 year firm transmission service contracts with appropriate credit provisions before proceeding with construction. (Note: BPA's transmission investments are repaid by its transmission customers, not taxpayers.)
- Additional reinforcements by BPA and others are needed to maximize reliability and transfer capability from the proposals. Other Northwest utilities have planned transmission additions, and maximum benefits will be achieved through coordinated development~~.~~
- Future reviews should be conducted annually to evaluate and prioritize BPA proposed major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers. ~~In accordance with provisions in the January 15, 2002 guidelines[1] BPA provided a status report on projects that were approved last year. There were no significant changes in circumstances that necessitated any of these projects be returned to the committee for a full review.~~

2. Projects for 2002 Review

Project List

Project		Cost (loaded) ($M)	Energization Date	Capacity Added MW
Portland Area Additions	G10	9	2003	300
Olympic Peninsula Reinforcement	G12	26	2005	430
Total		35		

Project Drivers

	Load Service	Entitlement Return	Generation Integration	Transfers	Reliability	O&M Savings	BiOp
G10	x				x		
G12	x				x		

3. Glossary of Acronyms and Terms

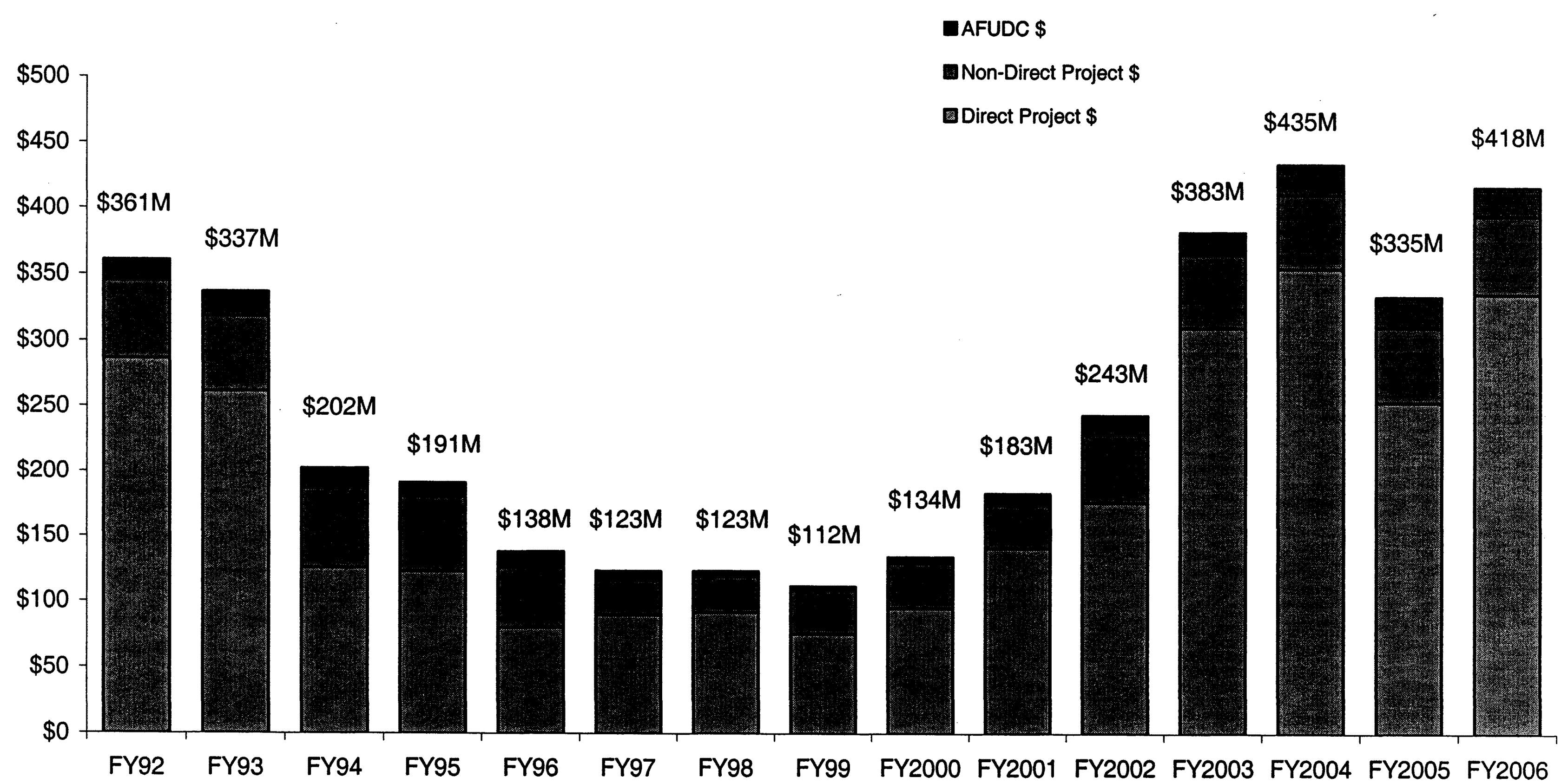
BiOp	Biological Opinion
MW	A unit of power. One MW would serve approximately 700 homes.
NRTA	Northwest Regional Transmission Association
NWPP	Northwest Power Pool
RTO	Regional Transmission Organization
WECC	Western Electricity Coordinating Council

Bulk Transmission – Transmission lines that serve as the backbone of the grid, typically operated at voltages of 230-kV and above.

4. References

[1] "Annual BPA Transmission Infrastructure Review," January 15, 2002.

Figure 1. TBL Capital Projects Historical & Future Trend



From: Robinett, Wayman [wayman.robinett@pse.com]
Sent: Tuesday, August 06, 2002 9:36 AM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Subject: RE: ITRC Report for Approval

Dick, I've just returned from vacation and will be discussing this matter with my staff soon.

Note Email Address Change: wayman.robinett@pse.com
Wayman Robinett
Puget Sound Energy
Office 1-360-571-7680
Pager 1-888-444-6792
Fax 1-360-573-7743
Cell 1-206-604-5270

From: Mittelstadt, Bill - TOM-PPO2-2 [SMTP:wmittelstadt@bpa.gov]
Sent: Tuesday, July 30, 2002 1:48 PM
To: 'Morris, Ken'; 'Martinsen, John'; 'Robinett, Wayman'; 'Juj, Hardev'; 'Waples, Scott'; 'Schellberg, Ron'; 'Leland, John'; 'Eden, Jim'
Cc: Silverstein, Brian L - TOP-PPO2-2
Subject: FW: ITRC Report for Approval

Hi

This is a friendly reminder that tomorrow July 31 is the request date for
returning a signed copy of the cover letter to me by mail and fax.

Thanks,

Bill

<<William A Mittelstadt (E-mail).vcf>>
> -----Original Message-----
> From: Mittelstadt, Bill - TOM-PPO2-2
> Sent: Friday, July 19, 2002 4:35 PM
> To: Brattebo, Scott; Carr, Geoff; CARTER, LAWRENCE; Eden, Jim; Elizeh,
> Edison; 'Goddard, Richard'; Groce, Ed; HORVATH, JULIUS; Johnson, Don; Juj,
> Hardev; KEENAN, GERALD; Kinney, Scott; KOSTEREV, DMITRY; LANDAUER, MARVIN;
> Leland, John; Lu, Franklin; Martinsen, John; Morris, Ken; Phillips, John;
> QUINATA, JOHN; Reedy, Dana; RODRIGUES, MELVIN; Rust, Jerry; RYDELL,
> KENDALL; Schellberg, Ron; Seabrook, Joe; SILVERSTEIN, BRIAN; STADLER,
> LAWRENCE; VANZANDT, VICKIE; Waples, Scott
> Cc: Haner, John - TOM-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2; Maher,
> Mark W - T-DITT2; Whitney, Carolyn A - T-DITT2; Combs, Chuck - LT-7
> Subject: ITRC Report for Approval
>
> Infrastrucure Technical Review Committee
>
> Attached is the revised report and attachments incorporating

> additions/revisions per comments received by committee members.
> Significant changes include the following:
>
> * Estimation of societal cost of outages for the "do nothing"
> alternative
> * Corrections to estimating event probability and mean time
between
> failure
> * Addition of tables addressing various risks for G10 and G12
> * Explicit summarizing of factors applying to the decision for
project
> G10
> * Emphaisis that non-transmission alternatives will be pursued
in
> parallel for project G12
> * Inclusion of the phrase "...with appropriate credit
provisions"
> (report page 5) in reference to projects funded by generation
providers to
> avoid risk of stranded investment
> * Emphais that project G13 will be expedited through the
Regional
> Planning Process this year and then resubmitted to the ITRC.
>
> Please review the report and return by mail and fax a signed copy
of the
> cover letter to me by Wednesday July 31, 2002. My mailing address
and fax
> number is given below. I plan to be out of the office July 22-29.
If you
> have questions during that time please contact Brian Silverstein
at (360)
> 619-6651.
>
> Thanks very much for your participation and support in completing
this
> report!
>
> Bill Mittelstadt
>
> William Mittelstadt TOM
> Bonneville Power Administration
> Parkway Plaza (Mail Center)
> 8100 NE Parkway
> Vancouver, WA 98662
> (360) 619-6672
> (360) 619-6945 fax
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>
> <<William A Mittelstadt (E-mail).vcf>> <<File: William A
Mittelstadt (E-mail).vcf>><<File: William A Mittelstadt (E-mail).vcf>>

From: Waples, Scott [scott.waples@avistacorp.com]
Sent: Monday, August 05, 2002 1:08 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Subject: RE: ITRC Report

Bill-
Roger will be back tomorrow and I just need to run this by him.
Scott

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Monday, August 05, 2002 10:34 AM
To: 'Morris, Ken'; 'Martinsen, John'; 'Robinett, Wayman'; 'Juj, Hardev'; 'Waples, Scott'; 'Schellberg, Ron'; 'Leland, John'; 'Eden, Jim'
Cc: 'Goddard, Richard'; VanZandt, Vickie - TO; Mittelstadt, Bill - TOM-PPO2-2; Rodrigues, Melvin - TOP-PPO2-2; 'Groce, Ed'
Subject: ITRC Report
Importance: High

ITRC

Thanks to those who have responded by sending a signed copy of the signature page and those who have been in contact with me and plan to complete that this week. I have received a number of comments on improving the text and flow of Appendix C from Jim Eden which are helpful. Attached is an updated copy of the report and a file summarizing the changes that have been received and incorporated. These changes do not alter the substance of the report and should not cause any problem for those who have already replied. The cover letter is unchanged.

For those who have not replyed yet please take the time reply by fax (360) 619-6945 with a signed copy of the cover letter and a hard copy in the mail. My goal is to distribute the report next week to your management representatives and the BPA administrator as was done last year indicating completion of this assignment to us.

I realize that this is a very busy time and also some may be out for vacation. Thanks for your help on this effort.

Bill Mittelstadt

Signed copies received from:
John Leland
John Martinsen
Ron Schellberg

Phone/email replies received from:
Jim Eden (editorial changes included)
Ken Morris

<<Cover Letter 7~19.doc>> <<Report Draft 8~1.doc>> <<Appendix A 7~31.doc>> <<Appendix B 8~1.doc>> <<Appendix C 8~1.doc>> <<Appendix D.doc>> <<Clarifications and Editorial Changes.doc>>

<<William A Mittelstadt (E-mail).vcf>>

Wright, April E - LC-7

From: Leland, R J (John) [John.Leland@northwestern.com]
Sent: Monday, August 05, 2002 11:43 AM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Subject: RE: ITRC Report

Bill -
In Attachement A should you change MPC to NWE and put in my new email?

John Leland
NorthWestern Energy
40 E. Broadway St.
Butte, MT 59701
(406) 497-3383
john.leland@northwestern.com

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Monday, August 05, 2002 11:34 AM
To: 'Morris, Ken'; 'Martinsen, John'; 'Robinett, Wayman'; 'Juj, Hardev'; 'Waples, Scott'; 'Schellberg, Ron'; 'Leland, John'; 'Eden, Jim'
Cc: 'Goddard, Richard'; VanZandt, Vickie - TO; Mittelstadt, Bill - TOM-PPO2-2; Rodrigues, Melvin - TOP-PPO2-2; 'Groce, Ed'
Subject: ITRC Report
Importance: High

<< File: Cover Letter 7~19.doc >> << File: Report Draft 8~1.doc >> << File: Appendix A 7~31.doc >> << File: Appendix B 8~1.doc >> << File: Appendix C 8~1.doc >> << File: Appendix D.doc >> << File: Clarifications and Editorial Changes.doc >> << File: William A Mittelstadt (E-mail).vcf >>
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<<William A Mittelstadt (E-mail).vcf>>

Wright, April E - LC-7

From: Martinsen, John [JDMartinsen@SNOPUD.com]
Sent: Thursday, August 01, 2002 9:42 AM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Subject: RE: ITRC Report for Approval

Bill the signed letter is in the mail -I have been out quite a bit the last few weeks so I apologize for the delay. I was not as active on the second phase "G" projects except for the Bell Coulee project effort. But I have gone through the material and we support the BPA transmission expansion efforts.

If you have any questions or comments please give me a call.

Thanks
Thanks,

John D. Martinsen
System Planning and Protection

PHONE NUMBER: 425-347-4327
CELLULAR NUMBER: 425-345-0537
FAX NUMBER: 425-267-6122
E-MAIL: jdmartinsen@snopud.com

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Tuesday, July 30, 2002 1:48 PM
To: 'Morris, Ken'; 'Martinsen, John'; 'Robinett, Wayman'; 'Juj, Hardev'; 'Waples, Scott'; 'Schellberg, Ron'; 'Leland, John'; 'Eden, Jim'
Cc: Silverstein, Brian L - TOP-PPO2-2
Subject: FW: ITRC Report for Approval

<< File: William A Mittelstadt (E-mail).vcf >> << File: William A Mittelstadt (E-mail).vcf >> Hi

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Thanks,

Bill

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> From: Mittelstadt, Bill - TOM-PPO2-2
> Sent: Friday, July 19, 2002 4:35 PM
> To: Brattebo, Scott; Carr, Geoff; CARTER, LAWRENCE; Eden, Jim; Elizeh,
> Edison; 'Goddard, Richard'; Groce, Ed; HORVATH, JULIUS; Johnson, Don; Juj,
> Hardev; KEENAN, GERALD; Kinney, Scott; KOSTEREV, DMITRY; LANDAUER, MARVIN;
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> KENDALL; Schellberg, Ron; Seabrook, Joe; SILVERSTEIN, BRIAN; STADLER,
> LAWRENCE; VANZANDT, VICKIE; Waples, Scott
> Cc: Haner, John - TOM-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2; Maher,
> Mark W - T-DITT2; Whitney, Carolyn A - T-DITT2; Combs, Chuck - LT-7
> Subject: ITRC Report for Approval
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> Infrastrucure Technical Review Committee
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> Attached is the revised report and attachments incorporating
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> * Estimation of societal cost of outages for the "do nothing"
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> Please review the report and return by mail and fax a signed copy of the
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> 619-6651.
>
> Thanks very much for your participation and support in completing this
> report!
>
> Bill Mittelstadt
>
> William Mittelstadt TOM
> Bonneville Power Administration
> Parkway Plaza (Mail Center)
> 8100 NE Parkway
> Vancouver, WA 98662
> (360) 619-6672
> (360) 619-6945 fax
>
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>
> <<William A Mittelstadt (E-mail).vcf>>

Wright, April E - LC-7

From: Groce, Ed [ed.groce@avistacorp.com]
Sent: Monday, July 22, 2002 2:59 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'; Groce, Ed
Cc: Waples, Scott; Silverstein, Brian L - TOP-PPO2-2; Meyers, Lloyd
Subject: RE: ITRG Draft Report

Bill,

Thanks for the addition. The term "appropriate credit provisions" is rather broad in definition, however, is good in the context of this report. Also, I don't know how much ability BPA has to set separate credit provisions for generation project developers. We just don't want to be paying for defunct generation project transmission.

Ed

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Wednesday, July 17, 2002 12:24 PM
To: 'Groce, Ed'
Cc: 'Waples, Scott'; Silverstein, Brian L - TOP-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2
Subject: RE: ITRG Draft Report

Ed

Thanks for your comments. I suggest that we add the phrase "...with appropriate credit provisions" as shown below. Let me know if this is ok or if you have another suggestion.

Thanks

Bill

"Preliminary analysis has shown that increased transmission use will recover the cost of the proposed capital additions. Where the generation project developers are not funding upgrades in advance of construction, BPA should secure 10 to 20 year firm transmission service contracts before proceeding with construction, with appropriate credit provisions. (Note: BPA's transmission investments are repaid by its transmission customers, not taxpayers.)"

-----Original Message-----
From: Groce, Ed [mailto:ed.groce@avistacorp.com]
Sent: Thursday, July 11, 2002 5:05 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'; 'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; Groce, Ed; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; Kinney, Scott; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO; Waples, Scott
Cc: Haner, John - TOM-PPO2-2; Meyers, Lloyd; Schlect, Jeff; Maher, Patrick; Kinney, Scott

Subject: RE: ITRG Draft Report

Bill,

I have reviewed the ITRG report. I would like to comment on the last paragraph on page 4, it reads:

"Preliminary analysis has shown that increased transmission use will recover the cost of the proposed capital additions. Where the generation project developers are not funding upgrades in advance of construction, BPA should secure 10 to 20 year firm transmission service contracts before proceeding with construction. (Note: BPA's transmission investments are repaid by its transmission customers, not taxpayers.)"

Avista feels that BPA should strengthen the financial credit protection relating to requested new construction for generation project developers. The potential exists for BPA to build a multimillion dollar generation project interconnection and subsequent to that, have the developer declare bankruptcy. Without proper credit or bonding, BPA cannot recover the construction costs. As mentioned, the taxpayers will not pay this bill but the rest of BPA's transmission customers will pay without any benefit. And actually, the taxpayers of the NW will ultimately pay indirectly through higher power rates.

Scott Waples is a signatory to this report, therefore, I would be happy to work with/through him on developing credit language for this report.

Edward F. Groce
Manager Transmission Acquisition
Avista Corporation
1411 E. Mission MSC-7
PO Box 3727
Spokane, WA 99220-3727

509-495-4164 Phone
509-495-4272 Fax
509-981-1914 Cell
ed.groce@avistacorp.com

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Monday, July 01, 2002 12:48 PM
To: Mittelstadt, Bill - TOM-PPO2-2; 'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; 'Groce, Ed'; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; 'Kinney, Scott'; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO; 'Waples, Scott'
Cc: Haner, John - TOM-PPO2-2
Subject: RE: ITRG Draft Report

Hello again,

Please return any comments on this draft material that was submitted to you by July 10 so that the report can be finalized.

Thanks

Bill Mittelstadt

<<William A Mittelstadt (E-mail).vcf>>
> -----Original Message-----
> From: Mittelstadt, Bill - TOM-PPO2-2
> Sent: Monday, June 24, 2002 8:56 AM
> To: Brattebo, Scott; Carr, Geoff; CARTER, LAWRENCE; Eden, Jim; Elizeh,
> Edison; 'Goddard, Richard'; Groce, Ed; HORVATH, JULIUS; Johnson, Don; Juj,
> Hardev; KEENAN, GERALD; Kinney, Scott; KOSTEREV, DMITRY; LANDAUER, MARVIN;
> Leland, John; Lu, Franklin; Martinsen, John; Morris, Ken; Phillips, John;
> QUINATA, JOHN; Reedy, Dana; RODRIGUES, MELVIN; Rust, Jerry; RYDELL,
> KENDALL; Schellberg, Ron; Seabrook, Joe; SILVERSTEIN, BRIAN; STADLER,
> LAWRENCE; VANZANDT, VICKIE; Waples, Scott
> Cc: Mittelstadt, Bill - TOM-PPO2-2; Haner, John - TOM-PPO2-2
> Subject: ITRG Draft Report
>
> Dear Technical Review Committee Participants
>
> This year we conducted the second annual review of BPA's proposed
> transmission infrastructure projects. BPA offered four projects for
> consideration. Based on your feedback, BPA recommends that two of the
> projects be advanced: G10 (Portland Area Additions) for construction and
> G12 (Olympic Peninsula Reinforcement) for environmental review. The
> other two projects will be brought forward again.
>
> Attached please find a draft report based on the format from last year.
> It summarizes BPA's proposals and our sense of the Committee views. We
> have tried to provide the additional information you requested and
> incorporate your feedback. Please feel free to edit the documents and
> return them to me. Depending on the response we can finalize the
> documents based on your edits, set up a conference call if further
> discussion is warranted, or set up a another meeting in Portland if that's
> what you want to do.
>
> Our intention is to repeat the process with additional proposals next
> year.
>
> I appreciate the time you have taken to provide critical feedback and I
> look forward to hearing from you.
>
>
> Regards
> Bill
>
>
>
> << File: William A Mittelstadt (E-mail).vcf >> << File: Cover Letter.doc
> >> << File: Report Draft.doc >> << File: Appendix A.doc >> << File:
> Appendix B.doc >> << File: Appendix C.doc >> << File: Appendix D.doc >>
> << File: Appendix E.doc >>

Wright, April E - LC-7

From: Leland, R J (John) [John.Leland@northwestern.com]
Sent: Wednesday, July 17, 2002 3:40 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Subject: RE: Draft Report

Bill - another question.

For the G12 project, you note in the table on page C-5 that the option #1 Net PV is (7.8). On page C-8 you state that "The present value savings of a ten your delay in the project would be approximately $15 M assuming a 9% discount rate." Does this mean that delaying would result in a net benefit of $7.2 M (i.e., -7.8 + 15 M)?

John Leland
NorthWestern Energy
40 E. Broadway St.
Butte, MT 59701
(406) 497-3383
john.leland@northwestern.com

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Tuesday, July 16, 2002 5:40 PM
To: 'Leland, John'
Cc: Silverstein, Brian L - TOP-PPO2-2; Horvath, Julius G - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2
Subject: Draft Report

<< File: William A Mittelstadt (E-mail).vcf >> << File: Cover Letter revised.doc >> << File: Report Draft revised.doc >> << File: Appendix C revised.doc >> << File: Outage Costs.xls >> John

The following files represent the status of the revised drafts at this point. Also included is the Excel spreadsheet used to estimate societal costs. Lets discuss further after you have a chance to read through this. Please set your "Revisions" options to hide the deleted text and to not underline the new text since it is much easier to follow.

Bill

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Wright, April E - LC-7

From: Leland, R J (John) [John.Leland@northwestern.com]
Sent: Wednesday, July 17, 2002 3:35 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Subject: RE: Draft Report

Bill -
I note in the xls workbook for the G12 project, you use the probability for the type of load condition (e.g., extra heavy winter load = 1/20, normal winter = 1/2). Why didn't you adjust the G10 project for the abnormal load condition? This would reduce the $30 million dollar to < $15 million depending on the probability assigned.

John Leland
NorthWestern Energy
40 E. Broadway St.
Butte, MT 59701
(406) 497-3383
john.leland@northwestern.com

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From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Tuesday, July 16, 2002 5:40 PM
To: 'Leland, John'
Cc: Silverstein, Brian L - TOP-PPO2-2; Horvath, Julius G - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; Mittelstadt, Bill - TOM-PPO2-2
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From: Hardev Juj [Hardev.Juj@ci.seattle.wa.us]
Sent: Friday, July 12, 2002 11:49 AM
To: ed.groce@avistacorp.com; blsilverstein@bpa.gov; dnkosterev@bpa.gov; glkeenan@bpa.gov; jfquinata@bpa.gov; jghorvath@bpa.gov; karydell@bpa.gov; ldcarter@bpa.gov; lwstadler@bpa.gov; mjlandauer@bpa.gov; mtrodrigues@bpa.gov; vrvanzandt@bpa.gov; wmittelstadt@bpa.gov; Franklin Lu; RSchellberg@idahopower.com; jleland@mtpower.com; dana.reedy@nwpp.org; jerry.rust@nwpp.org; Don.Johnson@pacificorp.com; edison.elizeh@pacificorp.com; Ken.Morris@pacificorp.com; scott.brattebo@pacificorp.com; ghcarr@pacifier.com; jim_eden@pgn.com; richard_goddard@pgn.com; jphill@puget.com; jseabr@puget.com; JDMartinsen@snopud.com
Cc: jeff.schlect@avistacorp.com; Lloyd.Meyers@avistacorp.com; Patrick.Maher@avistacorp.com; Scott.Kinney@avistacorp.com; jmhaner@bpa.gov
Subject: RE: ITRG Draft Report

I remember having this discussion in G-9 projects. My question was that would you build that transmission line if IPP is not coming. If the answer is no, then IPP should pay the cost.. If it is going to be in BPA's rates, then I agree 100 % with Ed's e-mail that BPA should not be stuck with the stranded cost. Thanks

>>> "Groce, Ed" <ed.groce@avistacorp.com> 07/11/02 05:05PM >>>
Bill,

I have reviewed the ITRG report. I would like to comment on the last paragraph on page 4, it reads:

"Preliminary analysis has shown that increased transmission use will recover the cost of the proposed capital additions. Where the generation project developers are not funding upgrades in advance of construction, BPA should secure 10 to 20 year firm transmission service contracts before proceeding with construction. (Note: BPA's transmission investments are repaid by its transmission customers, not taxpayers.)"

Avista feels that BPA should strengthen the financial credit protection relating to requested new construction for generation project developers. The potential exists for BPA to build a multimillion dollar generation project interconnection and subsequent to that, have the developer declare bankruptcy. Without proper credit or bonding, BPA cannot recover the construction costs. As mentioned, the taxpayers will not pay this bill but the rest of BPA's transmission customers will pay without any benefit. And actually, the taxpayers of the NW will ultimately pay indirectly through higher power rates.

Scott Waples is a signatory to this report, therefore, I would be happy to work with/through him on developing credit language for this report.

Edward F. Groce
Manager Transmission Acquisition
Avista Corporation
1411 E. Mission MSC-7
PO Box 3727
Spokane, WA 99220-3727

509-495-4164 Phone
509-495-4272 Fax
509-981-1914 Cell
ed.groce@avistacorp.com

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From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Monday, July 01, 2002 12:48 PM

To: Mittelstadt, Bill - TOM-PPO2-2; 'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; 'Groce, Ed'; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; 'Kinney, Scott'; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO; 'Waples, Scott'
Cc: Haner, John - TOM-PPO2-2
Subject: RE: ITRG Draft Report

Hello again,

Please return any comments on this draft material that was submitted to you by July 10 so that the report can be finalized.

Thanks

Bill Mittelstadt

<<William A Mittelstadt (E-mail).vcf>>

> -----Original Message-----
> From: Mittelstadt, Bill - TOM-PPO2-2
> Sent: Monday, June 24, 2002 8:56 AM
> To: Brattebo, Scott; Carr, Geoff; CARTER, LAWRENCE; Eden, Jim; Elizeh, Edison; 'Goddard, Richard'; Groce, Ed; HORVATH, JULIUS; Johnson, Don; Juj, Hardev; KEENAN, GERALD; Kinney, Scott; KOSTEREV, DMITRY; LANDAUER, MARVIN; Leland, John; Lu, Franklin; Martinsen, John; Morris, Ken; Phillips, John; QUINATA, JOHN; Reedy, Dana; RODRIGUES, MELVIN; Rust, Jerry; RYDELL, KENDALL; Schellberg, Ron; Seabrook, Joe; SILVERSTEIN, BRIAN; STADLER, LAWRENCE; VANZANDT, VICKIE; Waples, Scott
> Cc: Mittelstadt, Bill - TOM-PPO2-2; Haner, John - TOM-PPO2-2
> Subject: ITRG Draft Report
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Wright, April E - LC-7

From: Groce, Ed [ed.groce@avistacorp.com]
Sent: Thursday, July 11, 2002 5:05 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'; 'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; Groce, Ed; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; Kinney, Scott; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO; Waples, Scott
Cc: Haner, John - TOM-PPO2-2; Meyers, Lloyd; Schlect, Jeff; Maher, Patrick; Kinney, Scott
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> << File: Appendix E.doc >>

From: Waples, Scott [scott.waples@avistacorp.com]
Sent: Monday, July 08, 2002 4:06 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Subject: RE: ITRG Draft Report

Bill-
It looks as if I (and others)am already a signatory to this newest draft of this report. Will we get a chance to actually sign off on it?
Thanks-
Scott

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Monday, July 01, 2002 12:48 PM
To: Mittelstadt, Bill - TOM-PPO2-2; 'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; 'Groce, Ed'; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; 'Kinney, Scott'; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO; 'Waples, Scott'
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Wright, April E - LC-7

From: Leland, R J (John) [John.Leland@northwestern.com]
Sent: Wednesday, July 03, 2002 2:47 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Subject: RE: ITRG Draft Report

Cover Letter jl.doc Report Draft jl.doc Appendix C jl.doc

Bill -
I have inserted my comments in redline format. Some of my comments are trying to push you into doing a more robust analysis that justifies your selection. Perhaps you have and haven't communicated it in the report. I didn't duplicate many comments on G12, 13 & 14 because comments on G10 apply.

<<Cover Letter jl.doc>> <<Report Draft jl.doc>> <<Appendix C jl.doc>>
I will continue looking at this and may have comments next week. Contact me if you have any question.

John Leland
NorthWestern Energy
(406) 497-3383
john.leland@northwestern.com

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Our intention is to repeat the process with additional proposals next year.

I appreciate the time you have taken to provide critical feedback and I look

June 21, 2002

Addressees

Subject: Infrastructure Technical Review Committee Report

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002).

As the operator of three-quarters of the bulk transmission in the Northwest, the Bonneville Power Administration (BPA) developed a transmission infrastructure proposal that builds upon BPA's previous transmission expansion plans. Undertaking a capital program of this magnitude will require an increase in BPA's borrowing authority as well as full consideration of third party financing options. A diverse group of Northwest electric power interests, in an August 8, 2001 letter to Vice President Cheney, strongly endorsed increased borrowing authority in order to ensure that sufficient financial resources are available to accomplish transmission expansion needed to ensure an adequate and affordable electricity system for the Northwest.

To ensure that BPA's proposal designs and prioritizes improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers, a technical and economic review committee was formed (Technical Review Committee). The committee drew on individuals who are also members of the Northwest Power Pool (NWPP) Transmission Planning Committee (TPC) and the Operating Committee (OC). The committee provided its first report on August 30, 2001 with the recommendation that BPA install necessary system facilities as soon as possible. A critical first step is securing additional borrowing authority for BPA.

Upgrading the Capacity and Reliability of the BPA Transmission System

Report of the Infrastructure Technical Review Committee

June 22, 2002

Table of Contents

Please refer to the August 30, 2001 Infrastructure Review Committee report for information on the purpose of this Committee, terms of engagement and general system need. Also please refer to this report for system maps.

1. Executive Summary

Portions of the Northwest transmission system are gridlocked. An adequate and affordable electric supply is not possible without sufficient transmission capacity. An unreliable system puts public health, safety and the economy at risk. Confirmation of these findings is contained in the National Grid Study (U. S. Department of Energy, May, 2002). Problems with the transmission in the region are manifested in several ways:

- Chronic congestion existing on a number of transmission paths requires curtailment of both firm power deliveries and economy energy.
- Resolution of the Western energy crisis requires development of new generating resources. The vast majority of proposed Northwest resources cannot obtain firm transmission service, or be integrated, without additional bulk transmission.
- While power loads have been growing steadily at 1.8% annually and the use of the transmission system is up by over 2% annually, few bulk grid transmission lines were added in the past 15 years.
- It will take much longer to site and build transmission to deliver needed new generation than it will take to build and site the generation. New transmission is needed to meet existing and future obligations in order to comply with recently adopted national and regional standards that ensure a reliable power system.
- It is extremely difficult to meet obligations when facilities are removed from service to conduct normal maintenance or to construct new facilities.

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This review is the second in an annual process to coincide with BPA's annual budget cycle. It covers two projects of BPA's infrastructure proposal. Review of additional projects will be conducted in subsequent years. There are several additional parallel efforts that provide for review of proposed transmission additions. This committee's analysis and recommendations will be shared and further analyzed in the following forums.

- Northwest Power Pool (NWPP) Transmission Planning Committee
- Western Electricity Coordinating Council (WECC) Regional Planning Group
- National Environmental Policy Act (NEPA) review for individual projects

During the first part of 2002 the committee met twice to review additional infrastructure proposal developed by BPA. While some of the proposals have been under development in previous forums with outside participation, other proposals were presented for the first time. The committee has reached the following conclusions and recommendations based on its review:

- There continues to be a compelling and immediate need to upgrade portions of the Northwest bulk transmission grid. Solutions proposed by BPA in coordination with others address the identified problems.
- Projects evaluated in the first review should continue on the revised timetable proposed by BPA. BPA should continue to reevaluate project need and timelines, particularly for projects driven by generation integration.
- Project G10 (Portland Area Additions) is high priority and should be implemented as soon as possible.
- Project G12 (Olympic Peninsula Reinforcement) is also important, although the need date is later than initially estimated based on the most recent load forecasts. Opportunities for non-transmission alternatives should be pursued in parallel with the proposed transmission fix.
- Projects G13 (Paul – Troutdale 500-kV Line) and G14 (Hanford-Ostrander 500 kV loop-in) were examined on a preliminary basis. Project G13 is critical to integration of new generation in the I-5 corridor. BPA should complete details of the plan of service over the next 60 days and bring this through the WECC Regional Planning Process. In addition, coordination with PGE is required. The benefits of project G14 are not clear given proposed I5 generation development and potential higher costs to route around the Columbia Gorge Scenic Area. BPA should bring these projects forward to the Committee for consideration in 2003 after further examination of alternatives and need.
- The need still remains to increase BPA borrowing authority for *transmission* by at least $1 billion in order to ensure that sufficient financial resources are available to accomplish transmission expansion over a ten-year planning horizon. <u>I DON'T HAVE ANY WAY TO KNOW HOW MUCH ADDITIONAL BORROWING AUTHORITY IS NEEDED. I WOULD LIKE TO SEE, PERHAPS AS AN ATTACHMENT, A "10-YEAR BUDGET" THAT SUPPORTS THIS RECOMMENDATION.</u>
- BPA should continue to pursue and evaluate third party financing opportunities for major new transmission projects.
- Preliminary analysis has shown that increased transmission use will recover the cost of the proposed capital additions. Where the generation project developers are not funding Network upgrades in advance of construction, BPA should secure 10 to 20

year firm transmission service contracts before proceeding with construction. (Note: BPA's transmission investments are repaid by its transmission customers, not taxpayers.)

- Additional reinforcements by BPA and others are needed to maximize reliability and transfer capability from the proposals. Other Northwest utilities have planned transmission additions, and maximum benefits will be achieved through coordinated development.
- Future reviews should be conducted annually to ensure that BPA designs and prioritizes major transmission projects in a manner that will provide the most cost-effective, reliable service for the region's consumers.

THE SECOND PARAGRAPH UNDER "FINALITY" IN THE JANUARY 15, 2002 AGREEMENT COMMENTS ON THE NEED FOR A REVIEW OF THE PREVIOUSLY REVIEWED PROJECTS. I WOULD SUGGEST THAT YOU INCLUDE A NEW SECTION THAT STATES NO EXTENSIVE REVIEW OF PAST PROJECTS WAS CONDUCTED THIS YEAR BECAUSE THE CONDITIONS OF THE TWO IMPORTANT EXCEPTIONS WERE NOT MET.

3. Projects for 2002 Review

Project List

Project		Cost (loaded) ($M)	Energization Date	Capacity Added MW
Portland Area Additions	G10	9	2003	300
Olympic Peninsula Reinforcement	G12	26	2005	430
Total		35		

Project Drivers

	Load Service	Entitlement Return	Generation Integration	Transfers	Reliability	O&M Savings	BiOp
G10	x				x		
G12	x				x		x

SHOULD YOU DEFINE BIOP?

3. SHOULD THIS BE #4? Glossary of Acronyms and Terms

MW A unit of power. One MW would serve approximately 700 homes.

NRTA	Northwest Regional Transmission Association
NWPP	Northwest Power Pool
RTO	Regional Transmission Organization
WECC	Western Electricity Coordinating Council

Bulk Transmission – Transmission lines that serve as the backbone of the grid, typically operated at voltages of 230-kV and above.

Appendix C – Project Summaries

G10. Portland Area Additions (Pearl 500/230 kV Transformer)

Background

The Portland area is currently served by four 500/230 kV transformers, Troutdale on the east side, McLoughlin in SE Portland, Pearl in SW Portland and Keeler on the west side. This project is another phase of reinforcing the load serving capability from the bulk transmission system into the greater Portland area. Earlier reinforcements included adding a new 230 kV double circuit line between Pearl and PGE's Sherwood substation.

Addition of the 2nd transformer at Pearl will require extension of both the 500 kV and the 230 kV buses. These extensions are within the existing Pearl substation.

Limiting Outages Addressed
Existing Pearl 500/230 kV Transformer

Benefit – Load Area Service
This project will increase the load carrying capability into the greater Portland area. Without this project it would be necessary to trip off load in the Portland area to relieve overloads during abnormal cold winter peaks for an outage of the existing Pearl transformer.

Business Case

This project provides the capacity to carry additional load in the Portland area at the rate of 75 MW per year from 2004 though 2007. Beyond that date it will provide load serving benefit to the capacity of the bank following a suitable plan to address the Big Eddy – Ostrander 500 kV line outage. For the purpose of this analysis the benefit stream is limited to 300 MW for the period beyond 2007. In the Table below, Alternative 1 is the preferred plan. Alternatives 2 and 3 are described on the next page.

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV Rev-Cst	~~B~~Rev/ C	Repayment Years	In Service	Life
1	30.8	11.2	19.6	2.75	6	2003	2037
2	30.8	32.6	(1.8)	0.95	14	2003	2037
3	30.8	54.4	(23.7)	0.57	25	2003	2037
1 (0.9%)	26.9	11.9	15.0	2.26	8	2003	2037

REPLACE THE 1, 2, 3 ALTERNATIVE ABOVE WITH THE NAME OF THE ALTERNATIVE (OR ON THE NEXT PAGE IDENTIFY WHAT IS ALTERNATIVE 1, 2, AND 3).

THERE ARE 4 ALTERNATIVES LISTED BELOW (I'VE SUGGESTED ADDING A FIFTH). YOU NEED TO COMPLETE AN ECONOMIC ANALYSIS ON ALL OF THEM AND SHOW THE RESULTS IN THE ABOVE TABLE.

Risk

The risk of cost recovery of this project is related to the Portland area load growth rate. Halving the 1.8% assumed growth rate extends the cost recovery period to from 6 years to 8 years. This constitutes a very low risk.

THERE MUST BE OTHER RISKS AND/OR UNCERTAINTIES. FOR EXAMPLE, IS THERE A RISK/UNCERTAINITY ABOUT THE ABILITY TO EXPAND SUBSTATION AT PEARL? ARE THE COST AND REVENUE ESTIMATES UNCERTAINTIES – WHAT WOULD HAPPEN IF YOU CHANGED THEM BY ± 20% OR 10%? WHAT IS THE RISK OF DOING NOTHING? IS THEIR ANY RISK/UNCERTAINTY REGARDING ENVIRONMENTAL IMPACT (IN THE DECISION YOU SAY MINIMAL ENVIRONMENTAL IMPACT SO YOU SHOULD DISCUSS IT HERE)? IS THERE A RISK/UNCERTAINITY REGARDING DELIVERY TIME AND HOW WOULD THAT IMPACT CUSTOMERS? ETC.

Project Description
This project adds a 2nd 500/230 kV transformer at the existing Pearl Substation. The new transformer will be 3 ~~single phase~~single-phase units (433 MVA each). The new bank will be equipped with a 9 step LTC and a tertiary for station service. One 500 kV breaker and one 230 kV breaker will be added. The 500 kV and 230 kV buses will be extended.

Alternatives Considered

- Install a 500/230 kV transformer at PGE's Sherwood Substation. This location would be higher cost, require additional property and would be difficult to site. It was considered in the past, but the decision was made to increase the 230 kV capacity between Pearl and Sherwood.
- Install a 500/230 kV transformer at McLaughlin Substation.
- Curtail load in the event of a transformer outage (no build).
- Demand side management.
- DO NOTHING

No-Build Alternative - DO NOTHING
The "no build" alternative represents the risk of firm load interruption for a first contingency 500/230 transformer outage at any of the four following locations: Keeler; Pearl; McLaughlin; Troutdale. Load interrupted ranges from 75 MW in 2004 to 900 MW in 2015. Based on a ~~single phase~~single-phase transformer outage failure rate of once/100 years the expected composite failure rate is:

MTBF = (100 years/transformer)/(4 banks*3 transformers/bank)
MTBF = 8 years

I DON'T UNDERSTAND THIS CALCULATION. DOES THE FOLLOWING APPLY?

Pr(outage for 1 bank) = 1/100 = 0.01
Pr(no outage) = 1.0 – 0.01 = 0.99
Pr(no load interruption for 1 transformer – 3 single banks) = 0.99^3 = 0.9703
Pr(no load interruption 4 transformers) = 0.9703^4 = 0.8864
Pr(load interruption 4 transformers) = 1 – 0.8864 = .1136
=> MTBF = 1/.1136 = 9 yr approx

Non-Transmission Alternatives

As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and Environmental Economics, Nov. 2001 (available at <http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm>). BPA concluded that these measure could not be implemented in time and in sufficient magnitude to adequately address the problem. BPA will fully consider these measures for future needs.

Decision

BPA chose the preferred plan because it has the lowest initial cost and minimal environmental impacts. It is a robust choice under lower load growth and presents minimal business risk. WHY IS THE DO NOTHING ALTERNATIVE UNACCEPTABLE?

THIS SECTION IS YOUR DECISION RULE. I WOULD HOPE TO SEE IN THIS SECTION A DISCUSSION OF THE TRADEOFFS BETWEEN THE ALTERNATIVES ANY WHY THE SELECTED ALTERNATIVE IS THE BEST. COST MAY BE ONLY ONE CONSIDERATION IN THE DECISION PROCESS (E.G., COST, RISK/UNCERTAINTY, RELIABILITY, REVENUE, CUSTOMER IMPACT, ETC).

Energization Date:	**Fall 2003 (Preferred Alternative)**
Estimated Cost:	**$9M**

G12. Olympic Peninsula Reinforcement (Paul-Shelton 500-kV line)

Background

The Olympic Peninsula area load is served from Olympia substation via 230-kV and 115-kV transmission. The major source to Olympia to serve these loads is the 500-kV transmission line from Paul substation. An outage of this 500-kV source to Olympia would result in a voltage collapse during extra heavy winter load conditions. The Olympic Peninsula transmission system has been pushed to its limit with the use of shunt capacitors. A total of approximately 20 capacitor groups amounting to approximately 900 MVAR are already installed. A second 500-kV source is needed to solve the voltage collapse problem as early as 2003. However, yet another shunt capacitor group (?? YOU SAID ABOVE THAT THE SYSTEM HAS BEEN PUSHED TO ITS LIMIT) is being added in 2003 to delay the need for this project until 2005. In addition, a double-line outage of the 230-kV double-circuit line from Olympia to Shelton would result in a total loss of the Olympic Peninsula during normal winter load. The proposed reinforcement will solve both of these problems (voltage collapse and loss of load for n-2 outage) and reinforce the Olympic Peninsula region.

Limiting Outages Addressed

- Olympia 500/230-kV transformer
- Paul-Olympia 500-kV line
- Olympia-Shelton 230-kV double line
- Olympia 230-kV breaker failure

Benefit - -Load Area Service

This project will prevent these outages from impacting service to the Olympic Peninsula by providing a second source of power to the Peninsula from Paul Substation. This project will also increase the load service capability to the Olympic Peninsula under non-outage conditions as well as mitigate or delay other system upgrades that would be needed in the future if this project were not built.

Business Case

This project provides the capacity to carry additional projected normal winter load in the Olympic Peninsula area in compliance with NERC/WECC Planning Standards for Category A-C outages. For the purpose of this analysis revenues are based on 1.8% load growth at 26 MW/year capping at 338 MW in 2019. In the Table below, Alternative 1 is the proposed plan and Alternative 2 is moving the 500/230-kV transformer to Olympia (see below).

Alternative	Revenue($M)	Costs($M)	Net PV	B/C	Repayment Years	In Service	Life
1	21.6	29.3	(7.8)	0.74	20	2006	2040
2	21.6	27.2	(5.7)	0.79	19	2006	2040
1 (0.9%)	14.4	34.1	(19.7)	0.42	31	2006	2040

WHAT ARE ALTERNATIVES 1&2. SEE BOTH COMMENTS ON G10 TABLE.

Risk

Repayment of this project is based on load growth in the Olympic Peninsula area. The benefit to cost ratio (B/C) of Alternative 1 is less than one for a 9% discount rate but would equal one for a discount adjusted to 6.65% indicating a comparable return on investment of 6.65% over the 34 year life of this project. With the BPA financing rate of 6.75%, an inflation rate of 2.64% and the expected load growth rate of 1.8% the repayment period is estimated to be 20 years. For a reduced growth rate of 0.9% the repayment period is estimated to be 31 years.

SEE COMMENTS ON G10 TABLE

Project Description

- Build approximately 13.8 miles of 500-kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to the Shelton 500 kV yard. The line will be routed on the existing Olympia-Shelton right of way. Cut the Paul-Satsop 500 kV line at corridor intersection and connect the Paul end to new 500 kV line to Shelton.
- Remove Olympia-Shelton 115 kV line #1 from Olympia to Dayton Tap.
- Construct a 500 kV yard approximately 1 mile south of the existing Shelton substation, move Satsop 500/230 kV transformer to this location and tie it to Shelton 230 kV bus via 1 mile long 230 kV line.
- Build approximately 6 miles of new 230 kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to Olympia substation. Connect this new line to Satsop end of cut Paul-Satsop 500 kV line.

Alternatives Considered

- Move Satsop 500/230 kV transformer to Olympia substation and terminate the Paul-Satsop 500 kV line at Olympia.
- 400-600 MW of load tripping for the Olympia – Shelton 230 kV double circuit line outage.
- No build alternative – Do Nothing
- Non Transmission Alternatives

No-Build Alternative – Do Nothing

(a) The following information applies to loss of load for N-1 contingencies if the transmission system is not reinforced:

- 2 year MTBF for N-1 Paul-Olympia 500 kV line with average and maximum outage durations of 1.25 hours and 6.7 hours respectively
- 100 year MTBF for the Olympia 500/230 transformer and 2 week replacement time.
- required load curtailment for either outage increases by 26 MW yearly starting in 2010.

The probability of loss of load increases year by year related to the amount of time in the year the load is above the design limit. For example, assuming ~~a figure of~~ 5% of time

above this limit, the probability of loss of load for the line would be (1/2 + 1/100)(0.05) = 0.025 for a net MTBF of about 40 years between events.
I'M NOT FOLLOWING THIS CALCULATION

(b) The following information was used to estimate the probability of loss of load for N-2 contingencies if the transmission system is not reinforced:

- 9.3 year MTBF for N-2 outage of Olympia – Shelton 230 kV lines 3 and 4
- 0.018 breaker failures/year for any of eight breakers at Olympia
- load distributions from the past five years

Based on this we can expect to lose the entire Olympic Peninsula load (forecasted at 1170 MW for normal winter peak and 600 MW for summer peak in 2003-2004) about every 8 years in the winter. Risk of loss of load in the summer is very low. These impacts would be expected to be larger as load grows in the area. Based on the current system, for the double circuit outage we can supply 615 MW in the winter and 490 MW in the summer. Not considered in this analysis was the 500/230 kV transformer outage rate of once per 100 years.

Non-Transmission Alternatives
As possible non-transmission alternatives, BPA considered both the implementation of energy conservation measures to reduce demand on the transmission system, as well as load curtailment during outage conditions. Included in this consideration were the results of a report entitled "Expansion of BPA Transmission Planning Capabilities," Energy and Environmental Economics, Nov. 2001 (available at <http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm>). These measures could cost-effectively defer the need under N-1 contingencies, although they ~~can not~~cannot address the N-2 problems. BPA will further consider non-transmission alternatives before proceeding with this project.

DID YOU ALSO CONSIDER GAS TURBINS? EXPLAIN YOU ANSWER.

Decision
BPA chose the preferred transmission plan because it outperforms the Olympia option for both N-2 critical outages for essentially the same present worth cost without O&M expenses included. O&M costs would be higher for the Olympia option based on the amount of extra equipment that would be needed at the Olympia substation. The Olympia option would require major 230 kV work at the Olympia substation, including expansion of the 230 kV yard. Land would also have to be purchased around the 500 kV yard for 230 kV line routing into the 230 kV bus. Some of the line routing into the 230 kV bus may not even be physically possible based on current line routing, tower and road locations, land needs and right-of-way widths. The Shelton option has 8 MW less losses than the Olympia option based on 1170 MW of load, which is equivalent to normal winter load in 2002-03. These losses will increase with increases in load. The Shelton option would leave the system better prepared for the future. It is a robust choice under lower load growth and presents minimal business risk. BPA will further consider non-transmission alternatives before proceeding with this project.

I KNOW I WOULD HAVE A VERY HARD TIME SELLING ANYTHING TO MANAGEMENT WITH B/C<1. SO, SINCE THE B/C<1 YOU NEED TO JUSTIFY WHY THE DO NOTHING ISN'T APPROPRIATE.

SEE COMMENTS ON G10.

Energization Date: Fall 2006
Estimated Cost: $23-26 M

G13. Paul – Troutdale 500-kV Line

Background
The existing I-5 corridor transmission system is limited to:

- 2400 MW North of Allston by a double Paul – Allston 500-kV line outage
- 1650 MW South of Allston by the Allston – Keeler 500-kV line outage

With new generation projects proposed in the area, the existing system is not adequate to provide transmission service to most new generating projects on a firm basis, likely resulting in generation curtailments.

At present, the double Paul – Allston 500-kV line outage requires 2850 MW generation dropping and opening of both Chehalis – Longview 230-kV line that run in parallel to the Paul – Allston line. This sectionalizing removes the northern feed into Portland metro area, resulting in load service only from the east side through Ostrander. Sectionalizing greatly reduces reactive margins in the system, which will become a limiting factor as load grows in Portland area. Sectionalizing was also shown to degrade transient stability performance.

Currently, the Allston – Keeler 500-kV line outage requires generation dropping up to 2850 MW to prevent thermal overloads. Historic data indicates that there were 19 line outages in the past 16 years, mostly cased either by lightning hits or trees. It is very desirable to reduce generation dropping amount for a single contingency because .... WHAT?

This project is being taken through the WECC Regional Planning process.

Limiting Outages Addressed
Paul – Allston 500-kV double line
Allston – Keeler 500-kV line
Keeler – Pearl 500-kV line
Keeler breaker failure

Benefits

Table 1. Generation projects proposed in the area affecting transmission needs:

Project	Capacity	Energization	North of Allston	South of Allston
Napavine	600	11/1/03	More stress	More stress
Grays Harbor I	630	6/1/03	More stress	More stress
Longview – Enron	300	7/1/03	Less stress	More stress
Mint Farm	280	5/1/03	Less stress	More stress
Summit	530	11/1/03	Less stress	More stress
Big Hanaford	250	1/1/02	More stress	More stress
Port Westward	650	12/31/03	Less stress	More stress
Centralia efficiency	+ 70	Done	More stress	More stress
Grays Harbor II	630	11/1/04	More stress	More stress

Port Vancouver	700	6/1/05	Less stress	Less stress

It is evident that new generation will greatly increase stress the constrained I-5 paths. The existing system is not adequate to provide transmission service to most generating projects on firm basis, very likely resulting in generation curtailments. The new 500-kV line is expected to provide firm transmission rights for the proposed projects in the area.

A. Transfer Increase

It is expected that South of Allston limit will increase from 1650 MW to 2,700 – 2,900 MW. The new line will eliminate or greatly reduce the need for generation dropping for N-1 outages. The time to thermal overload will allow to ramp down generation of dropping. Upgrades of parallel 115-kV and 230-kV lines may be required to get the full capacity.

B. Load Service in Winter Conditions

Studies are under way.

Business Case
This project is driven by requests for long-term firm transmission by new generation and imports. Parties requesting transmission would be expected to fund the upgrade consistent with FERC policy.

Risk
The risk associated with this project is small because the generators will be expected to finance the transmission investment and/or commit to long-term transmission service.

Project Description
At present time, the plan of service is not fully defined. Two conceptual options have been considered and studied for electrical performance. Alternative #1 includes a 500-kV line from near Longview to Troutdale, and alternative #2 is a 500-kV line from near Longview to Pearl.

Decision
No preferred alternative is proposed at this time. The project will be returned to the Technical Review Committee for consideration in 2003 following the WECC Regional Planning Process.

Energization Date: **Fall 2005**
Estimated Cost: **$117-155 M**

G14. North of John Day/Portland Area Reinforcement – (Loop the Hanford-Ostrander 500-kV line into Big Eddy)

Background
The proposed new generation additions around the McNary area along with the new McNary-John Day 500-kV line will increase the stress across the North of John Day and the flow between John Day and Big Eddy. This project will relieve some of the North of John Day constraint and reinforce the transmission between John Day and Big Eddy. In addition, this project will also reinforce the bulk load serving capability into the greater Portland area. During abnormal cold weather, an outage of the Bid Eddy-Ostrander 500-kV line results in voltage collapse in the Portland area. This Project will in effect create a second Big Eddy – Ostrander 500-kV line and increase the load serving capability to the Portland area.

Limiting Outages Addressed
Ashe-Marion/Slatt-Buckley 500-kV double line loss (summer)
John Day-Big Eddy 500-kV double line loss (summer)
Slatt 500-kV breaker failures (summer)
Big Eddy-Ostrander 500-kV line (winter)
Pearl 500-kV breaker failures (winter)

Benefit – Congestion Relief and Load Area Support
This project will increase the North of John Day capability by approximately 250-300 MW and increase the capability between John Day and Big Eddy by approximately 600-700 MW. This project also reinforces the bulk grid to serve greater Portland area load and eliminate the need for building second Big Eddy-Ostrander 500-kV line.

Business Case
The primary drivers of this project ~~is~~are North to South network transfers and provide additional network capacity for service to the Portland area load. The estimated cost recovery of this project at current rates and for the alternatives considered is over 35 years. In view of the long payback period lower cost alternatives or deferral will be considered.

Risk
The benefit ascribed to this project for the Portland area load is related to the timing of the Paul – Troutdale project ~~which~~that in part serves this need. The portion of benefits ascribed to intertie support will be beneficial at the time the project goes into service but is not sufficient alone to ensure full cost recovery. Risk that costs will not be recovered for this project as proposed at this point is high.

Project Description

- This project consists of constructing approximately 16.5 miles of 500-kV double circuit line to the Columbia River crossing and approximately 18 miles of single circuit 500-kV line to Big Eddy and 2 miles of line to John Day.

- Develop a new 500-kV switching station next to the existing Hanford (Wautoma) – Ostrander 500-kV line and loop in the Hanford-Ostrander line into the new switching station.
- Add terminals at Big Eddy and John Day to terminate the new lines.

Preliminary Alternatives

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit.

- Loop in the existing Hanford-Ostrander 500-kV line into Big Eddy by building 34.5 miles of 500-kV double circuit and build a third 20miles of single circuit 500-kV line between John Day and Big Eddy

Decision

No preferred alternative is proposed at this time. The project may be returned to the ~~Techncial~~Technical Review Committee for consideration in 2003 following further analysis.

Energization Date: **Spring 2006**
Estimated Cost: **$70-90M**

Wright, April E - LC-7

From: Jim Eden [Jim_Eden@pgn.com]
Sent: Tuesday, July 02, 2002 10:44 AM
To: wmittelstadt@bpa.gov
Subject: ITRG Draft Report

Three comments and a request:

I believe the Port Vancouver 700 MW project has been cancelled, and should be removed from the list on page C-7.

In the middle of page C-7, the statement on reduceing the need for generation dropping for N-1 needs to be completed.

On page 4 of the report (relative to G-13), it is stated that BPA should complete details of the plan of service over the next 60 days. On page C-8, under Decision, it is stated that the project will be returned to the TRC for consideration in 2003. I think that it is extremely important to initiate the (public process) study work ASAP as was intended last February. I think it is in the regions best interest to get on top of the plan BEFORE this becomes an operating issue. If a preferred plan is identified in the next couple of months, we can't sit on this until 2003. I believe that some customers may wish to commit by early 2003 and thus, the regional review (WECC and ITRC) needs to be completed by early 2003. This timing issue (or process issue) should be reflected somewhere on page C-8.

And, my request, can we initiate the G-13 review process ASAP. I think we need to pick a day and notice a meeting. We need to identify the needs, the technical goals, people to assist in studies (I volunteer), the timeline, etc.

Thank you for the opportunity to participate in this important work. Please keep me posted.

Jim Eden, PE
Consulting Transmission Engineer
Portland General Electric
121 SW Salmon St
Portland, OR 97204

503 464-7031 office
503 819-7722 cell
503 464-2538 fax

jim_eden@pgn.com

From: Waples, Scott [scott.waples@avistacorp.com]
Sent: Monday, July 15, 2002 3:49 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Subject: RE: ITRG Draft Report

I don't other than maybe the SIGWG meeting on the 31st???

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Tuesday, July 09, 2002 12:28 PM
To: 'Waples, Scott'
Subject: RE: ITRG Draft Report

Scott

As soon as this contains any changes or additions I will arrange to get signatures. Do you know of any upcoming meeting where some of these folks will be represented?

Bill

-----Original Message-----
From: Waples, Scott [mailto:scott.waples@avistacorp.com]
Sent: Monday, July 08, 2002 4:06 PM
To: 'Mittelstadt, Bill - TOM-PPO2-2'
Subject: RE: ITRG Draft Report

Bill-
It looks as if I (and others)am already a signatory to this newest draft of this report. Will we get a chance to actually sign off on it?
Thanks-
Scott

-----Original Message-----
From: Mittelstadt, Bill - TOM-PPO2-2 [mailto:wmittelstadt@bpa.gov]
Sent: Monday, July 01, 2002 12:48 PM
To: Mittelstadt, Bill - TOM-PPO2-2; 'Brattebo, Scott'; 'Carr, Geoff'; Carter, Lawrence D - TOP-PPO2-2; 'Eden, Jim'; 'Elizeh, Edison'; 'Goddard, Richard'; 'Groce, Ed'; Horvath, Julius G - TOP-PPO2-2; 'Johnson, Don'; 'Juj, Hardev'; Keenan, Gerald - TOP-PPO2-2; 'Kinney, Scott'; Kosterev, Dmitry - TOM-PPO2-2; Landauer, Marv - TOM-PPO2-2; 'Leland, John'; 'Lu, Franklin'; 'Martinsen, John'; 'Morris, Ken'; 'Phillips, John'; Quinata, John F - TOE-PPO1-2; 'Reedy, Dana'; Rodrigues, Melvin - TOP-PPO2-2; 'Rust, Jerry'; Rydell, Kendall - TOP-PPO2-2; 'Schellberg, Ron'; 'Seabrook, Joe'; Silverstein, Brian L - TOP-PPO2-2; Stadler, Larry W - TOP-PPO2-2; VanZandt, Vickie - TO; 'Waples, Scott'
Cc: Haner, John - TOM-PPO2-2
Subject: RE: ITRG Draft Report

Hello again,

Please return any comments on this draft material that was submitted to you by July 10 so that the report can be finalized.

Thanks

Bill Mittelstadt

<<William A Mittelstadt (E-mail).vcf>>
> -----Original Message-----
> From: Mittelstadt, Bill - TOM-PPO2-2
> Sent: Monday, June 24, 2002 8:56 AM
> To: Brattebo, Scott; Carr, Geoff; CARTER, LAWRENCE; Eden, Jim; Elizeh,
> Edison; 'Goddard, Richard'; Groce, Ed; HORVATH, JULIUS; Johnson, Don; Juj,
> Hardev; KEENAN, GERALD; Kinney, Scott; KOSTEREV, DMITRY; LANDAUER, MARVIN;
> Leland, John; Lu, Franklin; Martinsen, John; Morris, Ken; Phillips, John;
> QUINATA, JOHN; Reedy, Dana; RODRIGUES, MELVIN; Rust, Jerry; RYDELL,
> KENDALL; Schellberg, Ron; Seabrook, Joe; SILVERSTEIN, BRIAN; STADLER,
> LAWRENCE; VANZANDT, VICKIE; Waples, Scott
> Cc: Mittelstadt, Bill - TOM-PPO2-2; Haner, John - TOM-PPO2-2
> Subject: ITRG Draft Report
>
> Dear Technical Review Committee Participants
>
> This year we conducted the second annual review of BPA's proposed
> transmission infrastructure projects. BPA offered four projects for
> consideration. Based on your feedback, BPA recommends that two of the
> projects be advanced: G10 (Portland Area Additions) for construction and
> G12 (Olympic Peninsula Reinforcement) for environmental review. The
> other two projects will be brought forward again.
>
> Attached please find a draft report based on the format from last year.
> It summarizes BPA's proposals and our sense of the Committee views. We
> have tried to provide the additional information you requested and
> incorporate your feedback. Please feel free to edit the documents and
> return them to me. Depending on the response we can finalize the
> documents based on your edits, set up a conference call if further
> discussion is warranted, or set up a another meeting in Portland if that's
> what you want to do.
>
> Our intention is to repeat the process with additional proposals next
> year.
>
> I appreciate the time you have taken to provide critical feedback and I
> look forward to hearing from you.
>
>
> Regards
> Bill
>
>
>
> << File: William A Mittelstadt (E-mail).vcf >> << File: Cover Letter.doc
> >> << File: Report Draft.doc >> << File: Appendix A.doc >> << File:
> Appendix B.doc >> << File: Appendix C.doc >> << File: Appendix D.doc >>
> << File: Appendix E.doc >>

Sent

Seifert, Roger - DC/WASH

From: BPA National Relations
Sent: Thursday, July 11, 2002 2:57 PM
To: BALL, Crystal; COHEN, RACHELLE; Jones, Sheron - KN; MOORE, N'Nekka; Seifert, Roger - KN; STIER, JEFFREY; Williams, Laura
Subject: FW: BPA Borrowing Authority

Follow Up Flag: For Your Information
Flag Status: Flagged

-----Original Message-----
From: **BPA National Relations**
Sent: Thursday, July 11, 2002 14:56
To: Becker-Dippmann, Angela (Sen. Cantwell); Benner, Janine (Rep. Blumenauer); Bonlender, Brian (Rep. Inslee); Bridges, Karen (Sen. Baucus); Cabasco, Vergi (Rep. Dunn); Cassidy, Ed (Rep. Hastings #2); Clapp, Doug (Sen. Murray); Ende, Ken (Sen. Burns); Ferguson, Alisa (Rep. Baird); Flachbart, Amy (Rep. Nethercutt); Flint, Aaron (Sen. Burns); Griffin, Paul (Rep. Walden); Heggem, Chris (Sen. Burns); Hollier, Will (Senator Crapo); Huckleberry, Chris (Rep. Hooley); Hughes, Sean (Rep. McDermott); Johnson, Cameron (Re. Wu); Kadlec, Ken (Rep. McDermott #2); Loy, John (Rep. Smith); Markey, Jeff (Rep. Hastings #1); O'Connor, George (Sen. Craig); Revier, Jani (Rep. Otter); Sheinkman, Joshua (Sen. Wyden); Tidwell, Troy (Rep. Walden); Triplett, Jordan (Rep. Smith); Tucker, Brandon (Rep. Simpson); Turner, Lesley (Rep. Dicks); Vinson, Tom (Rep. DeFazio); West, Valerie (Sen. Smith)
Subject: BPA Borrowing Authority

The following language was included in the report accompanying the House Energy and Water Appropriations bill, which was reported from subcommittee yesterday. The committee's intent was to ensure that BPA borrowing authority would be a conference-able item for the purposes of the Energy and Water Appropriations bill, without prejudging the outcome of the Energy bill conference.

"The Administration has submitted a legislative proposal to increase the current Bonneville borrowing authority by $700,000,000, for new total borrowing authority of $4,450,000,000. The Committee recommendation does not include this additional borrowing authority at this time because the matter is presently committed to the House-Senate conference on energy legislation."

Jeff Stier

202-586-5640

Seifert, Roger - DC/WASH released

From: Cohen, Ashley - KN-DC
Sent: Thursday, July 11, 2002 9:45 AM
To: Ball, Crystal A - KN-DC; Seifert, Roger - KN-DC
Subject: FW: BPA Borrowing Authority

this is what we got on borrowing authority . .
-----Original Message-----
From: Stier, Jeffrey K - KN-DC
Sent: Thursday, July 11, 2002 9:43 AM
To: Cohen, Ashley - KN-DC
Subject: FW: BPA Borrowing Authority

Please distribute internally with a note explaining that this will make borrowing authority a conference-able item
-----Original Message-----
From: Flachbart, Amy [mailto:Amy.Flachbart@mail.house.gov]
Sent: Thursday, July 11, 2002 9:40 AM
To: Turner, Lesley; Jeff Stier (E-mail)
Subject: FW: BPA Borrowing Authority

-----Original Message-----
From: Cook, Kevin
Sent: Thursday, July 11, 2002 9:36 AM
To: Flachbart, Amy
Subject: RE: BPA Borrowing Authority

AMY - This is the paragraph in report language on BPA borrowing authority. It is intended merely as a neutral placeholder so we can come back to the issue in conference. I worry that any more direct statement (i.e., that we intend to address borrowing authority in conference) might bring some Energy and Commerce Cmte opposition out of the woodwork. If your boss feels the need for something more affirmative, we can always do a colloquy with Chairman Callahan when we get to the House floor.

The Administration has submitted a legislative proposal to increase the current Bonneville borrowing authority by $700,000,000, for new total borrowing authority of $4,450,000,000. The Committee recommendation does not include this additional borrowing authority at this time because the matter is presently committed to the House-Senate conference on energy legislation.

Sent

Seifert, Roger - DC/WASH

From: Seifert, Roger - KN-DC
Sent: Friday, July 26, 2002 11:20 AM
To: 'Palmer, William'
Cc: Stier, Jeffrey K - KN-DC; Curtis, Jim - DF-2; Hawken, Mary - DFF-2; Roach, Randy A - L-7; Majkut, Paul S - LC-7
Subject: Wyden BPA Borrowing Authority Amendment

Attached is an electronic copy of the technical fixes to the Senate Legislative Council drafted Wyden Amendment that we suggested at the time the bill was being considered. As I have indicated several previous times we were trying to keep our Treasury borrowing relationship (to Treasury and not direct to market) as it has historically been. As I have also indicated previously, I have also had several conversations with Paula Farrell to assure her we wanted to do that, but were not successful. Since you asked for the Senate passed Wyden Amendment, Jeff and I wanted you to have these needed changes to avoid changing our relationship with Treasury and how our borrowing interest rates are determined.

Borrowing Authority Increase.d...

SA 3230. Mr. WYDEN submitted an amendment intended to be proposed to amendment SA 2917 proposed by Mr. DASCHLE (for himself and Mr. BINGAMAN) to the bill (S. 517) to authorize funding the Department of Energy to enhance its mission areas through technology transfer and partnerships for fiscal years 2002 through 2006, and for other purposes; which was ordered to lie on the table; as follows:

On page 62, between lines 3 and 4, insert the following:

SEC. 2__. BONNEVILLE POWER ADMINISTRATION BONDS.

Section 13 of the Federal Columbia River Transmission System Act (16 U.S.C. 838k) is amended--

(1) by striking the section heading and all that follows through ``(a) The Administrator" and inserting the following:

``**SEC. 13. BONNEVILLE POWER ADMINISTRATION BONDS.**

``**(a) BONDS.**--

``**(1) IN GENERAL.**--The Administrator"; and

(2) by adding at the end the following:

``**(2) ADDITIONAL BORROWING AUTHORITY.**--In addition to the borrowing authority of the Administrator authorized under paragraph (1) or any other provision of law, an additional $1,300,000,000 is made available, as provided in this section, to remain outstanding at any ~~1~~ one time--

``(A) to provide funds to assist in financing the construction, acquisition, and replacement of the transmission system of the Bonneville Power Administration; and

``(B) to implement the authorities of the Administrator under the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839 et seq.).".

Sent

Seifert, Roger - DC/WASH

From: Seifert, Roger - KN-DC
Sent: Friday, July 26, 2002 11:25 AM
To: 'Palmer, William'
Subject: FW: Wyden BPA Borrowing Authority Amendment

Importance: High

Wyden Borrowing Amendment.htm

Per your fast request Bill, her is a copy of the Senate passed Wyden BPA borrowing authority amendment. This amendment was to H.R. 4 with the engrossed amendments of the Senate.

H.R.4

Energy Policy Act of 2002 (Engrossed Amendment as Agreed to by Senate)

SEC. 272. BONNEVILLE POWER ADMINISTRATION BONDS.

Section 13 of the Federal Columbia River Transmission System Act (16 U.S.C. 838k) is amended--

(1) by striking the section heading and all that follows through `(a) The Administrator' and inserting the following:

`SEC. 13. BONNEVILLE POWER ADMINISTRATION BONDS.

`(a) BONDS-

`(1) IN GENERAL- The Administrator'; and

(2) by adding at the end the following:

`(2) ADDITIONAL BORROWING AUTHORITY- In addition to the borrowing authority of the Administrator authorized under paragraph (1) or any other provision of law, an additional $1,300,000,000 is made available, to remain outstanding at any one time--

`(A) to provide funds to assist in financing the construction, acquisition, and replacement of the transmission system of the Bonneville Power Administration; and

`(B) to implement the authorities of the Administrator under the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839 et seq.).'.

TITLE III--HYDROELECTRIC RELICENSING

SEC. 301. ALTERNATIVE CONDITIONS AND FISHWAYS.

(a) ALTERNATIVE MANDATORY CONDITIONS- Section 4 of the Federal Power Act (16 U.S.C. 797) is amended by adding at the end the following:

`(h)(1) Whenever any person applies for a license for any project works within any reservation of the United States under subsection (e), and the Secretary of the department under whose supervision such reservation falls (in this subsection referred to as the `Secretary') shall deem a condition to such license to be necessary under the first proviso of such section, the license applicant may propose an alternative condition.

`(2) Notwithstanding the first proviso of subsection (e), the Secretary of the department under whose supervision

the reservation falls shall accept the proposed alternative condition referred to in paragraph (1), and the Commission shall include in the license such alternative condition, if the Secretary of the appropriate department determines, based on substantial evidence provided by the license applicant, that the alternative condition--

`(A) provides for the adequate protection and utilization of the reservation; and

`(B) will either--

`(i) cost less to implement, or

`(ii) result in improved operation of the project works for electricity production as compared to the condition initially deemed necessary by the Secretary.

`(3) The Secretary shall submit into the public record of the Commission proceeding with any condition under subsection (e) or alternative condition it accepts under this subsection a written statement explaining the basis for such condition, and reason for not accepting any alternative condition under this subsection, including the effects of the condition accepted and alternatives not accepted on energy supply, distribution, cost, and use, air quality, flood control, navigation, and drinking, irrigation, and recreation water supply, based on such information as may be available to the Secretary, including information voluntarily provided in a timely manner by the applicant and others.

`(4) Nothing in this subsection shall prohibit other interested parties from proposing alternative conditions.'

(b) ALTERNATIVE FISHWAYS- Section 18 of the Federal Power Act (16 U.S.C. 811) is amended by--

(1) inserting `(a)' before the first sentence; and

(2) adding at the end the following:

`(b)(1) Whenever the Secretary of the Interior or the Secretary of Commerce prescribes a fishway under this section, the license applicant or the licensee may propose an alternative to such prescription to construct, maintain, or operate a fishway.

`(2) Notwithstanding subsection (a), the Secretary of the Interior or the Secretary of Commerce, as appropriate, shall accept and prescribe, and the Commission shall require, the proposed alternative referred to in paragraph (1), if the Secretary of the appropriate department determines, based on substantial evidence provided by the licensee, that the alternative--

`(A) will be no less protective of the fish resources than the fishway initially prescribed by the Secretary; and

`(B) will either--

`(i) cost less to implement, or

`(ii) result in improved operation of the project works for electricity production as compared to the fishway initially prescribed by the Secretary.

`(3) The Secretary shall submit into the public record of the Commission proceeding with any prescription under subsection (a) or alternative prescription it accepts under this subsection a written statement explaining the basis for such prescription, and reason for not accepting any alternative prescription under this subsection, including the effects of the prescription accepted or alternative not accepted on energy supply, distribution, cost, and use,

air quality, flood control, navigation, and drinking, irrigation, and recreation water supply, based on such information as may be available to the Secretary, including information voluntarily provided in a timely manner by the applicant and others.

`(4) Nothing in this subsection shall prohibit other interested parties from proposing alternative prescriptions.'.

(c) TIME OF FILING APPLICATION- Section 15(c)(1) of the Federal Power Act (16 U.S.C. 808(c)(1)) is amended by striking the first sentence and inserting the following:

`(1) Each application for a new license pursuant to this section shall be filed with the Commission--

`(A) at least 24 months before the expiration of the term of the existing license in the case of licenses that expire prior to 2008; and

`(B) at least 36 months before the expiration of the term of the existing license in the case of licenses that expire in 2008 or any year thereafter.'.

TITLE IV--INDIAN ENERGY

SEC. 401. COMPREHENSIVE INDIAN ENERGY PROGRAM.

Title XXVI of the Energy Policy Act of 1992 (25 U.S.C. 3501-3506) is amended by adding after section 2606 the following:

`SEC. 2607. COMPREHENSIVE INDIAN ENERGY PROGRAM.

`(a) DEFINITIONS- For purposes of this section--

`(1) the term `Director' means the Director of the Office of Indian Energy Policy and Programs established by section 217 of the Department of Energy Organization Act, and

`(2) the term `Indian land' means--

`(A) any land within the limits of an Indian reservation, pueblo, or rancheria;

`(B) any land not within the limits of an Indian reservation, pueblo, or rancheria whose title is held--

`(i) in trust by the United States for the benefit of an Indian tribe,

`(ii) by an Indian tribe subject to restriction by the United States against alienation, or

`(iii) by a dependent Indian community; and

`(C) land conveyed to an Alaska Native Corporation under the Alaska Native Claims Settlement Act.

`(b) INDIAN ENERGY EDUCATION PLANNING AND MANAGEMENT ASSISTANCE- (1) The Director shall establish programs within the Office of Indian Energy Policy and Programs to assist Indian tribes in meeting their energy education, research and development, planning, and management needs.

`(2) The Director may make grants, on a competitive basis, to an Indian tribe for--

`(A) renewable energy, energy efficiency, and conservation programs;

`(B) studies and other activities supporting tribal acquisition of energy supplies, services, and facilities;

`(C) planning, constructing, developing, operating, maintaining, and improving tribal electrical generation, transmission, and distribution facilities; and

`(D) developing, constructing, and interconnecting electric power transmission facilities with transmission facilities owned and operated by a Federal power marketing agency or an electric utility that provides open access transmission service.

`(3) The Director may develop, in consultation with Indian tribes, a formula for making grants under this section. The formula may take into account the following--

`(A) the total number of acres of Indian land owned by an Indian tribe;

`(B) the total number of households on the Indian tribe's Indian land;

`(C) the total number of households on the Indian tribe's Indian land that have no electricity service or are under-served; and

`(D) financial or other assets available to the Indian tribe from any source.

`(4) In making a grant under paragraph (2), the Director shall give priority to an application received from an Indian tribe that is not served or is served inadequately by an electric utility, as that term is defined in section 3 (4) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2602(4)), or by a person, State agency, or any other non-Federal entity that owns or operates a local distribution facility used for the sale of electric energy to an electric consumer.

`(5) There are authorized to be appropriated to the Department of Energy such sums as may be necessary to carry out the purposes of this section.

`(6) The Secretary is authorized to promulgate such regulations as the Secretary determines to be necessary to carry out the provisions of this subsection.

`(c) LOAN GUARANTEE PROGRAM-

`(1) AUTHORITY- The Secretary may guarantee not more than 90 percent of the unpaid principal and interest due on any loan made to any Indian tribe for energy development, including the planning, development, construction, and maintenance of electrical generation plants, and for transmission and delivery mechanisms for electricity produced on Indian land. A loan guaranteed under this subsection shall be made by--

`(A) a financial institution subject to the examination of the Secretary; or

`(B) an Indian tribe, from funds of the Indian tribe, to another Indian tribe.

`(2) AVAILABILITY OF APPROPRIATIONS- Amounts appropriated to cover the cost of loan guarantees shall be available without fiscal year limitation to the Secretary to fulfill obligations arising under this subsection.

`(3) AUTHORIZATION OF APPROPRIATIONS- (A) There are authorized to be appropriated to the Secretary such sums as may be necessary to cover the cost of loan guarantees, as defined by section 502(5) of the Federal Credit Reform Act of 1990 (2 U.S.C. 661a(5)).

`(B) There are authorized to be appropriated to the Secretary such sums as may be necessary to cover the administrative expenses related to carrying out the loan guarantee program established by this subsection.

`(4) LIMITATION ON AMOUNT- The aggregate outstanding amount guaranteed by the Secretary of Energy at any one time under this subsection shall not exceed $2,000,000,000.

`(5) REGULATIONS- The Secretary is authorized to promulgate such regulations as the Secretary determines to be necessary to carry out the provisions of this subsection.

`(d) INDIAN ENERGY PREFERENCE- (1) An agency or department of the United States Government may give, in the purchase of electricity, oil, gas, coal, or other energy product or by-product, preference in such purchase to an energy and resource production enterprise, partnership, corporation, or other type of business organization majority or wholly owned and controlled by a tribal government.

`(2) In implementing this subsection, an agency or department shall pay no more than the prevailing market price for the energy product or by-product and shall obtain no less than existing market terms and conditions.

`(e) EFFECT ON OTHER LAWS- This section does not--

`(1) limit the discretion vested in an Administrator of a Federal power marketing agency to market and allocate Federal power, or

`(2) alter Federal laws under which a Federal power marketing agency markets, allocates, or purchases power.'.

SEC. 402. OFFICE OF INDIAN ENERGY POLICY AND PROGRAMS.

Title II of the Department of Energy Organization Act is amended by adding at the end the following:

`OFFICE OF INDIAN ENERGY POLICY AND PROGRAMS

`SEC. 217. (a) There is established within the Department an Office of Indian Energy Policy and Programs. This Office shall be headed by a Director, who shall be appointed by the Secretary and compensated at the rate equal to that of level IV of the Executive Schedule under section 5315 of title 5, United States Code.

`(b) The Director shall provide, direct, foster, coordinate, and implement energy planning, education, management, conservation, and delivery programs of the Department that--

`(1) promote tribal energy efficiency and utilization;

`(2) modernize and develop, for the benefit of Indian tribes, tribal energy and economic infrastructure related to natural resource development and electrification;

`(3) preserve and promote tribal sovereignty and self determination related to energy matters and energy deregulation;

`(4) lower or stabilize energy costs; and

`(5) electrify tribal members' homes and tribal lands.

`(c) The Director shall carry out the duties assigned the Secretary or the Director under title XXVI of the Energy Policy Act of 1992 (25 U.S.C. 3501 et seq.).'.

SEC. 403. CONFORMING AMENDMENTS.

(a) AUTHORIZATION OF APPROPRIATIONS- Section 2603(c) of the Energy Policy Act of 1992 (25 U.S.C. 3503(c)) is amended to read as follows:

`(c) AUTHORIZATION OF APPROPRIATIONS- There are authorized to be appropriated such sums as may be necessary to carry out the purposes of this section.'.

(b) TABLE OF CONTENTS- The table of contents of the Department of Energy Act is amended by inserting after the item relating to section 216 the following new item:

`Sec. 217. Office of Indian Energy Policy and Programs.'.

(c) EXECUTIVE SCHEDULE- Section 5315 of title 5, United States Code, is amended by inserting `Director, Office of Indian Energy Policy and Programs, Department of Energy.' after `Inspector General, Department of Energy.'.

SEC. 404. SITING ENERGY FACILITIES ON TRIBAL LANDS.

(a) DEFINITIONS- For purposes of this section:

(1) INDIAN TRIBE- The term `Indian tribe' means any Indian tribe, band, nation, or other organized group or community, which is recognized as eligible for the special programs and services provided by the United States to Indians because of their status as Indians, except that such term does not include any Regional Corporation as defined in section 3(g) of the Alaska Native Claims Settlement Act (43 U.S.C. 1602(g)).

(2) INTERESTED PARTY- The term `interested party' means a person whose interests could be adversely affected by the decision of an Indian tribe to grant a lease or right-of-way pursuant to this section.

(3) PETITION- The term `petition' means a written request submitted to the Secretary for the review of an action (or inaction) of the Indian tribe that is claimed to be in violation of the approved tribal regulations.

(4) RESERVATION- The term `reservation' means--

(A) with respect to a reservation in a State other than Oklahoma, all land that has been set aside or that has been acknowledged as having been set aside by the United States for the use of an Indian tribe, the exterior boundaries of which are more particularly defined in a final tribal treaty, agreement, executive order, Federal statute, secretarial order, or judicial determination;

(B) with respect to a reservation in the State of Oklahoma, all land that is--

(i) within the jurisdictional area of an Indian tribe, and

(ii) within the boundaries of the last reservation of such tribe that was established by treaty, executive order, or secretarial order.

(5) SECRETARY- The term `Secretary' means the Secretary of the Interior.

(6) TRIBAL LANDS- The term `tribal lands' means any tribal trust lands, or other lands owned by an Indian tribe that are within such tribe's reservation.

(b) LEASES INVOLVING GENERATION, TRANSMISSION, DISTRIBUTION OR ENERGY PROCESSING FACILITIES- An Indian tribe may grant a lease of tribal land for electric generation, transmission, or distribution facilities, or facilities to process or refine renewable or nonrenewable energy resources developed on tribal lands, and such leases shall not require the approval of the Secretary if the lease is executed under tribal regulations approved by the Secretary under this subsection and the term of the lease does not exceed 30 years.

(c) RIGHTS-OF-WAY FOR ELECTRIC GENERATION, TRANSMISSION, DISTRIBUTION OR ENERGY PROCESSING FACILITIES- An Indian tribe may grant a right-of-way over tribal lands for a pipeline or an electric transmission or distribution line without separate approval by the Secretary, if--

(1) the right-of-way is executed under and complies with tribal regulations approved by the Secretary and the term of the right-of-way does not exceed 30 years; and

(2) the pipeline or electric transmission or distribution line serves--

(A) an electric generation, transmission or distribution facility located on tribal land, or

(B) a facility located on tribal land that processes or refines renewable or nonrenewable energy resources developed on tribal lands.

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Sent

Seifert, Roger - DC/WASH

From: Seifert, Roger - KN-DC
Sent: Friday, July 26, 2002 12:10 PM
To: 'Kabat, Gale'
Subject: FW: Wyden BPA Borrowing Authority Amendment

Importance: High

FYI. This is what Carnes asked Weatherly for, which Weatherly asked Bill for, which Bill asked me for and you called while Bill was on the phone with me.

-----Original Message-----
From: Seifert, Roger - KN-DC
Sent: Friday, July 26, 2002 11:25 AM
To: 'Palmer, William'
Subject: FW: Wyden BPA Borrowing Authority Amendment
Importance: High

Wyden Borrowing Amendment.htm

Per your fast request Bill, her is a copy of the Senate passed Wyden BPA borrowing authority amendment. This amendment was to H.R. 4 with the engrossed amendments of the Senate.

H.R.4

Energy Policy Act of 2002 (Engrossed Amendment as Agreed to by Senate)

SEC. 272. BONNEVILLE POWER ADMINISTRATION BONDS.

Section 13 of the Federal Columbia River Transmission System Act (16 U.S.C. 838k) is amended--

(1) by striking the section heading and all that follows through `(a) The Administrator' and inserting the following:

`SEC. 13. BONNEVILLE POWER ADMINISTRATION BONDS.

`(a) BONDS-

`(1) IN GENERAL- The Administrator'; and

(2) by adding at the end the following:

`(2) ADDITIONAL BORROWING AUTHORITY- In addition to the borrowing authority of the Administrator authorized under paragraph (1) or any other provision of law, an additional $1,300,000,000 is made available, to remain outstanding at any one time--

`(A) to provide funds to assist in financing the construction, acquisition, and replacement of the transmission system of the Bonneville Power Administration; and

`(B) to implement the authorities of the Administrator under the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839 et seq.).'.

TITLE III--HYDROELECTRIC RELICENSING

SEC. 301. ALTERNATIVE CONDITIONS AND FISHWAYS.

(a) ALTERNATIVE MANDATORY CONDITIONS- Section 4 of the Federal Power Act (16 U.S.C. 797) is amended by adding at the end the following:

`(h)(1) Whenever any person applies for a license for any project works within any reservation of the United States under subsection (e), and the Secretary of the department under whose supervision such reservation falls (in this subsection referred to as the `Secretary') shall deem a condition to such license to be necessary under the first proviso of such section, the license applicant may propose an alternative condition.

`(2) Notwithstanding the first proviso of subsection (e), the Secretary of the department under whose supervision

the reservation falls shall accept the proposed alternative condition referred to in paragraph (1), and the Commission shall include in the license such alternative condition, if the Secretary of the appropriate department determines, based on substantial evidence provided by the license applicant, that the alternative condition--

`(A) provides for the adequate protection and utilization of the reservation; and

`(B) will either--

`(i) cost less to implement, or

`(ii) result in improved operation of the project works for electricity production as compared to the condition initially deemed necessary by the Secretary.

`(3) The Secretary shall submit into the public record of the Commission proceeding with any condition under subsection (e) or alternative condition it accepts under this subsection a written statement explaining the basis for such condition, and reason for not accepting any alternative condition under this subsection, including the effects of the condition accepted and alternatives not accepted on energy supply, distribution, cost, and use, air quality, flood control, navigation, and drinking, irrigation, and recreation water supply, based on such information as may be available to the Secretary, including information voluntarily provided in a timely manner by the applicant and others.

`(4) Nothing in this subsection shall prohibit other interested parties from proposing alternative conditions.'.

(b) ALTERNATIVE FISHWAYS- Section 18 of the Federal Power Act (16 U.S.C. 811) is amended by--

(1) inserting `(a)' before the first sentence; and

(2) adding at the end the following:

`(b)(1) Whenever the Secretary of the Interior or the Secretary of Commerce prescribes a fishway under this section, the license applicant or the licensee may propose an alternative to such prescription to construct, maintain, or operate a fishway.

`(2) Notwithstanding subsection (a), the Secretary of the Interior or the Secretary of Commerce, as appropriate, shall accept and prescribe, and the Commission shall require, the proposed alternative referred to in paragraph (1), if the Secretary of the appropriate department determines, based on substantial evidence provided by the licensee, that the alternative--

`(A) will be no less protective of the fish resources than the fishway initially prescribed by the Secretary; and

`(B) will either--

`(i) cost less to implement, or

`(ii) result in improved operation of the project works for electricity production as compared to the fishway initially prescribed by the Secretary.

`(3) The Secretary shall submit into the public record of the Commission proceeding with any prescription under subsection (a) or alternative prescription it accepts under this subsection a written statement explaining the basis for such prescription, and reason for not accepting any alternative prescription under this subsection, including the effects of the prescription accepted or alternative not accepted on energy supply, distribution, cost, and use,

air quality, flood control, navigation, and drinking, irrigation, and recreation water supply, based on such information as may be available to the Secretary, including information voluntarily provided in a timely manner by the applicant and others.

`(4) Nothing in this subsection shall prohibit other interested parties from proposing alternative prescriptions.'.

(c) TIME OF FILING APPLICATION- Section 15(c)(1) of the Federal Power Act (16 U.S.C. 808(c)(1)) is amended by striking the first sentence and inserting the following:

`(1) Each application for a new license pursuant to this section shall be filed with the Commission--

`(A) at least 24 months before the expiration of the term of the existing license in the case of licenses that expire prior to 2008; and

`(B) at least 36 months before the expiration of the term of the existing license in the case of licenses that expire in 2008 or any year thereafter.'.

TITLE IV--INDIAN ENERGY

SEC. 401. COMPREHENSIVE INDIAN ENERGY PROGRAM.

Title XXVI of the Energy Policy Act of 1992 (25 U.S.C. 3501-3506) is amended by adding after section 2606 the following:

`SEC. 2607. COMPREHENSIVE INDIAN ENERGY PROGRAM.

`(a) DEFINITIONS- For purposes of this section--

`(1) the term `Director' means the Director of the Office of Indian Energy Policy and Programs established by section 217 of the Department of Energy Organization Act, and

`(2) the term `Indian land' means--

`(A) any land within the limits of an Indian reservation, pueblo, or rancheria;

`(B) any land not within the limits of an Indian reservation, pueblo, or rancheria whose title is held--

`(i) in trust by the United States for the benefit of an Indian tribe,

`(ii) by an Indian tribe subject to restriction by the United States against alienation, or

`(iii) by a dependent Indian community; and

`(C) land conveyed to an Alaska Native Corporation under the Alaska Native Claims Settlement Act.

`(b) INDIAN ENERGY EDUCATION PLANNING AND MANAGEMENT ASSISTANCE- (1) The Director shall establish programs within the Office of Indian Energy Policy and Programs to assist Indian tribes in meeting their energy education, research and development, planning, and management needs.

~~*`(2) The Director may make grants, on a competitive basis, to an Indian tribe for--*~~

`(A) renewable energy, energy efficiency, and conservation programs;

`(B) studies and other activities supporting tribal acquisition of energy supplies, services, and facilities;

`(C) planning, constructing, developing, operating, maintaining, and improving tribal electrical generation, transmission, and distribution facilities; and

`(D) developing, constructing, and interconnecting electric power transmission facilities with transmission facilities owned and operated by a Federal power marketing agency or an electric utility that provides open access transmission service.

`(3) The Director may develop, in consultation with Indian tribes, a formula for making grants under this section. The formula may take into account the following--

`(A) the total number of acres of Indian land owned by an Indian tribe;

`(B) the total number of households on the Indian tribe's Indian land;

`(C) the total number of households on the Indian tribe's Indian land that have no electricity service or are under-served; and

`(D) financial or other assets available to the Indian tribe from any source.

`(4) In making a grant under paragraph (2), the Director shall give priority to an application received from an Indian tribe that is not served or is served inadequately by an electric utility, as that term is defined in section 3 (4) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2602(4)), or by a person, State agency, or any other non-Federal entity that owns or operates a local distribution facility used for the sale of electric energy to an electric consumer.

`(5) There are authorized to be appropriated to the Department of Energy such sums as may be necessary to carry out the purposes of this section.

`(6) The Secretary is authorized to promulgate such regulations as the Secretary determines to be necessary to carry out the provisions of this subsection.

`(c) LOAN GUARANTEE PROGRAM-

`(1) AUTHORITY- The Secretary may guarantee not more than 90 percent of the unpaid principal and interest due on any loan made to any Indian tribe for energy development, including the planning, development, construction, and maintenance of electrical generation plants, and for transmission and delivery mechanisms for electricity produced on Indian land. A loan guaranteed under this subsection shall be made by--

`(A) a financial institution subject to the examination of the Secretary; or

`(B) an Indian tribe, from funds of the Indian tribe, to another Indian tribe.

`(2) AVAILABILITY OF APPROPRIATIONS- Amounts appropriated to cover the cost of loan guarantees shall be available without fiscal year limitation to the Secretary to fulfill obligations arising under this subsection.

`(3) AUTHORIZATION OF APPROPRIATIONS- (A) There are authorized to be appropriated to the Secretary such sums as may be necessary to cover the cost of loan guarantees, as defined by section 502(5) of the Federal Credit Reform Act of 1990 (2 U.S.C. 661a(5)).

`(B) There are authorized to be appropriated to the Secretary such sums as may be necessary to cover the administrative expenses related to carrying out the loan guarantee program established by this subsection.

`(4) LIMITATION ON AMOUNT- The aggregate outstanding amount guaranteed by the Secretary of Energy at any one time under this subsection shall not exceed $2,000,000,000.

`(5) REGULATIONS- The Secretary is authorized to promulgate such regulations as the Secretary determines to be necessary to carry out the provisions of this subsection.

`(d) INDIAN ENERGY PREFERENCE- (1) An agency or department of the United States Government may give, in the purchase of electricity, oil, gas, coal, or other energy product or by-product, preference in such purchase to an energy and resource production enterprise, partnership, corporation, or other type of business organization majority or wholly owned and controlled by a tribal government.

`(2) In implementing this subsection, an agency or department shall pay no more than the prevailing market price for the energy product or by-product and shall obtain no less than existing market terms and conditions.

`(e) EFFECT ON OTHER LAWS- This section does not--

`(1) limit the discretion vested in an Administrator of a Federal power marketing agency to market and allocate Federal power, or

`(2) alter Federal laws under which a Federal power marketing agency markets, allocates, or purchases power.'.

SEC. 402. OFFICE OF INDIAN ENERGY POLICY AND PROGRAMS.

Title II of the Department of Energy Organization Act is amended by adding at the end the following:

`OFFICE OF INDIAN ENERGY POLICY AND PROGRAMS

`SEC. 217. (a) There is established within the Department an Office of Indian Energy Policy and Programs. This Office shall be headed by a Director, who shall be appointed by the Secretary and compensated at the rate equal to that of level IV of the Executive Schedule under section 5315 of title 5, United States Code.

`(b) The Director shall provide, direct, foster, coordinate, and implement energy planning, education, management, conservation, and delivery programs of the Department that--

`(1) promote tribal energy efficiency and utilization;

`(2) modernize and develop, for the benefit of Indian tribes, tribal energy and economic infrastructure related to natural resource development and electrification;

`(3) preserve and promote tribal sovereignty and self determination related to energy matters and energy deregulation;

`(4) lower or stabilize energy costs; and

`(5) electrify tribal members' homes and tribal lands.

`(c) The Director shall carry out the duties assigned the Secretary or the Director under title XXVI of the Energy Policy Act of 1992 (25 U.S.C. 3501 et seq.).'.

SEC. 403. CONFORMING AMENDMENTS.

(a) AUTHORIZATION OF APPROPRIATIONS- Section 2603(c) of the Energy Policy Act of 1992 (25 U.S.C. 3503(c)) is amended to read as follows:

'(c) AUTHORIZATION OF APPROPRIATIONS- There are authorized to be appropriated such sums as may be necessary to carry out the purposes of this section.'.

(b) TABLE OF CONTENTS- The table of contents of the Department of Energy Act is amended by inserting after the item relating to section 216 the following new item:

'Sec. 217. Office of Indian Energy Policy and Programs.'.

(c) EXECUTIVE SCHEDULE- Section 5315 of title 5, United States Code, is amended by inserting 'Director, Office of Indian Energy Policy and Programs, Department of Energy.' after 'Inspector General, Department of Energy.'.

SEC. 404. SITING ENERGY FACILITIES ON TRIBAL LANDS.

(a) DEFINITIONS- For purposes of this section:

(1) INDIAN TRIBE- The term 'Indian tribe' means any Indian tribe, band, nation, or other organized group or community, which is recognized as eligible for the special programs and services provided by the United States to Indians because of their status as Indians, except that such term does not include any Regional Corporation as defined in section 3(g) of the Alaska Native Claims Settlement Act (43 U.S.C. 1602(g)).

(2) INTERESTED PARTY- The term 'interested party' means a person whose interests could be adversely affected by the decision of an Indian tribe to grant a lease or right-of-way pursuant to this section.

(3) PETITION- The term 'petition' means a written request submitted to the Secretary for the review of an action (or inaction) of the Indian tribe that is claimed to be in violation of the approved tribal regulations.

(4) RESERVATION- The term 'reservation' means--

(A) with respect to a reservation in a State other than Oklahoma, all land that has been set aside or that has been acknowledged as having been set aside by the United States for the use of an Indian tribe, the exterior boundaries of which are more particularly defined in a final tribal treaty, agreement, executive order, Federal statute, secretarial order, or judicial determination;

(B) with respect to a reservation in the State of Oklahoma, all land that is--

(i) within the jurisdictional area of an Indian tribe, and

(ii) within the boundaries of the last reservation of such tribe that was established by treaty, executive order, or secretarial order.

(5) SECRETARY- The term 'Secretary' means the Secretary of the Interior.

(6) TRIBAL LANDS- The term 'tribal lands' means any tribal trust lands, or other lands owned by an Indian tribe that are within such tribe's reservation.

(b) LEASES INVOLVING GENERATION, TRANSMISSION, DISTRIBUTION OR ENERGY PROCESSING FACILITIES- An Indian tribe may grant a lease of tribal land for electric generation, transmission, or distribution facilities, or facilities to process or refine renewable or nonrenewable energy resources developed on tribal lands, and such leases shall not require the approval of the Secretary if the lease is executed under tribal regulations approved by the Secretary under this subsection and the term of the lease does not exceed 30 years.

(c) RIGHTS-OF-WAY FOR ELECTRIC GENERATION, TRANSMISSION, DISTRIBUTION OR ENERGY PROCESSING FACILITIES- An Indian tribe may grant a right-of-way over tribal lands for a pipeline or an electric transmission or distribution line without separate approval by the Secretary, if--

(1) the right-of-way is executed under and complies with tribal regulations approved by the Secretary and the term of the right-of-way does not exceed 30 years; and

(2) the pipeline or electric transmission or distribution line serves--

(A) an electric generation, transmission or distribution facility located on tribal land, or

(B) a facility located on tribal land that processes or refines renewable or nonrenewable energy resources developed on tribal lands.

Sent

Seifert, Roger - DC/WASH

From: Seifert, Roger - KN-DC
Sent: Friday, July 26, 2002 12:16 PM
To: 'Kabat, Gale'
Subject: FW: Wyden BPA Borrowing Authority Amendment

FYI, this is the other information I provided Bill today. Bill tells me he did not sent this on to Bruce Carnes, but I thought you ought to have it too. If the conferees do at some point considwer adopting BPA borrowing authority, we should try to make these changes to try and preserve our historic relationship with the Treasury.

-----Original Message-----
From: Seifert, Roger - KN-DC
Sent: Friday, July 26, 2002 11:20 AM
To: 'Palmer, William'
Cc: Stier, Jeffrey K - KN-DC; Curtis, Jim - DF-2; Hawken, Mary - DFF-2; Roach, Randy A - L-7; Majkut, Paul S - LC-7
Subject: Wyden BPA Borrowing Authority Amendment

Attached is an electronic copy of the technical fixes to the Senate Legislative Council drafted Wyden Amendment that we suggested at the time the bill was being considered. As I have indicated several previous times we were trying to keep our Treasury borrowing relationship (to Treasury and not direct to market) as it has historically been. As I have also indicated previously, I have also had several conversations with Paula Farrell to assure her we wanted to do that, but were not successful. Since you asked for the Senate passed Wyden Amendment, Jeff and I wanted you to have these needed changes to avoid changing our relationship with Treasury and how our borrowing interest rates are determined.

Borrowing Authority Increase.d...

SA 3230. Mr. WYDEN submitted an amendment intended to be proposed to amendment SA 2917 proposed by Mr. DASCHLE (for himself and Mr. BINGAMAN) to the bill (S. 517) to authorize funding the Department of Energy to enhance its mission areas through technology transfer and partnerships for fiscal years 2002 through 2006, and for other purposes; which was ordered to lie on the table; as follows:

On page 62, between lines 3 and 4, insert the following:

SEC. 2__. BONNEVILLE POWER ADMINISTRATION BONDS.

Section 13 of the Federal Columbia River Transmission System Act (16 U.S.C. 838k) is amended--

(1) by striking the section heading and all that follows through ``(a) The Administrator" and inserting the following:

``SEC. 13. BONNEVILLE POWER ADMINISTRATION BONDS.

``(a) **BONDS.**--

``(1) **IN GENERAL.**--The Administrator"; and

(2) by adding at the end the following:

``(2) **ADDITIONAL BORROWING AUTHORITY.**--In addition to the borrowing authority of the Administrator authorized under paragraph (1) or any other provision of law, an additional $1,300,000,000 is made available, as provided in this section, to remain outstanding at any ~~1~~ one time--

``(A) to provide funds to assist in financing the construction, acquisition, and replacement of the transmission system of the Bonneville Power Administration; and

``(B) to implement the authorities of the Administrator under the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839 et seq.).".

Stier, Jeffrey K - DC/WASH

From: Richard Kogan [kogan@cbpp.org]
Sent: Tuesday, June 25, 2002 3:05 PM
To: Stier, Jeffrey K - KN-DC
Subject: RE: A question not related to your present work

All of your recap is accurate. OMB and I tend to call the borrowing limit a "limit on outstanding debt." We do this in part to avoid confusion with the term "borrowing authority," which is (and is scored as) a type of budget authority (BA). Thus, as you say, an increase in the limit on outstanding debt will be scored as an increase in BA only to the extent it is estimated to be used, either in the budget year or the future.

I take it that the authorizing committees are willing to increase the BPA's limit on outstanding debt, that CBO will score some BA and outlays increases as flowing from that increase, and that the House and Senate budget resolutions would allocate to the authorizing committees enough to cover the BA and outlay increases.

As you are no doubt aware, Congress has not reached agreement on a budget resolution and will not. On May 22, the House passed a simple resolution "deeming" Congress to have agreed to a budget resolution (the one the House had previously passed) for purposes of its own rules. Thus, the House authorizing committee now has officially received its allocation and can proceed on the increase in the limit on BPA's outstanding debt.

The Senate cannot go even this far -- the votes are too close and there is no majority for any budget plan. Therefore, the Senate authorizing committee does not have a new allocation, and so is legally working on the basis of last year's budget resolution and its attendant allocation -- which has no room remaining in it for increases for BPA or anyone else. As a result, an increase in the limit on BPA's outstanding debt will violate Senate rules, which are (however) waiveable by the vote of 60 Senators.

If, on the other hand, the increase were contained in an appropriations bill (aha -- I did not forget), the relevant allocation would be the allocation for the Appropriations Committee, not the authorizing committee. Here, the Appropriations Committee could simply decide to incorporate the 2003 BA and outlay costs of the BPA increase within its overall allocation. furthermore, in the absence of a new budget resolution in the Senate, the Appropriations Committee does not revert to a prior budget resolution (unlike authorizing committees); rather, the Appropriations bills are not supposed to move at all. This prohibition can be waived by majority vote, and if it is waived, there is no Senate procedural limit on the costs that can be included in the Appropriations bills.

You might think that Senate Appropriations would like to proceed unfettered, but you would be wrong -- Senate Appropriations desires an overall limit or allocation, but wants one somewhat above the President's level. Appropriations wants a reasonable limit because the existence of a limit protects it in a number of ways -- from irresponsible name-calling and from excessive floor amendments, for example. It is plausible to think that, through some arrangement, the Senate Appropriations Committee will be "deemed" to have an allocation/limit for 2003, much as the House is deemed to have an entire budget resolution. Until then, however, Senate Appropriations is stalled.

Suppose all this is resolved, however. At that point, both House and Senate Appropriations will be able to incorporate the BPA increase in outstanding debt into their Appropriations bills (though such language violates the generic rule against "authorizing in an appropriations bill"). If CBO estimates 2003 costs, Appropriations will have to fit those costs into their allocations, which could be especially tricky in the House since it is likely to have a lower total allocation than the Senate.

What of the outyear costs associated with the BPA increase? Under current law, this is a procedural non-issue. As you correctly point out, by next year those costs will be rebased as mandatory and incorporated into the current law baseline.

Where did the notion arise that Appropriations would have to eat the outyear costs in subsequent years? The answer is that the old system of multiyear caps produced that result. Back when year-by-year statutory caps applied to appropriations (and were enforced), the way in which Appropriations was held responsible for language that would produce outyear mandatory costs (such as the proposed increase in BPA's limit on outstanding debt) was for OMB to automatically reduce the outyear appropriations caps by the amount of the estimated outyear costs of the language. Thus, the person who suggested there could be a problem was remember a former reality. But a) the caps have not been enforced for four years, and b) the caps expire at the end of 2002, so there are no 2004, 2005, ... caps that OMB could reduce. Therefore, under current law, no one will be held accountable for (have to pay for) the outyear costs of an Appropriations increase in the BPA limit on outstanding debt.

One might write editorials about this, but I wouldn't bother.

-----Original Message-----
From: Stier, Jeffrey K - KN-DC [mailto:jkstier@bpa.gov]
Sent: Tuesday, June 25, 2002 1:39 PM
To: 'kogan@cbpp.org'
Subject: A question not related to your present work

You may recall a phone call last year from Rep. Norm Dicks regarding the treatment under the Budget Act of an increase in the cap on the permanent borrowing authority of the Bonneville Power Administration (BPA). I'm writing to be sure that I understand the explanation you gave us over the phone that day.

As you may recall (or know), BPA is a self-financed agency with authority to sell bonds to Treasury to raise capital for certain purposes. It's a revolving account; our total limit on borrowing is $3.75 billion. We are seeking an increase in our borrowing limit. The President has requested a $700 million increase. The Senate adopted an amendment to the Energy bill to increase the limit by $1.3 billion. To complete the picture - an increase of $700 million is assumed in the House-passed budget resolution; the Senate Budget Committee's resolution assumes a $1.3 billion increase, though I do not know in either case where or how this is presented.

You explained to us that, for scoring purposes, an increase in our borrowing limit would be counted as an increase in discretionary spending in the year in which it became effective - to the extent there was an associated increase in spending in that year. Once enacted into law, the outyear increases are "rebased" as mandatory spending.

The question that has come up is this: despite being included in the Senate's energy bill, members of our congressional delegation are trying to convince the Appropriations Committees to include this in their FY03 spending bills. At least one Committee staffer believes that including this increase in the Committee's bill would have the consequence of reducing the Committee's discretionary spending allocations in the outyears by an amount equal to the corresponding increase in spending (our draft legislative language places a limit on our use of borrowing authority in FY03 that CBO has determined will result in no additional ba or outlays in FY03).

Is there any legal or technical (as opposed to political) reason that increasing mandatory spending in the outyears in an Appropriations bill would reduce the Appropriations Committee's discretionary spending allocation in the outyears?

I'm sure you're busy at this time of year, but we would appreciate your advice in this. Thanks.

Jeff Stier
VP for National Relations
Bonneville Power Administration
202-586-5640

Stier, Jeffrey K - DC/WASH

From: garybarbour [garybarbour@msn.com]
Sent: Tuesday, October 01, 2002 2:48 PM
To: Vinson, Tom
Cc: Jeff Stier; Scott Corwin
Subject: RE: here it is

What I hear is this offer was thrown out by Tauzin and may not have much support within his own membership. For example, he includes an RPS program with a very slow ramp up, but continues to exempt publics and coops; which is why his R's are going balistic. (Enetergy apparently supports RPS.) The PUHCA stuff is messed up, so I am told. Bingaman's folks are worried that it is so different than other PUHCA stuff they've looked at it will take to long to get thru it. The FERC lite language, (circa pp. 2-6) appears to exempt everyone under 4 mil. mwh but still defines them as potentially w/i FERC jurisdiction, nor does it address BPA. BPA does get $1.3 B in borrowing authority pp.75. Now I hear that Daschle has convened a meeting for 6:30 this eve. to get a read on the conference and likely make a decision on what to do with his favorite program, ethanol.

> -----Original Message-----
> **From:** Vinson, Tom [mailto:Tom.Vinson@mail.house.gov]
> **Sent:** Tuesday, October 01, 2002 2:04 PM
> **To:** 'garybarbour@msn.com'
> **Subject:** RE: here it is
>
> i don't know what's going on with the senate. i have no idea if something is going to be offered this afternoon or not.
>
> > -----Original Message-----
> > **From:** garybarbour [mailto:garybarbour@msn.com]
> > **Sent:** Tuesday, October 01, 2002 1:57 PM
> > **To:** Vinson, Tom
> > **Subject:** RE: here it is
> >
> > What happened to Binaman's counter offer? I've been talking with Craig and Thomas's offices...
> >
> > > -----Original Message-----
> > > **From:** Vinson, Tom [mailto:Tom.Vinson@mail.house.gov]
> > > **Sent:** Tuesday, October 01, 2002 1:35 PM
> > > **To:** 'jkstier@bpa.gov'; 'rich.glick@pacificorp.com'; 'mkanner@kannerandassoc.com'; 'nmorgado@kannerandassoc.com'; 'garybarbour@msn.com'; 'dsliz@morganmeguire.com'; 'kprice@morganmeguire.com'
> > > **Cc:** Flachbart, Amy; Griffin, Paul; 'doug_clapp@murray.senate.gov'; 'george_o'connor@craig.senate.gov'
> > > **Subject:** FW: here it is
> > >
> > > FYI...attached is what I'm told is the latest draft House offer on electricity...
> > >
> > > Tom

Stier, Jeffrey K - DC/WASH

From: Scott Althouse [scotta@enterprise.nezperce.org]
Sent: Wednesday, September 18, 2002 6:32 PM
To: jkstier@bpa.gov; racohen@bpa.gov
Subject: Thank you

Jeff & Ashley,

Thank you for taking time to meet with tribal leaders last Wednesday. I think the meeting went a long way towards diffusing some of the tension that has built up between BPA and CRITFC. I enjoyed our discussion of the Fish & Wildlife Program as it relates to the pending decisions on financial choices and increased borrowing authority. Please stay in touch and let me know how the Nez Perce Tribe can be of further assistance on these or future issues.

Sincerely,

Scott Althouse

--
H. Scott Althouse

Nez Perce Tribe
Watershed Division -
Department of Fisheries Resources Management

Office: 208-843-3015 P.O. Box 365
Fax: 208-843-9192 Lapwai, ID 83540
Mobile: 503-358-6462
scotta@nezperce.org
--

Stier, Jeffrey K - DC/WASH

From: Nicole Cordan [nicole@wildsalmon.org]
Sent: Tuesday, September 10, 2002 3:40 PM
To: jkstier@bpa.gov
Subject: BPA Borrowing Authority

Jeff-

As we discussed, here's the most recent SOS coalition letter on BPA borrowing authority. I hope it better clarifies our position and concerns. It will be delivered to offices on the Hill by tomorrow.

As always, feel free to contact me or Andrew Englander of my staff (or of course, any of the undersigned organizations) if you have questions about this letter.

Take care,
Nicole

****

American Rivers * Idaho Rivers United * Pacific Coast Federation of Fishermen's Associations * National Wildlife Federation *

Save Our *Wild* Salmon * Sierra Club * Trout Unlimited

September 10, 2002

Re: Section 272 of H.R. 4 (Energy Policy Act of 2002, Engrossed Senate Amendment), to Increase Borrowing Authority for Bonneville Power Administration

Dear Energy Bill Conferee:

Our organizations are writing to express our concerns regarding Section 272 in the Senatepassed Energy Policy Act of 2002 (H.R. 4, Engrossed Senate Amendment) currently being considered by the Conference Committee. This section would provide the Bonneville Power Administration (BPA) an additional $1.3 billion in new borrowing authority from the federal Treasury. We believe that as currently crafted, this provision fails to ensure the proper protections for salmon affected by the Federal Columbia River Power System (FCRPS). Similarly, the proposal fails to ensure that BPA will prioritize the use of new capital on its public purpose responsibilites such as energy conservation and renewable energy investments. In light of BPA's recent record on salmon recovery, we feel that Section 272 should not be approved without an adequate assurance that BPA will meet its legal responsibility to protect salmon. Therefore we urge you to either substantially modify or delete Section 272 at this time.

Currently, BPA is authorized by the Federal Columbia River Transmission System Act to borrow from the U.S. Treasury up to $3.75 billion to finance its capital programs. By law, one third of that total ($1.25 billion) is reserved for conservation and renewable resource grants and loans. In its fiscal year 2003 budget request, the Bush Administration requested an increase in borrowing authority of $700 million, with the condition that BPA also pursue joint or private funding and not use the additional capital until FY 2004.

We are concerned that Section 272 is a dramatic departure from both current law and the Administration request, and it has not been subject to adequate Congressional or public review. Short of deleting the section from the bill, we request the Energy Bill Conferees to amend Section 272 to limit and condition the increased borrowing authority for BPA as follows:

1/3 of new borrowing authority should be reserved for conservation and renewable resources. As noted above, 33 percent of BPA's current borrowing authority is reserved for conservation resource loans and grants. Such programs play a vital role in reducing the energy burden on the Columbia and Snake rivers while ensuring a reliable power system and aiding the recovery of salmon. Any new borrowing authority should continue to explicitly reserve that same percentage of new funding for projects and programs to acquire or promote energy conservation and renewable resources.

Decrease new borrowing authority to the Administration's request. Current infrastructure needs are not sufficiently urgent to necessitate an increase of BPA's borrowing authority nearly double what the Bush Administration requested. Section 272 would raise BPA's borrowing authority by 35 percent over its current $3.75 billion authority. At most, the Conferees should approve the more reasonable sum of $700 million found in the administration's FY03 budget request.

In addition to the above changes to Section 272, we request that the Conferees also include report language to ensure BPA uses any increased borrowing authority appropriately. For instance, the 2001 juvenile salmon migration was marred by the poorest in-river survival estimates since salmon were listed for protection under the Endangered Species Act due in part to BPA's refusal to abide by the river operation requirements set forth in the 2000 Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp). These programs were curtailed, and in some instances suspended, subject to the guidelines of "emergency criteria" which specifically call on BPA to evaluate the adequacy of financial reserves, among other things, before implementing salmon recovery measures.

In light of BPA's dismal performance in meeting its fish and wildlife obligations, we request that the Conferees add report language calling for detailed oversight or an investigation of BPA's record on meeting the salmon recovery goals of the Northwest Power Act, the Endangered Species Act, and tribal treaties. A recent report by the Government Accounting Office (GAO) found that despite $3.3 billion in taxpayer and ratepayer money spent in the last 20 years on Northwest salmon recovery efforts, there is little evidence to indicate that current recovery measures are succeeding. The GAO report heightens the need for Congressional oversight about BPA's salmon recovery actions.

We recognize that most of BPA's current expenditures on salmon habitat restoration are not financed through the agency's existing borrowing authority. However, given BPA's recent lack of commitment to its salmon recovery responsibilities, we urge the Conferees to direct BPA to use its borrowing authority on general salmon recovery measures, if deemed necessary for the agency to meet its legal requirements.

We also recognize that there are a number of transmission projects financed through borrowing authority that may provide more flexibility in meeting salmon restoration requirements. We specifically request that the Conferees include report language directing BPA to prioritize such projects. There are currently 20 priority transmission projects that BPA plans to build with additional borrowing. Among those, at least two projects appear to be transmission improvements required by the FCRPS BiOp and could assist in power management such that during an emergency fish are not sacrificed. Those two projects are:

A) **Schultz-Hanford 500kV line** -- implementation by 2004 or 2005. This project would make additional daytime spill possible at dams on the lower Columbia River; and

B) **West-of-Hatwai Cutplane** A joint transmission project to upgrade the west-of-Hatwai cutplane to improve transfer from Montana. This project would make additional daytime spill at the Snake River dams possible.

Thank you for your consideration. Please contact us if you would like to discuss our concerns in more detail.

Sincerely,

Pat Ford, Executive Director, Save Our *Wild* Salmon
Bill Arthur, Northwest Regional Director, Sierra Club
Glen Spain, Northwest Regional Director, Pacific Coast Federation of Fishermen's Associations
Bill Sedivy, Executive Director, Idaho Rivers United
Jeff Curtis, Western Conservation Director, Trout Unlimited
Paula Del Giudice, Regional Director, National Wildlife Federation
Rob Masonis, Northwest Regional Director, American Rivers

Stier, Jeffrey K - DC/WASH

From: Cohen, Ashley - KN-DC
Sent: Tuesday, September 10, 2002 11:52 AM
To: Darr, George D - PT-5; Malin, Debra - PT-5; Bennett, Barry - LT-7; Roach, Randy A - L-7
Cc: Wright, Stephen J - A-7; Stier, Jeffrey K - KN-DC
Subject: Renewable Portfolio Standard

i just talked with ted case with NRECA. he indicated that there is a strong possibility of co-ops, munis, and publics losing their renewable portfolio standard (RPS) exemption. as you recall, BPA is exempt as an agency of the united states. i'm not sure if our exemption is in jeopardy. but, ted is trying to get an idea of what it will mean financially for their NRECA members in the NW if they lose their RPS exemption. conferees are having a hard time justifying exempting the city of LA as a public entity while holding the smallest of the small IOUs to the standard. **i know we did a little bit of work on this before, but with the latest iteration of the RPS language, is their anyway we can predict how the standard will apply to our preference customers?** here's the language:

Ashley

SEC. 264. RENEWABLE PORTFOLIO STANDARD.

Title VI of the Public Utility Regulatory Policies Act of 1978 is amended by adding at the end the following:

'SEC. 606. FEDERAL RENEWABLE PORTFOLIO STANDARD.

Stier, Jeffrey K - DC/WASH

From: Seifert, Roger - KN-DC
Sent: Friday, July 26, 2002 11:25 AM
To: 'Palmer, William'
Subject: FW: Wyden BPA Borrowing Authority Amendment

Importance: High

Wyden Borrowing Amendment.htm

Per your fast request Bill, her is a copy of the Senate passed Wyden BPA borrowing authority amendment. This amendment was to H.R. 4 with the engrossed amendments of the Senate.

Stier, Jeffrey K - DC/WASH

From: Seifert, Roger - KN-DC
Sent: Friday, July 26, 2002 11:02 AM
To: 'Palmieri, Tom'
Cc: Stier, Jeffrey K - KN-DC; Wright, Stephen J - A-7
Subject: Wyden BPA Borrowing Authority Amendment

Importance: High

Wyden Borrowing Amendment.htm

Per your fast request Bill, her is a copy of the Senate passed Wyden BPA borrowing authority amendment. This amendment was to H.R. 4 with the engrossed amendments of the Senate.

Cohen, Ashley - DC/WASH

From: Vinson, Tom [Tom.Vinson@mail.house.gov]
Sent: Friday, July 19, 2002 11:20 AM
To: 'jkstier@bpa.gov'; 'racohen@bpa.gov'; 'caball@bpa.gov'
Subject: borrowing authority

i just returned from day 2 of the energy conference discussion of senate electricity provisions. the last thing discussed was borrowing authority. there was mostly token concern from markey and waxman's staff. waxman's staff specifically expressed concern that none of the $1.3 billion was specifically targeted for conservation and fish. the language mentions these, but it would be up to BPA how to allocate the money. barton's staff asked whether the administration supported it. i noted it was in the president's budget. they asked how much? george o'connor admitted it was $700 million.

we need to think about how to deflect the waxman criticism. does BPA have $1.3 billion in necessary transmission projects that we can point to (i seem to recall you only had $700 million in transmission projects that could be listed on paper)? are there any transmission projects that are being done for fish? is BPA willing to settle for the lower figure if there is no earmark for fish/conservation?

Tom Vinson
Legislative Director
Representative Peter DeFazio (OR-04)
2134 Rayburn House Office Building
WDC 20515
ph: 202-225-6416
fx: 202-225-0032

Cohen, Ashley - DC/WASH

From: Cohen, Ashley - KN-DC
Sent: Wednesday, September 04, 2002 9:16 AM
To: Seifert, Roger - KN-DC
Subject: FW: borrowing authority

puget sound energy's congressional affiars representative is interested in getting a simple breakdwon of how we would use the borrowing authority under both the $700 million and the $1.3 billion cenerios. he's just looking for a percentage breakdown of how much will go towards transmission upgrades, how much will go towards improvements on the hydro system, and how much will go to conservation and renewables.

clearly, puget is very supportive our increased borrowing authority, they just would like some more information. thanks.

ashley

-----Original Message-----
From: Einstein, William [mailto:will.einstein@pse.com]
Sent: Tuesday, September 03, 2002 8:54 PM
To: Ashley Cohen
Subject: borrowing authority

Thanks for a fun lunch today.

Can you send me the borrowing authority explanation. I would like to get some of the information to folks in our company.

Talk to you soon.

Cohen, Ashley - DC/WASH

From: Cohen, Ashley - KN-DC
Sent: Wednesday, September 04, 2002 3:41 PM
To: 'Einstein, William'
Subject: RE: borrowing authority

will -- here's your information. call me if you have any questions. It should be noted that these are rough estimates subject to change. talk to you later.

ashley

Bonneville Power Administration Capital Investment Summary ($ millions)
(these rough estimates are based on BPA receiving an additional $700 million in borrowing authority)

	FY04	FY05	FY06
Power	$18	$91	$21
Conservation	$9	$53	$14
Fish	$6	$24	$5
Transmission	$76	$310	$47
Capital Equipment	$4	$18	$2
Capitalized Bond Premium	$0	$2	$0
Total	$113	$498	$89

-----Original Message-----
From: Einstein, William [mailto:will.einstein@pse.com]
Sent: Tuesday, September 03, 2002 8:54 PM
To: Ashley Cohen
Subject: borrowing authority

Thanks for a fun lunch today.

Can you send me the borrowing authority explanation. I would like to get some of the information to folks in our company.

Talk to you soon.

Cohen, Ashley - DC/WASH

To: scotta@enterprise.nezperce.org
Subject: RE: Thank you

-----Original Message-----
From: Scott Althouse [mailto:scotta@enterprise.nezperce.org]
Sent: Wednesday, September 18, 2002 6:32 PM
To: jkstier@bpa.gov; racohen@bpa.gov
Subject: Thank you

Jeff & Ashley,

Thank you for taking time to meet with tribal leaders last Wednesday. I think the meeting went a long way towards diffusing some of the tension that has built up between BPA and CRITFC. I enjoyed our discussion of the Fish & Wildlife Program as it relates to the pending decisions on financial choices and increased borrowing authority. Please stay in touch and let me know how the Nez Perce Tribe can be of further assistance on these or future issues.

Sincerely,

Scott Althouse

--
H. Scott Althouse

Nez Perce Tribe
Watershed Division -
Department of Fisheries Resources Management

Office: 208-843-3015 P.O. Box 365
Fax: 208-843-9192 Lapwai, ID 83540
Mobile: 503-358-6462
scotta@nezperce.org
--

company owner Ed Taft.

€ The Intelligent Community Forum has named LaGrange, Ga., one of the top seven intelligent communities of the year, calling the rural city a pioneer in developing private ventures for broadband-based economic development. LaGrange is the only American city branded with the global distinction.
Don't we know some PUD communities that might qualify for this award?

€ A page-one Seattle Times article reported today that Washington officials are concerned that global warming will diminish the state's annual snow pack, affecting fish populations, hydro generation, and more. The story says officials are having trouble getting resource managers to confront the problem. You can confront it at http://seattletimes.nwsource.com/html/localnews/134500686_climatechange26m.html

SourceBook data for the year 2001 is due! Please submit completed forms to the PUD Association!

--
FridayFax is produced by staff and consultants to the Washington PUD Association. Olympia reports: Stu Trefry, Bill Stauffacher, Steve Duncan; Water reports: John Kounts; Washington, D.C. reports: Morgan Meguire staff. Editor: Sarah Driggs, 206-467-1327, sdriggs@wpuda.org

FridayFax is intended for the use of Washington PUD Association members. Please check with us before distributing FridayFax to others.

Ball, Crystal A - DC/WASH

From: Columbia Basin Bulletin [cbb@topica.email-publisher.com]
Sent: Friday, July 26, 2002 5:16 PM
To: caball@bpa.gov
Subject: CBB, 7/26, Part 1 of 2

EDITOR'S NOTE: If the Columbia Basin Bulletin has been forwarded to you, please SUBSCRIBE by visiting our website at HTTP://WWW.CBBULLETIN.COM AND CLICKING ON THE SUBSCRIBE BUTTON, or by sending an e-mail to intercom@ucinet.com. Put Subscribe CBB in the subject line.

-- Bill Crampton, editor, intercom@ucinet.com , phone: 541-312-8862;
fax: 541-312-2806

THE COLUMBIA BASIN BULLETIN:
Weekly Fish and Wildlife News
July 26, 2002

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1. NMFS' DRAFT HATCHERY POLICY FOCUSES ON WILD FISH PROTECTION

By Barry Espenson

The National Marine Fisheries Service on Wednesday released a preliminary draft hatchery policy that reaffirms the agency's emphasis on building self-sustaining salmon and steelhead populations in their natural ecosystem with careful consideration of the risks and benefits that hatchery fish might bring to the recovery process.

The working draft shipped off to NMFS' federal, state and tribal fish co-managers this week is a completed first step in development of a new policy to guide NMFS' consideration of hatchery fish in making determinations on Endangered Species Act listings.

Co-managers say they want to study the document carefully before commenting on the its merits. NMFS has asked them to provide technical and policy comments by Aug. 16. The document would then be reworked and released for an official public comment period.

Two legal adversaries involved in the lawsuit that triggered the policy review again offered contrary views. Those that believe the hatchery fish are, essentially, the equals of wild, naturally produced fish say that the policy put forth in the draft will only stimulate more litigation. Those that want recovery focused on wild fish alone say the draft is a step in the right direction.

The reworking of NMFS' artificial production policy, and a reconsideration of 24 of 26 West Coast salmon and steelhead listing decisions, was forced with last year's U.S. District Court decision in Alsea Valley Alliance v. Evans. Judge Michael Hogan found that NMFS' 1998 listing of Oregon Coast coho made improper distinctions beyond the level of an "evolutionarily significant unit" by excluding hatchery populations from listing protection even though they were determined to be part of the same ESU as listed naturally spawning populations. As a result the coho were dropped from the ESA list.

A U.S. Court of Appeals for the Ninth Circuit subsequently granted an emergency motion filed by conservation groups to stay the judgment while the listing decision was reconsidered, effectively restoring ESA protections.

"This new policy is intended to ensure, in accordance with the Court's ruling, that hatchery populations are considered in determining whether or not to list an ESU under the ESA," NMFS regional administrator D. Robert Lohn said in a cover letter to co-managers. "The policy will more clearly articulate how the agency will consider artificial propagation in conducting ESA status reviews and listing determinations for Pacific salmon and steelhead."

Lohn's letter to co-managers stressed four points in the "working draft:"
-- The natural and hatchery populations that comprise an ESU would be determined prior to the status assessment for the ESU. In past status reviews NOAA Fisheries first identified the natural populations comprising an ESU, then determined the status of these populations, and subsequently considered which hatchery populations were also part of the ESU.
-- Assessments of extinction risk, or the risk of endangerment, would be based on the likelihood that an ESU as a whole is sustaining itself through natural reproduction in its natural ecosystem over the long term.
-- Both the positive and negative effects of artificial propagation will be considered in the ESA status reviews and listing determinations. This consideration will be given in the context of whether artificial propagation represents a protective effort that provides a genetic reserve for the ESU, contributes to long-term self-sustainability of the ESU in the natural ecosystem, or reduces threats to the ESU through the reform of harmful hatchery practices.
-- If an ESU as a whole warrants listing, all populations in an ESU will be listed whether they are of natural or hatchery origin, as prescribes by the Alsea decision.

"Consistent with the ESU policy, to be considered part of the ESU a hatchery population must be representative of the evolutionary lineage of the ESU, and it must not have diverged appreciably from the parent population in measurable biological characteristics," the draft policy says. Appreciable divergence, or uncertain lineage, would preclude a hatchery stock from inclusion in the ESU.

The draft policy say that a tack with the potential to give both natural and hatchery-produced populations ESA-listed status presents challenges.

"While this proposed policy requires NMFS to list all populations within a threatened or endangered ESU, the ESA does not require NMFS to implement protective regulations equally among populations within an ESU," according to the working draft. The ESA requires that protections be "applied appropriately for all listed populations. This does not mean, however, that these protections will apply to hatchery populations exactly as they will to natural populations."

"The presumption should not be that there are equal protection" across the board, said Garth Griffin, a NMFS supervisory fishery biologist. He said that the ESA gives NMFS descretion about what level of protection to provide various components of a listed stock. The agency would likely have to make those decisions on a case-by-case basis, he said.

The Sept. 12 ruling prompted a flood of actions. In September and October the agency received six petitions asking that 15 of the 26 listed Pacific salmon and steelhead ESUs be delisted. All of the delisting petitions cited the Hogan decision. A petition filed in April of this year asked that only the "wild, naturally producing" fish among 15 West Coast salmon and steelhead stocks should be listed. (See Story No. 4 below)

NMFS announced in November 2001 that it would begin work to revise its hatchery policy and launch status reviews of all ESUs that include hatchery elements.

In early February the NMFS announced, in response to the delisting petitions, that "review may be warranted for 14 of the 15 petitioned ESUs." That established a deadline -- the ESA says the agency is to produce a "finding" as to whether the stocks should be listed or not within a year from the date the petitions were received. NMFS also announced in February that it would conduct reviews for an additional 11 ESUs containing hatchery fish. In all, 24 of the 26 listed salmon and steelhead ESUs, as well as the Lower Columbia River/southwestern Washington coho ESU, are now under review.

The listing decisions will be made consistent with the new artificial propagation policy, according to NMFS.

Pacific Legal Foundation attorney Russell C. Brooks this week panned NMFS' first hatchery policy draft. Brooks, who represented the Alsea Valley Alliance in the coastal coho case, said that NMFS was "given the opportunity to correct an ESA violation and the service is letting it slip back."

"I don't think anything has changed," said Brooks, who insists relatively abundant hatchery stocks are the genetic equals of the wild fish and should be considered when NMFS is making a final listing determination.

"They are evaluating oranges and listing apples," Brooks said. He said that the document must be changed drastically before a final policy is adopted, or the federal government could expect more litigation.

Earthjustice attorney Patti Goldman said she agreed with the draft policy's statement that listing's should be judged on a wild stocks' ability to sustain themselves in their natural ecosystems. A main difference in the draft from current policy is that more hatchery stocks would be listed, but they would not necessarily receive the same level of ESA protections as the naturally produced stocks. Earthjustice represented intervenors in the Alsea case that pressed and won the stay of the Hogan decision.

Columbia River Inter-Tribal Fish Commission senior policy analyst Doug Dompier said his agency and its member tribes would most certainly offer their thoughts on the NMFS draft. CRITFC's lower Columbia River treaty tribes have long sought more "flexibility" in NMFS policy on the use of artificial propagation -- and supplementation, in particular, in attempts to boost populations.

"It's good to see that it is on the street and will get the review we feel is necessary," Dompier said. The tribes feel that "hatcheries should be used to assist the natural runs."

The information posted on NMFS regional web site stresses that the "working draft," and eventual final policy will address artificial propagation "only in the context of ESA status reviews and listing determinations for Pacific salmon and steelhead. NOAA Fisheries will separately issue guidelines for the design and implementation of artificial propagation programs for the purpose of supporting tribal treaty fisheries, recreational and commercial fisheries, species reintroduction and restoration efforts, and species conservation efforts."

NMFS is asking co-managers to review the draft document and lend their technical and policy expertise on fish and wildlife management issues.

The draft policy is being distributed to co-managers only. The NMFS will consider only their comments during this early policy-building process. Following co-manager review and revision of this working draft, the policy will be formally proposed and go though a crucial public review process, including further opportunity for tribal, state, and federal co-manager input.

NMFS spokesman Brian Gorman said the schedule for that public comment process has not been set.

The mailing list included more than 50 tribal entities, the states of Alaska, California, Idaho, Montana, Oregon and Washington and the U.S. Department of Justice and Fish and Wildlife Service. The co-managers were asked to provide comments by Aug. 16.

Link information:
NMFS: http://www.nwr.noaa.gov/

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2. TANGLE NET FISHERY ANGERS, CONCERNS SPORT ANGLERS

By Barry Espenson

A surprisingly high "bycatch" of steelhead this past spring during Columbia River mainstem commercial fisheries targeting spring chinook salmon has sport anglers concerned, and angered.

The Oregon and Washington departments of fish and wildlife invited sport fishers, guides, sport fishing industry officials and fish conservation groups to comment on this year's "tangle net" demonstration and test fisheries. The assembled group, which included no commercial fishing interests, was also asked how the commercial fisheries could be changed or improved for 2003.

The state fish management agencies' demonstration fishery -- which involved nearly 200 commercial boats at its peak -- was intended to target, first of all, surplus Willamette spring chinook hatchery fish, and secondly, marked upriver spring chinook . The upriver run this year was more than 394,900 adult fish -- the second largest run since counts began in 1938.

Commercial fishers were required to use shorter nets or "drifts" and nets of smaller mesh size than have traditionally been used to catch the large chinook. The larger mesh allowed the chinook to slip part way through -- snaring them around the gills and suffocating them. The smaller mesh was intended entangle the chinook rather than allow them to push their heads through, and allow the fishers to release unmarked, potentially wild fish.

Upper Columbia, Snake River and Willamette spring chinook stocks are listed under the Endangered Species Act. The more chinook-friendly, selective fisheries were expected to allow commercial fishers to catch and keep more of the abundant hatchery spring chinook while minimizing impacts on listed fish. The commercial fleet was also required to check their nets more often and to have on board oxygenated "recovery boxes" with circulating water to help revive lethargic fish before their release back into the water.

And despite the fact that catch rates seem to drop with the smaller mesh sizes, the fleet still fared well. Various mesh size nets were evaluated during a test fishery that followed the late February to late March demonstration full-fleet fishery.

The fleet "handled" a total of 29,400 spring chinook and released 17,700 unmarked fish back into the river. But the commercial boats also caught an unexpectedly high number of steehead -- a species that also has ESA listed components and is designated exclusively as a sport fish. The commercial fishers had to release all 22,100 steelhead caught in their nets.

Vexing the sport fishing interest is the potential physical harm, and mortality, caused to the steelhead by the nets. They believe that the 5 1/2-inch mesh nets used predominantly in the fishery effectively serve as "gill nets" for the steelhead -- which are much smaller than the spring chinook.

A still incomplete evaluation of steelhead mortality from the commercial fishery indicates that "our impacts to the wild fish will be greater than our 2 percent planned preseason," said Cindy LeFleur of the WDFW. The states are operating sport and commercial under an agreement reached with lower Columbia River treaty tribes that allocates the harvest, and allowed impacts on ESA listed fish. One of the sport fishers concerns is that steelhead impacts in the commercial fishery would violate the agreed-upon limits, thus forcing a closure of all non-tribal fisheries. That could have happened this past spring had state officials had the ability to gauge mortality in-season.

"It's very important that steelhead are not caught, and killed," in the demonstration fishery, Phil Leshowitz, Washington state chairman of the Recreational Fishing Alliance.

ODFW salmon fisheries manager Steve King said that the 5 1/2-inch nets used in February and March effectively "did function as a gill net for steelhead," though the nets did not cause the high rates of immediate mortality associated with traditional gill net fisheries. Data collected by the two state agencies shows immediate morality rates of 0.7 percent for chinook and 2 percent for steelhead in the fishery. Estimates of short and long-term mortality of the released fish are not yet available.

Liz Hamilton told agency officials that "hanging 5 1/2-inch coho nets and calling it a tangle net" has caused confusion. The Northwest Sportfishing Industry Association executive director said the states need to more strictly define what they mean by tangle net.

She later urged the states, in 2003, to limit the tangle net fishery to mesh sizes of 4 1/2 inches, at the greatest. She and others attending the meeting said that their preference would be to outlaw the use of nets and concentrate any selective commercial fishing effort on more benign methods, such as fish wheels.

"This full fleet, 5 1/2-inch net stuff just didn't work. It's an embarrassment to everyone," Hamilton said.

"I'm not against commercial fishing. I'm against killing the last wild fish," said Gary

Loomis, president of Fish First. He said it is vital that commercial fishing practices be changed to reduce that bycatch.

"It we don't save the wild fish, where are we going to go to get the eggs the next time the hatcheries have a problem," Loomis added.

WDFW's statewide salmon manager, Tim Flint, acknowledged that the commercial fisheries' steelhead encounter and mortality rates are "unacceptable. He said the 5 1/2-inch mesh nets would not likely be allowed in 2003 in what would be the second planned trial for both the full fleet demonstration fishery and test fishery.

Oregon Trout's Jim Myron told the state officials that they should do a cost-benefit analysis to determine if the economic benefit produced by the spring chinook tangle net fishery was worth it. The associated research was funded in 2002 by the Bonneville Power Administration at $659,000. The effort also requires considerable staff time both for the fish agencies and law enforcement agencies, he said.

He said the states should consider the "option of not doing it at all."

State officials said they intend to continue discussions with both sport and commercial fishing interests on how to shape a 2003 demonstration fishery. Among the goals are to:
-- provide commercial fishers with the opportunity to harvest allocation of surplus Willamette hatchery spring chinook,
-- manage fisheries to remain within ESA-related impact limits for listed upriver and Willamette River wild spring chinook,
-- reduce the handle and mortality of wild steelhead,
-- improve the condition at capture of steelhead, and
-- maintain adequate spring chinook catch rates to limit the total fishing time.

A decision on any net mesh size limitation needs to be made by early fall, when fishers must order netting.

King said that the vast majority of the commercial fishers are willing to make adjustments, including the use of smaller mesh nets that reduce catch efficiency.

The states are pursuing a three-year grant from BPA, through the Northwest Power Planning Council, to fund the demonstration and test fisheries and related research.

Link information:
ODFW: http://www.dfw.state.or.us
WDFW: http://www.wa.gov/wdfw/

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3. SPORT ANGLERS POISED FOR BUSY BUOY 10 FISHERY

Anglers awaiting the Buoy 10 fishery, which opens Aug. 1, are likely to encounter a near-record return of fall chinook salmon in numbers that will continue to build through August.

The fall chinook run, projected to total about 659,800 fish, is expected to be the third-largest return since 1948. The estimates are for adult returns to the mouth of the Columbia River.

The annual "Status Report" for Columbia River fish runs and fisheries compiled by the Oregon and Washington departments of fish and wildlife shows a "minimum" run of 871,700 fall chinook adults in 1987 -- the most since fish managers began counting adult fall chinook and "jacks" separately in 1970. The total fall chinook return in 1987 was estimated to be 956,800 including jacks, younger chinook that return to the river before their reproductive prime. The following year was nearly as bountiful, 783,000 adults and a total run of 869,100 fall chinook including jacks.

This year's predicted adult return is not expected to quite match up either with runs in 1947 and 1948 that totaled 903,600 and 899,200, respectively, including jacks. But it's still expected to be a banner run.

The largest estimated "minimum" run since 1938 was 1,175,700 fall chinook, including jacks, in 1941.

The lowest estimated return, including jacks, was 235,700 in 1993.

Typically, fishing action varies on opening day but builds throughout the month, said Washington Department of Fish and Wildlife fish biologist Joe Hymer.

"Fishing should be smoking by mid to late August," Hymer said.

Adding to the action is the fact that about half the run is expected to be made up of "tules," lower Columbia hatchery-reared fish that are known for their strong performance on the line in the river estuary area.

The forecast includes a prediction that some 136,000 "Bonneville Pool Hatchery" fall chinook will return, the most since 1964. Those tules are bound for the Spring Creek National Fish Hatchery and tributaries to the Bonneville (Dam) pool.

The expected return of "upriver brights" is 273,800 fall chinook adults, well above the recent five-year average of 171,700. Those upriver brights are in large part wild fish destined for the Hanford Reach section of the mid-Columbia. The Mid-Columbia bright forecast is for 91,800 adults, nearly double the five-year average of 51,700.

The "lower river wild" forecast of 18,300 adults would be the largest since 1991 and a six-fold increase from the record low return of 3,300 adults in 1999. Those stocks are produced naturally in the Lewis River system, and to some extent the Cowlitz and Sandy rivers, according to the status report.

The prediction for a return of 133,000 "lower river hatchery" fall chinook would be the largest return since 1988.

Fishers are reminded that most of the Buoy 10 area -- except for a narrow ribbon along the Washington shore -- is in Oregon waters and subject to Oregon rules regarding party fishing. Although Washington moved recently to allow fishing to continue until every fisher on board catches his or her limit where a saltwater license is valid, Oregon still requires each fisher who has limited to stop fishing even if others have not caught their fish. Washington fishers are subject to Oregon rules while in most Buoy 10 waters.

Besides the fall chinook opportunity, Aug. 1 will also bring additional salmon fishing opportunity further upriver. Opportunities by area beginning Aug. 1 include:

-- Buoy 10 (Buoy 10 line to the Rocky Point/Tongue Pointline) -- Chinook, hatchery coho and hatchery steelhead. The daily limit is two salmon with a minimum size of 16 inches for coho and 24 inches for chinook. All chum, sockeye, and wild (unmarked) coho must be released. Two hatchery steelhead may be kept in addition to the salmon daily limit.

-- Rocky Point/Tongue Point line to Bonneville Dam -- Chinook and hatchery coho. Six salmon daily limit, no more than two of which may be adults. Minimum size 12 inches. All sockeye, chum, and wild (unmarked) coho must be released. Fishing for hatchery steelhead continues. In addition to the salmon daily limit, two hatchery steelhead may be retained.

-- Bonneville Dam to Highway 395 bridge in Pasco -- Open for chinook and coho. The daily limit is six salmon, no more than two of which may be adults. Minimum size 12 inches. All sockeye and chum must be released. Fishing for hatchery steelhead continues. In addition to the salmon daily limit, two hatchery steelhead may be retained.

Other areas above the Highway 395 bridge in Pasco currently are open for fishing under emergency rules. Anglers should consult the WDFW fishing hotline at (360) 902-2500 or the WDFW website at http://www.wa.gov/wdfw for information.

The Columbia River Compact, which sets commercial fishing seasons on the Columbia mainstem, meets Aug. 2 to consider non-Indian commercial salmon fishing options. The Oregon-Washington compact meets again on Aug. 15 to review salmon, steelhead and sturgeon stock status and to consider fishing seasons. Additional Compact meetings will be held throughout the late summer and fall to consider additional treaty Indian and non-Indian commercial season and to make run status updates.

Link information:

ODFW: http://www.dfw.state.or.us
WDFW: http://www.wa.gov/wdfw/

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4. NMFS AGREES TO INVESTIGATE 'WILD ONLY' LISTING PROPOSALS

By Barry Espenson

The National Marine Fisheries Service on Thursday announced it would officially consider petitions asking that the agency define and list only the "wild" fish for 15 separate Pacific salmon and steelhead stocks, forgoing ESA protection for hatchery fish in the same waters.

The petitions were filed April 29 by a coalition of 17 national, regional and local conservation groups.

The NMFS announcement follows NMFS' release Wednesday of a draft policy that would seek Endangered Species Act protections for wild salmon stocks in their natural habitats even if it means hatchery fish in the same waters must be protected as well.

The July 25 Federal Register notice notes that the agency "received two petitions from Trout Unlimited and several co-petitioners (hereafter, Trout Unlimited petitions) to redefine and list a total of 15 ESUs currently listed as threatened or endangered." One petition asks that the threatened Oregon coast coho "evolutionarily significant unit" be defined as including only naturally spawned fish and their progeny -- exclusive of all hatchery fish -- and to list it as threatened. The other petition seeks to define 14 ESUs as including only natural fish, and to list these ESUs as threatened or endangered.

The three-month "finding" released by NMFS this week says the "Trout Unlimited petitions present substantial scientific and commercial information indicating that the petitioned actions may be warranted." The agency is supposed to produce within a year of the petition filings a final finding that either accepts or rejects the "wild only" listing definition proposal. An acceptance would launch official rulemaking that would involve public hearings.

"NMFS has already committed to conducting status review updates for the 16 Pacific salmon and steelhead ESUs addressed in the CCFA (a separate petition asking that the Central California coast coho salmon be delisted) and Trout Unlimited petitions, as well as for nine other ESUs," according to the Federal Register notice. "The agency is also in the process of clarifying its policy on how it considers hatchery populations in making ESA listing determinations. NMFS will consider the information presented and the issues raised by these petitions in the course of revising its listing policy and conducting the coastwide status review updates."

Trout Unlimited and the others signing the petitions say the hatchery policy "working draft" released Wednesday by NMFS "spells out clearly that hatchery fish when mingled with wild fish - especially severely depleted wild populations - can further harm the wild populations. In those cases, the policy could recommend changes in listing status and/or hatchery operation."

"The line that science delineates so clearly between wild stocks and hatchery fish appears to be getting clearer by statute now as well," said Kaitlin Lovell of Trout Unlimited. "We're hopeful that NMFS' indictments yesterday of the harm that can come from mixing hatchery and wild fish coupled with their acceptance of these petitions today indicates there's a policy taking shape that is finally serious about wild fish protection."

The petitions, like similar actions over the past 10 months, rippled from a Sept. 10 order issued by Oregon U.S. District Court Judge, Michael R. Hogan. It called the NMFS' 1998 listing of Oregon coastal coho "arbitrary and capricious" and said the NMFS disobeyed ESA directives when it designated both hatchery and naturally spawning coastal coho as part of an "evolutionarily significant unit," then declined to include the hatchery population in the listing.

The "Hogan decision" has been stayed while it is weighed in the Ninth Circuit Court of Appeals. But Hogan's order immediately prompted six petitions last fall asking that West Coast fish stocks be removed from the federal endangered species list. The NMFS in

February concluded that five of six delisting petitions it received last year contained "substantial scientific and commercial information to suggest" that 14 of the 15 Pacific salmon and steelhead stocks addressed in the petitions could warrant removal from species list.

All say they are using the Hogan order as a precedent -- the conservation groups to secure exclusive protection for wild fish and the delisting petitions saying that if hatchery populations were counted in listing determinations, most of the listings would be repealed.

"Judge Hogan's ruling gave us a legal foothold to bring ESA protections for wild fish in this region up to date with the latest science," Lovell said in announcing the filing of the petition three months ago. "It's the wild fish that need protection, and the science increasingly shows that one thing they need protection from is hatchery fish."

The conservation groups said the 15 wild stocks being petitioned have and continue to face significant threats from many directions which, individually or in combination, threaten the survival of the stock. Those threats include predation, competition and genetic disruption from interactions with hatchery fish, destruction and modification of habitat from logging and agriculture, urbanization, dams, stream channelization and water withdrawals, and pollution from mining and industry.

The groups say the "wild-only" listings would result in no appreciable change in the management of the petitioned wild stocks, but could change management practices for hatchery-born fish.

The petitioned stocks include: wild Snake River spring and summer chinook, wild Snake fall chinook, wild Puget Sound chinook, wild lower Columbia River chinook, wild upper Willamette River chinook, wild upper Columbia chinook, wild southern Oregon/northern California coho, wild Columbia chum, wild Hood Canal summer-run chum, wild upper Columbia steelhead, wild Snake basin steelhead, wild lower Columbia steelhead, and wild mid-Columbia steelhead.

The groups signed on the petitions include Trout Unlimited, Oregon Council of TU, Washington Council of TU, California Council of TU, Idaho Council of TU, Oregon Trout, Washington Trout, Native Fish Society, Oregon Council of Federation of Flyfishers, Pacific Coast Federation of Fisherman's Associations/ Institute for Fisheries Resources, Oregon Natural Resources Council, Save Our Wild Salmon, American Rivers, Audubon Society of Portland, National Wildlife Federation, and Siskiyou Regional Education Project.

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5. SENATE PANEL BOOSTS CORPS' COLUMBIA RIVER BUDGET

Senate appropriators have agreed to increase the Army Corps of Engineers' budget for the Columbia River salmon mitigation by $6 million next year, to $87 million.

The funding was included in the FY2003 energy and water development spending bill, which was approved by the Appropriations Committee on Wednesday. The House Appropriations Committee, which traditionally acts first, has postponed its action on the bill until September.

The $87 million for Columbia and Snake river dam fish mitigation is $11 million less than President George W. Bush sought in his FY2003 budget request in February. But in its report on the bill, the Senate Appropriations Committee said that reduction "should in no way be considered any diminution of interest or support for these vitally important mitigation projects by the Committee. Rather it reflects the fiscal constraints with which the Committee is faced with."

Within the $87 million, the committee recommended that $300,000 be spent on a reconnaissance level investigation of Columbia River flood control operations to determine what changes, if any, would benefit endangered species, particularly salmon. "Evaluation beyond the reconnaissance phase is subject to agency review and congressional notification," the committee report said.

Overall, the committee provided $26.3 billion for energy and water bill, which also funds the Bureau of Reclamation and Department of Energy nuclear waste clean-up program. That is

$1.1 billion more than FY02 and $789 million more than Bush sought.

Most of the bill's increase went for homeland security and to restore $550 million in "shortfalls" in Bush's budget for water projects and improvements sponsored by members of Congress.

Bush's budget cuts, which led to the resignation earlier this year of undersecretary Mike Parker, threatened "the nation's economy and quality of life" and left the committee "no option but to step forward in support of these vital projects," it said. It increased the budget for the Corps of Engineers to $4.65 billion, $475 million above Bush's budget, and the Bureau of Reclamation to $956 million, $75 million higher.

Sen. Patty Murray, D-Wash., and other Northwest members succeeded in restoring $5 million to continue planning and studies for the Columbia River Channel Deepening project, which the president's budget omitted. No construction money was included for lower Columbia River ecosystem restoration, as part of the committee's decision not to initiate any new construction projects in FY03, but $300,000 to continue studies was provided.

Other Northwest Corps of Engineers construction projects receiving funds included:

- Bonneville Powerhouse rehabilitation, Phase II, $8.9 million;
- Columbia River Treaty Fishing Access Sites, $5.8 million;
- Willamette River, Ore., Temperature Control, $8 million;
- Howard Hanson Dam, Wash., Ecosystem Restoration, $7.5 million;
- Lower Snake River Fish and Wildlife Compensation, $4.6 million;
- The Dalles Powerhouse rehabilitation, $3 million.

Within the operations and maintenance budget for Columbia River locks and dams, the committee provided $400,000 above the budget request for Bonneville to implement the Federal Columbia River Power System Biological Opinion.

For John Day it increased the budget request by $1.6 million for significant safety repairs to the navigation lock, continued major rehabilitation evaluation to address significant foundation problems, and actions to implement the Columbia River Biological Opinion.

Other aspects of Columbia and Snake river salmon recovery are funded through the Bureau of Reclamation, which received $15 million, the same as last year, mainly for water acquisition and leasing.

The Senate committee said it provided $500,000 above the budget request for continued fishery habitat improvements in the John Day River Subbasin Project.

Murray said she gained funding for a number of Puget Sound fish habitat improvements and $800,000 for farming, tribal, environmental, and irrigation interests to work together to address water supply and fish habitat issues in the Walla Walla River Watershed. That is twice the amount in the president's budget.

The committee did not approve an increase in the Bonneville Power Administration's federal borrowing authority as sought by Northwest members and Bush. An aide to Murray said discussions with Budget Committee leaders were ongoing and that an effort to add the authorization would be made later.

BPA has asked for a $2 billion increase in loans over the next five years mainly to finance transmission line construction and improvements. Bush included $700 million in his budget.

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6. CORPS CHOOSES ECONOMIC PANEL FOR CHANNEL REVIEW

By Mike O'Bryant

The U.S. Army Corps of Engineers announced this week the makeup of two panels of economists who will evaluate the Corps' economic conclusions of a project to deepen the Columbia River shipping channel by three feet.

This is the second time the Corps has evaluated the economic justifications for the project. It released its economic analysis of the costs and benefits of the original project in 1999. However, the Corps had to go back to the drawing table when the National Marine Fisheries Service rescinded its earlier decision to grant a no-jeopardy opinion of the project. It released its revised analysis in early July 2002.

To confirm its findings, the Corps is calling on the economists to spend a week poring over its numbers. One panel is assigned to determine the costs of the project, while the other will review the benefits of deepening the channel, which is being sponsored by lower Columbia River ports to provide passage for deeper draft commercial ships. The economists will meet each day the week of Aug. 5, and take public comment and suggestions on Aug. 5 and Aug. 9.

"The objective of the technical review process is to determine whether the assumptions, methodology, and conclusions of the Corps' economic analysis of the benefits and costs of the 43-foot channel are reasonable," according to the Corps.

Although critics of the project have asked for an independent peer review of the Corps' calculations, they say the rigor, transparency and independence of the Corps' planned review will not restore the public's faith in the project. Instead, Nina Bell, executive director of the Northwest Environmental Advocates, and David Moryc, Lower Columbia River coordinator for American Rivers, call for a review by the National Academy of Sciences.

"We urge you to abandon this proposed peer review process and request that you have the National Academy of Sciences (NAS) conduct an independent review of this project. This is a well-established role for the NAS as it has previously evaluated Corps' projects and programs, and is currently conducting a broader investigation into the need for independent review of Corps' projects," they wrote in a strongly worded letter of July 19.

The Corps said that using the NAS for the review was not practical because the group of scientists would take too long and cost too much. "Also, their review functions are usually focused on large-scale scientific questions of national importance rather than project specific questions such as the accuracy of an economic justification," the Corps said.

The Corps had also considered using the Northwest Power Planning Council's Independent Economic Advisory Board, but settled on selecting the economists itself with the help of an independent facilitator. It said the IEAB is respected, but it lacks the "expertise in the navigation arena."

Bell and Moryc said a Corps' handpicked panel would introduce bias into the review, which could actually "undermine the credibility of the science and the policy decisions associated with this project."

They further said that the objective of the review is too narrow and that a thorough review should take much more time -- up to a year -- than the three weeks the Corps has in mind. In addition, they said the review should be much more transparent with more public overview and that the panel should represent broader disciplines than those selected by the Corps, including those of biology, hydrology and other ecological disciplines.

"Given this project's high cost for taxpayers and its potential negative effects on critical salmon habitat and the communities that rely on the lower Columbia River, a truly independent analysis should likewise involve a thorough look at the project's costs and benefits," Bell and Moryc said.

The Corps' original analysis found $2 in benefits for deepening the channel to every $1 in costs. In its latest analysis, the Corps calculated lower shipping benefits than in its 1999 report, but also revised downwards the cost of dredging the channel. The new economic study found that for every dollar spent dredging the channel, the region and nation will reap $1.46 in economic benefits.

The revised report concludes the project will cost $156.2 million, a drop of over $30 million from the original price tag of $188 million. That includes both dredging operations and the cost of the seven proposed environmental restoration projects. The benefits of deepening the channel, specifically those benefits of more deeper draft ships using the river and greater shipping efficiencies, would bring in $18.3 million per year over 50 years to the national economy. That's down from the previous findings of $34.4

million in annual benefits.

The Corps is using RESOLVE, a neutral, non-profit organization (according to the Corps), to facilitate the two panels of economists. Those panelists include:

Benefit Review Team:
Dr. Ken Casavant, Washington State University, Pullman, Washington
Dr. Kevin Horn, AECOM Consulting Transportation Group, Fairfax, Virginia
Dr. Wayne K. Talley, Old Dominion University, Elizabeth City, North Carolina
Daniel S. Smith, The Tioga Group, Inc., Moraga, California

Cost Review Team:
Nancy Case O'Bourke, P.E., Case O'Bourke Engineering, Inc., Miami, Florida
Gregory L. Hartman, P.E., Dalton, Olmsted and Fuglevand, Inc., Silverdale, Washington
Eric Salamone, US Army Corps of Engineers, New Orleans, Louisiana

The panel will meet at the Fifth Avenue Suites in downtown Portland, Ore. the week of August 5, and open two sessions -- Aug. 5 and 9 -- to the public. Panelists will take technical information related to the Corps' economic analysis at those meetings. The Corps said the presentations must be arranged in advance.

Link information:
US Army Corps of Engineers -- https://www.nwp.usace.army.mil/
Northwest Environmental Advocates -- www.northwestenvironmentaladvocates.org
American Rivers -- www.amrivers.org

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7. COLUMBIA CHANNEL DEEPENING PUBLIC MEETINGS PLANNED

The U.S. Army Corps of Engineers will host a series of public meetings this summer on its draft Supplemental Integrated Feasibility Report and Environmental Impact Statement for the Columbia River Channel Improvement Project.

The Corps' proposals include deepening the federal navigation channel between the Pacific Ocean and Vancouver, Wash., by 3 feet. Additionally, the Corps plans to implement nine restoration features for aquatic and wildlife species.

In 1994, the Corps' Portland District began the feasibility study to evaluate improvements to the Columbia River federal navigation channel. The study's non-federal sponsors are the six lower Columbia River ports - Portland and St. Helens in Oregon, and Longview, Kalama, Woodland and Vancouver in Washington.

The first public meeting -- an informational session for the Corps and the public to discuss the details of the supplemental report - will be held Monday, July 29, at Warrenton High School, 1700 SE Main St., Warrenton, Ore. The session will begin at 5 p.m. No public testimony will be taken.

Public hearings will be held in Vancouver, Wash., on July 31; Longview, Wash., on Sept. 5; and Astoria, Ore., on Sept. 10. Each meeting will include one-on-one discussion opportunities and public testimony.

The Warrenton session will be an opportunity for the Corps, project sponsors and federal and state regulatory agencies to present information and answer questions about the various aspects of the project early in the comment period. The Corps and sponsor ports will accept written comments at this session and will return Sept. 10 - in Astoria - to accept oral testimony.

Additionally, interested parties will be welcome to observe the opening and closing sessions of the technical review panel as it discusses the validity and accuracy of the project costs and economic analysis, and receives technical presentations. The panel will report on its findings Friday, Aug. 9.

The public comment period for the draft supplemental officially began July 12, with the filing in the Federal Register. The report is available at https://www.nwp.usace.army.mil/. The formal comment period closes Sept. 15.

The purposes of the proposed project are to improve transport of goods on the navigation channel by improving the channel's ability to handle deep-draft vessels and to provide ecosystem restoration for fish and wildlife habitats. The need for navigation improvements has been driven by the steady growth in waterborne commerce, and the use of larger and more efficient vessels to transport bulk and containerized commodities. As the use of deep-draft vessels grows, so do limitations created by the existing channel dimensions.

The existing 40-foot channel prevents many of the larger vessels from transiting the river at full capacity, according to the Corps.

Following consultations for threatened and endangered species with the National Marine Fisheries Service and the U.S. Fish and Wildlife Service, the Corps updated its original report on the Columbia River Channel Improvement Project. The Corps developed new costs, reexamined the benefits and the benefit to cost ratio, and updated the report with new information that has become available since the report was first issued in 1999.

Link information:
Corps of Engineers: : https://www.nwp.usace.army.mil/pa/

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8. FEDERAL JUDGE RULES AGAINST SHOOTING SAWTOOTH WOLVES

By Barry Espenson

U.S. District Court Judge B. Lynn Winmill on July 19 opted against a grazing ban on eight allotments in Idaho's Sawtooth National Recreation Area this summer, but did rule that wolves preying on domestic animal within the federal preserve cannot be killed for their transgressions.

"The Court finds that any wolf predation in the SNRA during this summer season up to and including September 1, 2002, shall not be used as a basis for taking any action against individual wolves or wolf packs under the Wolf Control Rules," Winmill wrote.

"On the other hand, if the wolves commit predation outside the SNRA, which would require action under the Wolf Control Rules, they are subject to the Rules' sanctions, even if they move into the SNRA," Winmill concludes.

Winmill's decision follows a motion filed June 25 by Western Watersheds Project and the Idaho Conservation League to close the allotments to livestock grazing. That legal request attempted to use as precedent a June 13 Winmill order that said the Forest Service was in violation of the 1972 federal Organic Act by failing to consider whether the grazing is substantially impairing the wolf populations and ordered the agency to complete the required analyses.

Winmill pointed out in that June 13 order that Congress in the act "listed specific values that it wanted conserved and developed, such as scenic, historic, and wildlife values. Congress also directed the Forest Service to manage the utilization of timber, grazing, and mineral resources, so long as that utilization did not 'substantially impair' the other purposes of the SNRA."

The judge's earlier order also said that the Forest Service is in violation of the federal Rescissions Act passed by Congress in 1995. That act was created by Congress to "compel the Forest Service to set up a schedule to conduct NEPA analysis on each grazing allotment in the National Forest System." That schedule was established, but has not been met in the SNRA, the judge said.

Winmill, in the June order wrote that the Forest Service must reconcile the differing mandates of the Organic Act and the U.S. Fish and Wildlife Service's Wolf Reintroduction Program. The reintroduction plan deliberately classified the wolves that were reintroduced in areas of Idaho and Wyoming as "non-essential experimental" populations within the gray wolf Endangered Species Act listing. The non-essential status allows more latitude for the U.S. Fish and Wildlife Service to call on lethal control of wolves that repeatedly prey on domestic livestock. Gray wolves are listed under the Endangered Species Act.

Winmill said that his order takes a different path in granting the plaintiffs relief in the case, denying a request that the sheep and cattle be pulled from the federal lands but satisfying the plaintiff's ultimate goal -- that wolves not be killed in the recreation area while the Forest Service addresses the violations of federal law. The plaintiffs have insisted that if the livestock is present, there is potential for predation and wolves would ultimately be killed in response.

"Sometimes… justice requires that a court stop short of exercising its full authority. That is the case here," Winmill said. "While the Court may have the power to enjoin grazing, the heavy hand of such an injunction would employ a dull meat cleaver to do the work of a sharp scalpel.

"It is not entirely clear that the mere presence of livestock is causing substantial impairment of wildlife values. And the wholesale removal of livestock at this early stage of the litigation would be inconsistent with this Court's past decision holding that there is no intractable conflict between then Organic Act and the Wolf Control Rules," Winmill wrote.

He encouraged the federal state and private entities involved to find new ways to protect livestock without removing or killing wolves.

Many techniques are already being employed but "there is no sense here that all good ideas have been exhausted. The Court is convinced that keen insight, calm analysis, and sound judgment -- coming from the parties rather than by Court order -- will work a solution," the judge wrote.

Winmill in his July 19 order enjoins both the Forest Service and the USFWS from taking any action against wolves for predation within the SNRA through Sept. 1. Though the USFWS is not a defendant in the case, the judge theorized that the two federal agencies are working in "active concert with regard to the wolf reintroduction program."

The federal government has not decided whether or not it would appeal the judge's decision, said Dana Perino, a Department of Justice spokeswoman.

While the decision stops short of prohibiting grazing on the allotments, the plaintiffs say it sends a clear message to livestock operators in the SNRA: Wolves will be protected, even at the cost of sheep or cattle.

"For the first time a federal judge has ordered a stop to the killing of wolves," said Jon Marvel, executive director of WWP.

"Every pack in the White Cloud Mountains, some of Idaho's wildest country, has been destroyed," said ICL's Linn Kincannon. "For this summer at least, that won't happen. And hopefully we'll have a new pack in the SNRA before long."

In April 2002, federal agents killed the entire Whitehawk pack of 11 wolves near the SNRA under the reintroduction plan rules after repeated depredations on livestock. The White Cloud and Stanley Basin wolf packs were eliminated in 2000 and 2001, according to the plaintiffs.

The Whitehawk pack was believed to be the lone remaining population in the SNRA. However, USFWS agents recently observed other wolves in the area. One wolf was reported in the vicinity of Fourth of July Creek. Another was seen near Stanley. Three others were observed in Pole Creek at the southern end of the Sawtooth Valley, according to the plaintiffs.

The judge said his remedy "recognizes the Forest Service's violations, and would draw a proper balance between the primacy of the value of wildlife under the Organic Act and the conditional value of grazing."

If wolves commit predations outside the SNRA this summer, they will be subject to wolf control sanctions. But Winmill said it is "in the best interests of the (livestock) permittees to work together with the Forest Service and FWS to seek ways to protect livestock."

Winmill made clear that his decision binds not only the Forest Service but also USFWS in protecting wolves in the SNRA.

W. Alan Schroeder, an attorney for the

with the decision in that Jon Marvel's crew was trying to leverage their procedural victory into a complete shutdown of grazing, and they were unsuccessful." The Flying Triangle's Bill Brailsford holds four of the eight allotment permits.

Brailsford now has 700 sheep ewes with twin lambs on the allotments and plans to move 1,800 dry ewes to the area soon, Schroeder said. With no alternative pasture available, the ranch could have taken a big financial hit.

If the allotments had been closed Brailsford "would have had to prematurely market his lambs and have a fire sale on the ewes," Schroeder said.

The USFWS' wolf recovery coordinator, Ed Bangs, said that his agency intends to comply with the order, and await a Justice Department decision on how to respond. Meanwhile, he did not anticipate trouble in the SNRA.

As the plaintiffs noted, individual wolves have wandered in and out of the recreation area. And the Wild Horse Pack, which lost its Alpha female last year and did not den and produce pups, has also ventured into the area. But no wolves have adopted a home range within the recreation area. But it is only a matter of time, Bangs said.

"When you remove a pack (as was the Whitehawk) you create a vacuum" that would almost certainly draw in more wolves, Bangs said. "By this time next year there'll be pups and everything else."

The wolves have shown their ability to prosper. A few dozen transplanted from Canada to central Idaho and the Yellowstone region in 1995 and 1996 have blossomed into a population that now includes 550 adults and 200 pups, Bangs said. And while only a small percentage prey on domestic livestock, those that do are incorrigible.

"Wolf control is a necessary part of wolf management," Bangs said.

In the past three years, at least 27 wolves have been killed or removed from areas in or near the SNRA due to conflicts with livestock.

Despite the presence of wolves, some 4,470 sheep and 2,500 cattle are allowed to graze on 28 Forest Service allotments in the SNRA, according to the conservation groups.

"ICL and WWP wanted to protect wolves, and we did," said Kincannon. "We're excited for the future of wildlife in the SNRA and the Rocky Mountain West in general."

"This order is only part of the solution for the SNRA that we expect the court to order," said Laird Lucas of the Land and Water Fund of the Rockies and lead attorney for WWP and ICL. "We will be appearing before the judge again in two weeks to talk about a timetable to fully analyze the SNRA allotments and determine whether grazing is substantially impairing wildlife and recreation.

A hearing is scheduled July 30 to discuss the timetable for the Forest Service to complete assessments required under the Organic and Rescission acts.

"If the Forest Service doesn't do analyses in all due speed, we will seek similar protection to prevent wolves from being killed next summer."

END PART 1

BPA could make the request again next year, as well as look for other bills this year to get the borrowing authority, including an economic stimulus package or a bill to support critical infrastructure.

BPA - a federal power-marketing agency that provides about half the Northwest's power - owns and operates about 15,000 miles of power lines, or about three-quarters of the region's high-voltage electric grid.

A BPA official said the agency expects to reach its $3.75 billion borrowing cap by the end of 2003 or early 2004, when money will be needed for more transmission lines.

"We didn't know we were going to reach (the end of) our line of credit so quickly," said the official, who spoke on condition she not be identified.

"With the energy crisis, with so many new developers wanting to site development in the Northwest, that means there is a new demand for interconnection that we didn't have before."

The agency will also need to boost conservation and improve efficiencies in its hydroelectric system, the official added.

If BPA gets the $2 billion, the official estimated about $500 million each may go toward generation and conservation, and about $1 billion may be directed to transmission.

However, Save Our Wild Salmon, a coalition of conservationists and recreational water users, said it was concerned the proposal could further harm endangered salmon, because the request did not require a commitment to improve fish and wildlife protections.

Ball, Crystal A - DC/WASH

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THE COLUMBIA BASIN BULLETIN:
Weekly Fish and Wildlife News
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1. CHANNEL DEEPENING BIOP SPARKS REACTION

By Mike O'Bryant

Biological opinions released by two federal agencies last week said a project that will deepen by three feet the Columbia River shipping channel from Portland, Ore., to Astoria will pose no jeopardy to 13 species of salmon, steelhead and cutthroat trout listed, or being considered, under the federal Endangered Species Act.

The favorable BiOp gave federal approval to the Army Corps of Engineers to deepen the channel from 40 feet to 43 feet to accommodate deeper draft cargo ships.

Even with the favorable rulings from the National Marine Fisheries Service and the US Fish and Wildlife Service, the Corps still must get water quality approvals from Oregon and Washington, complete an economic study that justifies the project's costs and benefits, and appeal to Congress for funds before the dredging can begin.

The BiOp requires the Corps to monitor the effects of its dredging operations and to shut down dredging if it appears to impact listed species. While it does not require the agency to mitigate for impacts, the BiOp does suggest it tackle six estuary restoration measures, all of which the Corps offered in its January biological assessment, that would restore over 3,400 acres of fish habitat in the lower Columbia River estuary.

Opponents of the dredging project reacted to the no-jeopardy BiOp with anger and are threatening lawsuits. However, opponents say that due to the political power backing the channel deepening project -- six lower Columbia River Ports, including the Port of Portland, Oregon Gov. John Kitzhaber, and the Oregon and Washington legislatures, all support the project -- the result is what they expected.

"It shouldn't have been a surprise," wrote Peter Huhtala, executive director of the Columbia Deepening Opposition Group in Astoria. "NMFS is supposed to protect salmon and their habitat, but the agency is also caught here in a nasty squeeze by the U.S. Army Corps of Engineers along with another army of special interest political forces. It's tough dancing in tight quarters."

Huhtala added that, for groups who oppose the project, the BiOp is encouraging because of "its wealth of contradictions" that "should help ensure a positive outcome for the coming lawsuits."

"The document is peppered with descriptions of how salmon will die during dredging, blasting and dumping. It anticipates short-term harassment and contamination of the already over-stressed fish," he said. "NMFS admits uncertainty about longer-term degrading of the estuary. They even declare that the deepening 'will adversely affect' Essential Fish Habitat. But seeming to 'hear no evil (or science, for that matter)' NMFS blesses the Corps with an agreement to let the destruction begin."

NMFS also approved the project in December 1999, but reversed that decision in August 2000 when faced with new scientific information, including how contaminants from the dredging operation would affect endangered species, and with a lawsuit brought against NMFS by Northwest Environmental Advocates. NMFS said its latest conclusion came after a more complete review finished jointly with U.S. Fish and Wildlife, the Corps and the participating (sponsoring) Columbia River port districts. The only lower river port not signing on to the pact is the Port of Astoria.

"We've taken a very thorough look at the project's effects," said Bob Lohn, NMFS regional administrator. "The best science available to us shows that this project will not jeopardize listed species."

Scientific review

Part of that scientific review included working last year with an independent panel of seven scientists organized by the non-profit Sustainable Ecosystems Institute. After this review with SEI, the Corps rewrote its biological assessment for the project and submitted it to NMFS on January 3, 2002. The new BiOp adopted much of that assessment.

"We see this as a huge political juggernaut," said Bob Heinith of the Columbia River InterTribal Fish Commission. "There is a common perception that the science has now been fully-vetted. We beg to differ."

Although there has been additional modeling work completed since the 1999 BiOp, Heinith said no new data was used in the modeling, so the new BiOp isn't any more robust than the 1999 document.

"…NMFS failed to consider the 'best available science' in many cases in the BO. The bottom line is that this opinion is even weaker for salmon than the 1999 Opinion, considering the 1999 opinion at least provided for stronger compliance and required some 5,000 acres of estuary habitat mitigation, where the new BO requires none," Heinith said in a brief prepared by CRITFC.

However, the Corps said that it provided much more detail in its biological assessment than it had in 1999. It added six restoration measures to the three proposed in its first assessment (although acres recovered fell by more than one-third), described how it will dredge to minimize environmental impacts and outlined a monitoring plan for before, during and after construction, as well as a research plan.

Laura Hicks, Corps manager for the channel deepening project, said the agency has worked closely for the past 18 months with NMFS and USFWS to define the problems contained in its first biological assessment and to address areas that needed more work. That's also why there are very few differences between the assessment and NMFS' BiOp, she said.

"We now have a pretty solid product," Hicks said. "It helped to work with the other agencies in the beginning."

Northwest Environmental Advocates disagrees with the comprehensiveness of the BiOP. It said that NMFS looked only at the incremental impact of the project on the ecosystem, failed to account for the long-term effects of this and all the dredging projects over the past century, and that the monitoring plan is a gamble. "The agencies continue to make decisions based on insufficient information about how the estuary works and how salmon use it," NEA said in a statement.

"Although the lower Columbia River and the threatened and endangered species that rely upon it have been in a dramatic state of decline for nearly a century, NMFS, in its latest opinion, has chosen to view the project only in terms of incremental harm as of today," NEA said. "In doing so, NMFS is choosing to gamble on a monitoring and evaluation program that will determine at some later date and time, while dredging is underway or even completed, what the effects of the project will be on the species they are charged with protecting."

According to the BiOp, the indirect impacts, which could occur any time during the dredging, will change water depth, water velocity in certain parts of the river and the distance salt water flows up-river. NMFS found that those changes would mostly occur in the navigation channel, not in sensitive rearing areas, such as marsh and swamp habitat in the estuary.

Direct impacts are the results of dredging. Protective measures include restrictions, such as keeping the dredge "cutterhead" on the river bottom where there are no fish so fish won't be sucked-up or entrained during the operation. Measures also will include a restriction on blasting when fish are present and disposing of dredged spoils in deeper water to keep silt away from fish. However, unlike other dredging approvals NMFS has given, it did not impose seasonal work windows (timing of the work only when fish are not present), but allows the Corps to work year round.

CRITFC said the impacts are not as inconsequential to salmon as NMFS claims, based on new information from Oregon State University. Heinith said researchers studying radio-tagged juvenile and adult salmon found that the fish do use the navigation channel and they do swim deeper than 20 feet. "That's where all the dredging will occur and where the plumes (of dredged sediment) will be released," Heinith said.

He also worried that, with saltwater moving further upstream after the channel is deepened, migration timing for juveniles would change and that could affect survival.

Monitoring and adaptive management as mitigation

If NMFS had decided the project jeopardized endangered species, it could still have approved the project, but required the Corps to mitigate for the impacts of dredging. In this case, NMFS followed a fine line, finding that endangered species could be directly or indirectly impacted, but instead it "negotiated protective measures that will minimize and avoid direct impacts to listed fish," according to the BiOp's executive summary.

The mitigation is a "robust monitoring and adaptive management program," according to NMFS' Cathy Tortorici. She said adaptive management will begin in 2003 and continue through and beyond the project's operation. If NMFS does find something that doesn't line up with the conclusions in the document, then it can order mitigation, a modification of the operation or stop the project all together, she said.

Habitat restoration projects key

Although the agency said they are not intended as mitigation measures, NMFS also approved a series of ecosystem restoration projects that will restore 3,420 acres of habitat for listed fish and make available 38 miles of inaccessible salmon habitat. The Corps will restore an additional 2,250 acres at Shilapoo Lake near Vancouver, Wash., that does not specifically benefit listed fish.

But, these are only suggested actions which the Corps is not required to do, according to Heinith. NMFS agrees, but says the Corps and participating ports have already committed to pay for the projects and all will be included in the channel deepening costs in the Corps' request to Congress for funding.

In fact, Hicks said, the Corps hopes to have some or all of the restoration complete by the time it begins the dredging, which would begin no sooner than 2003.

This is a change from the previous BiOp in which the Corps agreed to restoration projects that would include over 5,000 acres. Tortorici said that NMFS reviewed all the projects and the difference now is that all projects in the new BiOp are closely tied to benefits for fish, whereas those in the 1999 BiOp were not necessarily linked to fish benefits or to funding. "Yes, there are fewer acres, but they are all integral to the project," she said.

In addition, Hicks said the Corps could not give a firm commitment to fund the projects in the 1999 BiOp, whereas that commitment is now present.

Huhtala said some of the restoration projects are "bizarre," especially one that would dump 800,000 truck loads of sediment into a basin east of Tongue Point, which would affect a net-pen fishery worth millions of dollars per year to the local economy.

Lovenia Warren, of Salmon For All, a commercial fishing group in Astoria, values that fishery at nearly $7 million for the community. "(It's) ridiculous to claim that projects such as dumping dredge spoils over a productive fishing area, would benefit salmon," she told the Daily Astorian. "In reality, these 'ecosystem restoration' projects will do little, if any, good for the listed salmon. Once again, the fishermen suffer as a result of poor decision making by the federal agencies."

Another restoration project "destroys historical salmon fishing grounds while providing enhanced salmon feasting opportunities for birds," according to Huhtala. That is the 161-acre Miller/Pillar habitat restoration in which water between Miller Sands and Pillar Rock would eventually be filled to create shallow water next to Rice Island. The island, which was created by the Corps with dredge spoils, at one time attracted over 10,000 pair of nesting Caspian terns, which bred and fed on juvenile salmon. A three-year multi-agency plan to move the terns to East Sand Island closer to the ocean and away from juvenile salmon, many of which are listed species, was declared successful this year. However, Huhtala said this restoration project will impact fishermen in the lower river.

"Seventeen families of fishermen have been supported by that section of river for several generations," Huhtala said in January. "This will make it shallow and that is an economic problem for us."

"We recognize the public has a concern (about these projects)," Tortorici said. "However, a much broader discussion of the economic impacts of these projects will occur with the supplemental Environmental Impact Statement and economic review," a public process that should begin in July. She commented that the projects are intended to protect endangered species. The net pen fishery is a terminal fishery that evolves out of an Oregon Department of Fish and Wildlife hatchery program.

NEA said that neither NMFS nor the Corps really know what the long-term effects of the project will be or what benefits the restored sites will provide. "The agencies continue to make decisions based on insufficient information about how the estuary works and how salmon use it," NEA said.

However, Tortorici said NMFS evaluated all the projects and the results are in the BiO

Lawsuit in the future?

Heinith said CRITFC is unlikely to pursue a court solution to the NMFS decision because it already is tied up in a number of issues and one more would stress the tribes' resources. While he declined to provide specific information, he said others may soon file in federal court. NEA, which sued NMFS over its 1999 BiOp, was not available for comment

While obliquely referring to court action, Huhtala thinks some of the problems he sees in the project could be addressed in processes yet to come. He said the "environmental hurdles" are high.

"Case in point, the states of Oregon and Washington resoundingly denied water quality permits under the Clean Water Act back in 2000," he said. "Guess what? The substance of the project hasn't changed, except for the worse. The state agencies might choose a political decision similar to NMFS, but they shouldn't have much luck in court either."

He also pointed to the upcoming public economic review, which the Corps will begin in July. The Oregonian reported in March that the Corps' 1999 estimates of the project's economic benefits were more than double what reporters could calculate as benefits.

The reason the project is moving forward at all is that the lower Columbia River ports believe a deeper channel would improve trade. They predict a deeper shipping channel would attract larger ships and bring more business to Columbia basin cities and farmers. According to Dave Hunt, executive director of the Columbia River Channel Coalition, the additional three feet of depth would allow a ship to carry 6,000 more tons of grain or 300 more containers than they can now. About 40,000 jobs depend on the Columbia River maritime economy at an average wage of $46,000 per year.

Link information:
National Marine Fisheries Service: www.nwr.noaa.gov
U.S. Army Corps of Engineers, Portland District:www.nwp.usace.army.mil
Columbia River Channel Improvement Project Biological Assessment:

www.nwp.usace.army.mil/issues/crcip
Northwest Environmental Advocates: www.northwestenvironmentaladvocates.org
Columbia River Channel Deepening Coalition: www.channeldeepening.com
Sustainable Ecosystem Institute: www.sei.org

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2. GENETIC ANALYSIS: METHOW STOCKS HAVE BECOME ONE

By Barry Espenson

A recently released draft Methow River Basin spring chinook genetic analysis says that it is too late to segregate an Upper Columbia salmon melting pot by phasing out the so-called "Carson" bloodlines in favor of "Methow composite" stock in hatchery operations.

The two stocks are virtually one in the same, according to the draft study produced by scientists for the Columbia River Inter-Tribal Fish Commission and the Center for Salmonid Species at Risk at the University of Idaho. And it is unlikely that any of the "wild," naturally spawning spring chinook are true descendants of the fish that populated the basin at the beginning of the 20th century.

The study supports the long-held opinion of CRITFC's science and policy experts that the federal government erred in its creation of the Upper Columbia River spring chinook "evolutionarily significant unit." Natural spawners in tributaries to the Columbia above Rock Island Dam and select tributary hatchery stocks were listed as endangered under the Endangered Species Act in 1999. The Carson stocks were not included in the ESU and as a result are being phased out as broodstock at the Winthrop facility run by the U.S. Fish and Wildlife Service.

"The major finding of this study indicates Methow Composite and Winthrop Hatchery stocks are not substantially reproductively isolated within the Methow drainage and therefore the exclusion of the Winthrop Hatchery Winthrop Run from the upper Columbia River chinook salmon ESU should be re-evaluated," the study concludes.

The "Winthrop Run" is defined in the paper as Winthrop National Fish Hatchery broodstocks that were originally transferred, primarily, from the Carson National Fish Hatchery on the lower Columbia. The Methow composites, the report says, are an "admixture of adults putatively destined for the Chewuch and Methow mainstem" that have been reared at the nearby Methow state fish hatchery.

The study analyzes data produced from the examination of tissue samples from 536 spring chinook salmon collected in 1998-2001. The samples were taking from both ESA listed and non-listed stocks, from the carcasses of naturally spawning fish and from fish in the hatcheries.

"Our results indicate that we have essentially one population, or two at the most" in the Methow basin, said Andre Talbot, one of the study's authors. But if there are two populations as suspected from the analysis and review of genetic materials, they share all of the same habitats.

"At the very least, it is clear that all hatchery stocks have similar ancestry, which is shared with adults sampled from the spawning grounds," the report concludes. Talbot, lead author Chris Beasley, John Whiteaker and Doug Hatch of CRITFC and Madison Powell of the UI's research facility staff were involved in drafting the report that has been circulated for review. On the review list were geneticists and scientists with the NMFS, the USFWS and Washington Department of Fish and Wildlife. The USFWS operates the Winthrop and Carson hatcheries and the WDFW manages the Methow hatchery.

"We do want to integrate their comments into it," Talbot said. Those comments are just starting to come in.

"It's being heavily criticized, I am sure," said Talbot. Tribal scientists have long had scientific differences of opinion with the state and NMFS officials about the degree to which the upper Columbia spring chinook stocks have become homogenized.

It is not new information that the stocks are similar genetically, said Mike Ford of NMFS' Seattle science center. But the NMFS and WDFW have said there is enough genetic distinction between the Carson and Methow composite stock to warrant the phasing out of the Carson stock.

Ford said he had read through the draft study, but had not studied it in enough detail to comment on its scientific merit.

"We're still in the process of evaluating it," Ford said.

The federal and state agencies and hatcheries are trying to rebuild the beleaguered spring chinook population by rearing what are believed to be more endemic fish. It is hoped they will return as adults and spawn. Most believe that stocks that have adapted over time to a specific locale or environment are better suited to survive and reproduce there.

The draft study agrees but says genetic lines have become too blurred as a result of numerous assaults on the fish themselves and long-running human attempts to maintain the stocks with hatcheries. Talbot says the vast majority of the natural spawners in the basin are of hatchery origin.

"The similarity of these two stocks suggest management either include or exclude both stocks from the upper Columbia River spring chinook salmon ESU," the study says.

"In cases where distinct genetic divergence persists between listed and non-listed stocks, the literature overwhelmingly supports exclusion of non-listed stocks in order to prevent homogenization with listed stocks with the goal of preserving genetic diversity," the study said.

"However, there may be instances where euthanizing non-listed stocks may actually be detrimental to the listed populations, particularly if homogenization between the listed and non-listed stocks has occurred, as appears to be the case with the Methow Composite and Winthrop stocks in the Methow River. In such instances, alternative strategies for choosing hatchery broodstock with the aim of co-adapting the population to both the wild and hatchery environments may be beneficial…."

The basin witnessed a boost in adult returns in 2000, with existing policy prompting hatchery managers to destroy unneeded Carson-origin fish. The population ballooned further last year as favorable ocean conditions enhanced the fishes' survival chances during their saltwater maturation. Tribes, and many local citizens and organizations pushed for a better utilization of the returning Carson stocks.

An agreement was hammered out between the state, federal government and the tribes that allowed the hatchery managers to fill their egg needs from Methow composite returns to the state hatchery and spawners trapped in the Twisp and Chewuch rivers. Unneeded hatchery returns, including Carson stock that had been released as juveniles from the Winthrop hatchery, were allowed to seek spawning habitat. Those releases were stopped two years ago.

"If you're trying to rebuild a run and you're arbitrarily excluding one group, you are delaying recovery," Talbot said of the Carson stock. The spring chinook stock needs all the help it can get, especially since its home is high up in the Columbia River basin. The stock has low survival rates in large part because of their strenuous migration up and down the hydrosystem corridor, he said.

"We feel strongly that you should use them all unless there are compelling (genetic) differences," Talbot said. "We found none. In fact we found plenty of evidence that there has been mixing" of stocks.

The study's abstract and introduction say that it is virtually impossible that truly endemic stocks remain. Between 1915and 1930 a logging-related dam existed on the lower Methow River that "essentially blocked passage" into the basin. Historic harvests from the end of the 19th century also took a heavy toll, in excess of 80 percent of chinook stocks. And during the 1939-43 construction of Grand Coulee Dam, fish mangers captured all spring and summer chinook destined for the Upper Columbia and outplanted them in the Methow basin and other tributaries in the area or spawned the fish. Many of those trapped fish that were infused into the area's hatchery processes were bound for tributaries upriver of Grand Coulee.

Since that time stock transfers, many of them from Carson, have been commonplace in Methow basin hatchery operations, the study says. Carson broodstock "was derived as a sample of spring chinook passing Bonneville Dam, the lowermost Columbia River dam, effectively an admixture of spring chinook destined for the Snake and upper Columbia rivers," the report says. "Interestingly, the 'Carson stock' transfers were believed to be predominately of upper Columbia River origin."

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3. NMFS ISSUES TECHNICAL REPORT ON CASPIAN TERNS

By Barry Espenson

A draft report now out for technical review likens the impact of predatory Caspian terns on migrating Columbia Basin juvenile salmon and steelhead to those brought by human activities that increase fish mortality.

"Caspian tern predation on juvenile salmonids significantly affects recovery, however removing all tern predation will not, by itself, lead to full recovery of any listed salmon and steelhead stock," says the document released late last month by the National Marine Fisheries Service study.

"The evaluation of "Caspian tern predation on Salmon and Steelhead Smolts in the Columbia River Estuary" is one of three reports called for in the settlement of a lawsuit that pitted bird advocates vs. salmon advocates.

Those three necessary technical reports include: (1) Avian predation analysis to determine levels of predation that do not impede salmon recovery; (2) Status Assessment of Caspian Terns; and (3) Feasibility study of potential Caspian Tern nesting sites in the Pacific Northwest. The first two are now out in draft form. The third is not yet complete.

A successful lawsuit filed by the National Audubon Society, Defenders of Wildlife, Seattle Audubon Society and the American Bird Conservancy threatened to halt a plan relocate what is considered the world's largest Caspian tern colony. The goal was to shift the birds from their favored site, Rice Island, to a locale at the river's mouth, East Sand Island, where they would consume fewer juvenile salmon and steelhead and more marine fishes.

The plan shifted most of the birds in 2000 and all of the birds nested at East Sand in 2001, reducing smolt consumption from and estimated 11.7 million in 1999 to 7.3 million and 5.9 million respectively in 2000 and 2001.

The plaintiffs in the lawsuit argued vehemently that Caspian terns are being scapegoated for the demise of salmon. The fish-eating birds are a natural part of the ecosystem, the bird conservation groups say. The federal Columbia-snake hydrosystem and other human uses that alter salmon's freshwater habitat are more the culprits, according to the plaintiffs.

U.S. District Court Judge Barbara Rothstein agreed in large part. In an August 2001 injunction imposed Rothstein prohibited any harassment of the birds in the estuary or manipulation of habitat and threatened implementation of the management plan this year. The defendants, the U.S. Army Corps and U.S. Fish and Wildlife Service had appealed the decision to the Ninth Circuit Court of Appeals, which steered the two sides toward settlement negotiations. The Corps is in charge of the dredging. The USFWS has responsibility to protect the migratory birds that fly north to nest and rear their young during the late spring and summer.

Rothstein ruled that the Corps and USFWS acted illegally when they initiated a plan to turn the world's largest colony of Caspian terns away from their preferred nesting site without the benefit of a full environmental impact statement.

The draft report is more of the same, according to Gerald Winegrad, vice president for policy for American Bird Conservancy.

The NMFS document is "woefully inadequate and poor science," Winegrad said. He said the calculations continue to exaggerate the impact the tern predation has on wild, listed fish. Winegrad called the birds' impact -- as measured in smolt-to-adult returns, miniscule compared to the impacts of hydrosystem, the destruction of habitat, harvests and other man-caused factors.

"There is no direct correlation that has even been scientifically shown between the Caspian tern predation and the adult return," he said.

The plaintiffs in the case have commissioned several experts in prey-predator relationships to comment on the draft documents. Comments are due by July 1.

Those comments and the comments of others will be considered, and the documents revised with final reports due at the end of August, according to Tara Zimmerman of the USFWS.

"They will become a part of the information base we use to develop alternatives and select where we want to go from here," Zimmerman said. The settlement agreement calls for the development of a final environmental impact statement that outlines a long-term management plan with protections for the terns.

The life cycle model developed at NMFS' Northwest Fishery Science Center -- the Cumulative Risk Initiative -- was used to estimate impacts of the tern predation on the "population growth rate" of listed Columbia Basin stocks. The model estimates that, if the predation were eliminated it would yield a maximum potential improvement in population growth rate of from 0.2 to 2.3 percent. A 50 percent reduction in predation is estimated to produce a 0.1 to 1 percent improvement.

"For comparative purposes, changes called for in NMFS' Biological Opinion on operation of the hydropower system (FCRPS), to improve passage for both adults and juveniles are anticipated to increase population growth rates by approximately 1-2 percent for the Snake River spring/summer chinook salmon ESU and nearly 5 percent for the Snake River fall-run chinook salmon ESU (NMFS 2000)," the report says.

The NMFS draft report also says, in summary:
-- Human activities have contributed to salmon and steelhead declines,
-- Predation by terns living on manmade islands in the estuary is a relatively new source of juvenile salmonid mortality,
-- The effect of tern predation varies between years and among salmonid species and is greatest on steelhead and smallest on wild yearling chinook,
-- Moving terns to habitat that offers a greater diversity of prey can reduce the impact on salmonids, and
-- Returning the estuary to a more 'normative' process is likely to allow for a more diverse diet for terns, reduce predation on salmonids and provide better habitat for a wide variety of animals as well as juvenile salmonids.

The draft "Status Assessment and Conservation Recommendations for the Caspian Tern (Sterna Caspia) in North America" was released on April 25. Authors of the preliminary document were W. David Shuford of the Point Reyes Bird Observatory in Stinson Beach, Calif., and David P. Craig of Willamette University's department of biology.

Tern populations, for the most part, have increased across much of the nation, according to the report. The Caspian tern "still occupies most of its former range and has expanded slightly into new areas."

"Continent-wide population increases were fueled initially be the reduction of elimination of some historical pressures (e.g. hunting for the millinery trade) but more recently by changed in breeding habitat and prey resources," the draft says. "In coastal areas, increases are strongly associated with use of artificial habitat for nesting."

That boon may also be a bane in places such as the Columbia River estuary. Islands created from navigation channel dredging spoils became havens for terns. The NMFS report says that no terns had been nesting in the estuary prior to 1984, when 1,000 pairs settled onto newly formed East Sand Island. The birds had "apparently moved from Willapa Bay" to the north of the estuary.

The colony moved upriver to Rice Island in 1987 and grew to an estimated 10,000 pairs. The management plan in place for the past two years resulted in the birds being relocated back to East Sand.

The draft tern report points out that the Columbia estuary tern colony now represents two-thirds of the Pacific Coast population and one-quarter of the North American population. That bunching of the population at one site leaves it "more vulnerable to stochastic events such as disease outbreaks, severe storms, disruption by predators or human disturbance and oil spills."

Winegrad said that the tern population draft report "seems to be a scholarly and a fair and accurate assessment." He noted that the report cites data indicating that the Columbia estuary population appears to have leveled off, or be in decline, over the past two years. The terns, Winegrad said, have been essentially shoehorned onto the only habitat available to them. Historic inland habitat, and along the Washington coast, has been destroyed.

"The terns just don't have any place to turn to," he said. He faulted state and federal officials for repeating a goal of finding alternative habitat for the terns but failing to come up with any.

"It's been four years and they still don't have a square inch" of new habitat," Winegrad said. "It's more political than it is biological." He said the exaggerated impact of tern predation on salmon has made the pursuit of alternative habitat more difficult. Local and tribal entities have headed off attempts to establish habitat along the Washington coast.

The draft tern population assessment urges conservation efforts on "multiple fronts:"
-- monitoring tern populations;
-- resolving management conflicts with other species by addressing root causes;
-- reducing risks to the tern population by distributing breeding colonies among a greater number of sites;
-- filling gaps in knowledge of biology and threats on migration and the wintering grounds, and
-- educating the public about the value of colonial waterbirds and possible effects of human actions on Caspian terns.

As part of the peer review process, copies of draft reports were provided to a list of scientists chosen by the plaintiffs in the case. The National Audubon Society, Defenders of Wildlife, Seattle Audubon Society and American Bird Conservancy filed the lawsuit early in 2000 challenging the scientific basis for the plan and the agencies' failure to complete an adequate environmental impact study. The groups said the tern management developed by the federal, state and tribal entities did not take into account the long-term welfare of the birds.

The agreement stipulates that the reviewers had no less than 60 days to submit written comments on the draft reports, which would be submitted individually by each reviewer and considered by the defendants before finalizing the reports.

The settlement agreement charges the USFWS, in cooperation with NMFS and the Corps, with initiating National Environmental Policy Act scoping in April 2003 on Caspian tern management in the Columbia River estuary through publication of a notice in the Federal Register.

A draft environmental impact statement is to be completed and published by Oct. 1, 2004, and the final EIS and record of decision must be completed and published by Feb 28, 2005. The USFWS must initiate implementation of the alternative selected in the ROD by March 2005.

"In addition to those issues required to be considered, discussed, and evaluated under NEPA, the EIS shall include: (1) an evaluation of a no-action alternative (no management) wherein the biological necessity for any management will be examined; (2) an evaluation of an alternative that retains Caspian Tern habitat on East Sand Island and into the future including improving that habitat by placing sand nesting substrate on East Sand Island; and (3) a discussion of Caspian Tern predation in context with other factors influencing ESA listed salmonid recovery," according to the agreement.

Link information:
NMFS report: http://www.nwr.noaa.gov/1habcon/habweb/default2.html
USFWS report: http://migratorybirds.pacific.fws.gov/reports.htm

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4. SCIENCE PANEL RANKS 'INNOVATIVE' PROJECT PROPOSALS

By Barry Espenson

The Independent Scientific Review Panel says that as many as 17 "innovative" project proposals met criteria for funding under the Northwest Power Planning Council fish and wildlife program, with five of the projects standing above the rest.

Thirty-seven proposals were originally submitted in answer to the fiscal year 2002 solicitation requesting a total of about $6.5 million. The innovative project category has been funded at a level of $2 million per year in each of the past two years. The Bonneville Power Administration, which funds the program, again allocated up to $2 million for innovative projects. The Council however, this year reduced from $400,000 to $200,000 the cap for any individual project funding through the innovative category.

The Council has defined innovative projects as those that "rely primarily on a method or technology that (1) has not previously been used in a fish or wildlife projects in the Pacific Northwest, or (2) although used in other projects, has not previously been used in an application of this kind."

The Council will weigh the advice of the ISAB before making recommendations to BPA about which projects should be given funding. The submittals are almost exclusively research projects coming from universities, federal and private laboratories and research facilities, tribal entities, conservation districts and others.

"The spirit of the category is to bring in these types of research" projects, said Gustavo Bisbal, NWPPC senior policy and science analyst. The category is not for ongoing types of projects but rather for pilot type projects aimed at answering specific questions. Projects can only be funded once in the category.

The intent is to prompt "fresh ideas and a quick determination if they will work or not," Bisbal said. A public comment period on the projects continues through June 28. The Council would likely make a funding recommendation during its August meeting.

In its review published May 24 the ISRP said that 17 proposals met the innovative criteria, described scientifically sound techniques, and offered potential benefits to fish and wildlife. The top five proposals, and especially the top three, stood-out as proposals that are high priority meriting immediate funding.

The ISRP's favored projects focused on answering questions that the scientists said would almost certainly benefit fish and wildlife recovery efforts.

ESSA Technologies Ltd. proposes to "compile and compare data from habitat restoration projects in multiple watersheds to enhance the rate of learning about effects of restoration actions on fish populations, optimize the design of future restoration programs and improve monitoring." The cost would be $199,764. The ISRP called the project "innovative and needed."

"The ISRP recommends funding this cost-effective, innovative pilot project to provide an independent check on evaluation of watershed restoration procedures. We agree with the proponents that '…an exploration of multi-watershed approaches to testing tributary restoration hypotheses, using both actual data from existing projects and potential data from future projects, can act as a catalyst to improving Columbia Basin tributary restoration programs…,' " the scientists wrote.

The second of the three projects that tied for the ISRP's No. 1 ranking would "evaluate the relationships among river discharge, hyporheic zone characteristics, and egg pocket water temperature in Snake River fall chinook salmon spawning areas; evaluate the potential for improving Snake River fall chinook salmon smolt survival." The $196,299 Pacific Northwest National Laboratory proposal, "could provide very substantial gains for Snake River fall chinook and the water budget," the ISRP wrote.

"Summer flow augmentation to benefit downstream migrating fall chinook has been a contentious issue within the basin. The investigators hypothesize that extending the period of stable flows below the Hell's Canyon complex (now 10 to 20 days in December) well into the egg incubation period could provide more favorable conditions for incubation and decrease the time required for the eggs to hatch," the ISRP said.

"Earlier emergence would make it possible for juvenile fall chinook to migrate downstream sooner than they currently do and thus enter the Snake River reservoirs earlier in the summer, when water temperatures and stream flows are more beneficial for survival. This change in migration timing could reduce the need for summer flow augmentation. A clear and reasonable line of logic backs the proposal," according to the ISRP report.

The third top-ranked project would "identify population structure of indigenous chinook salmon in the Middle Fork Salmon River from patterns of genetic variation indicated by microsatellite DNA markers and spatio-temporal patterns of spawning habitat utilization." The $199,957 project would be carried out by the USDA Forest Service Rocky Mountain Research Station.

"This excellent proposal offers an innovative use of recent developments in analysis of molecular genetic markers (microsatellites) to define spatial and temporal patterns of genetic variability among spawning aggregations of chinook salmon," the ISRP wrote.

The proposals ranked from 6 to 12 by the ISRP also offered potentially valuable contributions to the NWPPC's fish and wildlife program, the ISRP wrote. Those ranked from 13 to 17 met the review criteria but did not demonstrate as strong a potential to provide significant benefits as the top 12.

The ISRP did not rank the other 20 proposals submitted.

"For a variety of reasons, these proposals did not provide adequate justification for funding under the innovative solicitation. A few of these proposals were not innovative but offered approaches that could benefit the fish and wildlife program. Several others were innovative but were not technically sound or did not demonstrate benefits to fish and wildlife. Most were neither innovative nor technically sound," the ISRP wrote.

Five of the top ten ranked proposals had been submitted and reviewed in previous processes, but were subsequently improved, the ISRP said.

Several ISRP and Peer Review Group reviewers evaluated each proposal and provided comments and rough ranks for group discussion.

"Determining whether a proposal is 'innovative' can be difficult; consequently, the ISRP reviewed all the proposals for their technical merit and potential to contribute benefits to fish and wildlife. At the meeting, the ISRP discussed each proposal and reached consensus recommendations and rankings," the report said.

Link information:
NWPPC: http://www.nwcouncil.org/

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5. HYDRO OPERATIONS IMPROVE FOR SALMON

By Mike O'Bryant

With rain, warmer weather and more snow melt, juvenile salmon have been getting the amount of water they need to pass Columbia and Snake river dams. After a delayed spring snow melt, river levels began rising two weeks ago and have remained at or above target flow levels recommended in the National Marine Fisheries Service 2000 biological opinion.

Salmon managers worried that low water has been delaying juvenile salmon and steelhead migrations down both rivers, asked dam operators at the May 22 Technical Management Team meeting to meet BiOp flow targets, even if the operations require drafting Grand Coulee Dam reservoir below an elevation of 1,237 feet, which the Bureau of Reclamation agreed to a week earlier. Flow targets are 97,000 cubic feet per second at Lower Granite Dam on the Snake River and 246 kcfs at McNary Dam on the Columbia River.

Salmon managers also asked in a systems operation request (SOR) that the U.S. Army Corps of Engineers hold outflow levels at Dworshak Dam on the North Fork of the Clearwater River at 10 kcfs, instead of dropping outflows to the project minimum of 1.5 kcfs, and asked Idaho Power to pass inflow through Brownlee Reservoir.

"We're still concerned about the amount of (juveniles passing through the system)," said Ron Boyce of the Oregon Department of Fish and Wildlife. "We're getting less than half the chinook and steelhead through the Snake River and that's the basis for this SOR."

On May 22, passage estimates at Lower Granite Dam for wild chinook and steelhead juveniles were below the 10-year average, while passage of adult chinook at Bonneville Dam on the Columbia River were above the 10-year average. Although the adults have been running late due to cooler water temperature, Boyce said the run should be about 309,000 fish, which is close to the pre-season forecast of 330,000 fish.

(Next year's adult return is likely to be lower, according to Chris Ross of NMFS, who said chinook jack returns are 0.1 percent, whereas the 10-year average is 6.1 percent. However, that is relative to a very large run, which is 131 percent of the 10-year average.)

The Corps agreed to drop outflow at Dworshak Dam from the 14 kcfs it had been at for several weeks to 10 kcfs on May 24 and held that level until May 27. No longer needing Dworshak reservoir water to supplement flows in the lower Snake River, but needing to begin refill at the project, the Corps dropped outflows from the dam to 1.5 kcfs. Due to inflows and a self-imposed requirement to keep reservoir fluctuations to a minimum, Idaho Power has been passing inflow through Brownlee Dam.

Weekly average flows through Lower Granite Dam (May 20 to 27) were 98.2 kcfs, which exceed the BiOp target flow of 97 kcfs, and flows on May 29 were 110 kcfs, "so it appears the freshet is here," said the Corps' Rudd Turner. In addition, he said lower Columbia River flows are about 300 kcfs and all storage reservoirs are refilling. Grand Coulee reservoir (Lake Roosevelt) is at 1,256 feet, less than 35 feet from full, and filling at the rate of one to two feet per day.

Link information:
Technical Management Team: www.nwd-wc.usace.army.mil/TMT/index.html

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6. BPA CONCERNED ABOUT FINANCES, RESERVES

The head of the Bonneville Power Administration warned last week that the West Coast energy crisis in 2001 and continued economic recession are threatening the agency's financial soundness.

BPA Administrator Steve Wright said that despite a 46 percent wholesale rate increase, the non-profit agency expects to lose money this year for the second year in a row and anticipates that its once-healthy reserve funds will be decimated.

Reserves are forecast to fall to $100 million by Sept. 30, leaving Bonneville with "not much of a cushion" to be able to withstand another drought and still make its annual Treasury payment, Wright said in a session on May 22 with Northwest newspaper reporters in Washington, D.C. "It's a fundamental concern I have," he said.

Last year, because of near-record drought and Westwide electricity shortages and high prices, Bonneville declared an emergency, bought down customer load and took a one-time Treasury credit of over $500 million for past fish and wildlife mitigation costs. This spring, stream flows have returned to average and BPA has surplus electricity to sell but the economic downturn has reduced prices and demand, Wright said.

Wright indicated he will not seek a higher rate increase this fall to build up reserve funds, which once topped $700 million. But he said the agency will need to address the problem during the coming two years. First, BPA plans to develop possible solutions then seek public and stakeholder comment and proposals before deciding. "It needs to be a regional decision-making process," he said.

Jeff Stier, BPA vice president for federal relations, said the agency has also been cutting costs and has saved $100 million this year. No employees have been laid off but money has been saved through unfilled vacancies, travel and training limitations and lower fuel costs at power plants.

Wright said this fall's rate proposal is still expected to be in the same range as last year's, 42 percent to 46 percent above baseline.

Stier said BPA's quest for a $2.1 billion increase in its federal borrowing authority will not affect its rates or finances. Those funds would be used to expand and improve the transmission system, and would be repaid through transmission fees.

Wright was making one of his periodic visits to Washington to meet with administration officials and Northwest members of Congress. He also responded to an inquiry to the Federal Energy Regulatory Commission about whether BPA engaged in any of the questionable electricity trading practices used by Enron Corp. in the West Coast market.

"These are not practices we engaged in," Wright said. He said BPA officials were suspicious because electricity prices surged and energy was moving out of California, but they did not have any knowledge of Enron's schemes. Those included overscheduling transmission in California to increase congestion and selling power out of state to avoid a price cap and then reselling to California at higher rates.

Although BPA's own energy traders were under great pressure last year to make money, Wright said he was "happy to say that nothing turned up" during an investigation over the last couple of weeks in response to FERC's inquiry.

In a matter related to both Enron's and BPA's finances, Wright said agency attorneys were still trying to determine whether it could break a high priced long-term purchase contract with the energy company. "I'm not ready to call that one yet," he said. "We're looking at all options, particularly in light of recent revelations."

Cancellation of the $700 million four-year contract would save Bonneville a total of about $250 million at current electricity prices, Wright said. The savings of roughly $60 million per year would be the equivalent of a 4 percent rate reduction.

The Enron deal was signed last year when West Coast electricity prices were inflated by drought, shortages and problems in California's deregulated utility system. Most of BPA's other long-term contracts are low-priced. Shortages were alleviated last year mostly by buying down its demand load from aluminum companies and other major customers, Wright said.

Wright met privately with Sens. Maria Cantwell, D-Wash., and Ron Wyden, D-Ore., both of whom have urged FERC to void contracts between Enron and Northwest utilities and to order energy suppliers to make refunds based on the disclosures of market manipulation. The BPA boss said he would not comment on details of his discussions with the senators but that "in general, everybody would like us to look at all our options."

He acknowledged that one consideration will be BPA's past legal position that FERC does not have any authority over its contracts. "It's an open question for me" as to whether FERC has jurisdiction, Wright said.

Wright said he does not have an opinion on various options, including unilateral action by BPA, petitioning FERC or going to court. He said he hoped to get a sense from attorneys soon of what options are realistic. BPA previously has discussed the contract issue with Enron officials but is not currently engaged in discussions with the company, he said.

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7. FALL CHINOOK FISHING HOPES TEMPERED BY COHO CONCERNS

State officials say the expected strong return of chinook salmon headed back to the Columbia River this season should make for some exceptional fishing along Washington's Pacific coast as long as anglers don't catch too many wild coho salmon.

The early chinook fishery opened May 25 in Marine Areas 1 through 4, which is essentially from the Columbia River to Washington's Neah Bay area. The fishery is open seven days a week through June 16, or until the season limit of 20,000 chinook has been taken. Anglers can keep two chinook a day, with a minimum size of 24 inches.

In sharp contrast to the anticipated chinook bounty is a projected weak return of Columbia River coho salmon. Biologists are forecasting a return of about 360,000 Columbia River coho this year, compared to last year's forecast return of about 1.5 million.

"Our over-arching conservation concern this year is for coho stocks returning to the Columbia River and Oregon's coastal streams," said Jeff Koenings, WDFW director.

"We will carefully monitor the chinook fishery to insure we are not exceeding our coho bycatch estimates," he said. "Exceeding those estimates could mean a premature closure of the chinook fishery whether or not there are chinook still available for harvest."

Pre-season forecasts indicated a return of about 675,000 chinook returning to the Columbia River. That is nearly double last year's pre-season forecast of 365,000 chinook.

"This is a tremendous sport chinook fishing opportunity, the likes of which we haven't seen on our coast for at least two decades," Koenings said.

Anglers who hook coho should treat the fish with care. Keep the fish in the water, and avoid netting or boating the fish. Proper use of a de-hooking device can also reduce mortality.

Salmon fishing opens again on June 30 in Marine Area 2, and on July 7 in Marine Areas, 1, 3 and 4. Anglers should check the 2002/2003 "Sport Fishing in Washington" sport fishing rules pamphlet for additional season and catch limit information. The pamphlet is available on-line at http:www.wa.gov/wdfw.

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8. DRAFT NMFS BIOP FOR UMATILLA IN 'REVIEW MODE'

By Wil Phinney

Two months after its release, officials still are reluctant to discuss a National Marine Fisheries Service draft biological opinion that says continued operation of the Bureau of Reclamation's Umatilla Basin Project would jeopardize Mid-Columbia River steelhead.

Recovery efforts in the Umatilla River in eastern Oregon have resulted over the last few years in the return of thousands of spring chinook and coho salmon, which had been extinct for more than 70 years after the river was dammed and diverted early in the 20th Century to supply water for federal irrigation projects.

NMFS concluded in the April draft Bi-Op, however, that the proposed operation of the 20-year-old Umatilla Basin Project "is likely to jeopardize the continued existence" of MCR steelhead and to "adversely modify its designated critical habitat." Because the status of the species is poor, "these effects rise to the level of jeopardy," the draft Bi-Op states.

The major problems to be addressed by the "Reasonable and Prudent Alternative" in the draft BiOp include stream flow in the lower Umatilla River during July and August; stream-flow temperatures in the lower Umatilla River during July, August and September; stream flow in lower McKay Creek during November through March; the long-term security of federal water for the survival and recovery of listed steelhead; and habitat improvements in the lower Umatilla River to support rearing and migration life stages.

Local river users are worried that the BiOp could "blow up" the third phase of the Umatilla Basin Project. The Confederated Tribes of the Umatilla Indian Reservation and Westland Irrigation District near Hermiston in March reached accord to seek federal funding for a feasibility study on the third and final phase of the bucket-for-bucket exchange program, which provides Columbia River water for irrigators and leaves flows in the Umatilla River for fish.

Following a meeting Wednesday between the federal agencies, the Bureau of Reclamation intends to provide additional information to be considered by NMFS in subsequent analyses.

"What we have is a draft," said Rich Rigby in Reclamation's regional office in Boise. "Every draft gets to be completed and changed in the process."

Dr. Kate Vandemoer, the NMFS scientist in charge of the draft BiOp, said no decisions have been made as to the course of action for either Reclamation or NMFS.

"I would still characterize everyone as in 'review mode,' with perhaps a little more discussion," Vandemoer said Thursday.

Meanwhile, comments regarding the draft BiOp have been submitted to NMFS from the Umatilla Tribes and from Westland Irrigation District.

Mike Wick, manager of Westland Irrigation District, did not return phone or e-mail messages, and Vandemoer said NMFS could not provide Westland's comments.

The tribes are "generally encouraged" by the analysis, but say the draft BiOp "does not adequately acknowledge the benefits" of the Umatilla Basin Project to MCR steelhead in the Umatilla River.

"While Reclamation's (1905) Umatilla Project has contributed to the elimination of CTUIR's salmon fishery and the depletion of the MCR steelhead population in the Umatilla River, the (1980s) Umatilla Basin Project has restored needed fish flows in the Umatilla River, re-established chinook and coho salmon populations and benefited MRC steelhead," the tribes' Fish and Wildlife Committee and Tribal Water Committee said in a nine-page letter to Robert Lohn, director for NMFS' Pacific Northwest Region.

The tribes support relying on McKay Reservoir as a potential solution, particularly in addressing high temperature issues in the lower stretch of the river.

"It seems that using McKay is the best way to help fish and not hammer irrigators too hard," said Harold Shepherd, the tribes' Umatilla Basin policy analyst. "Using the stored allocation could spread the pain evenly among all users of McKay, which includes water for fish."

The draft BiOp would require Reclamation to use its discretionary authority to allocate storage in McKay Reservoir to insure a minimum flow in the Umatilla River of 150 cfs.

That requirement recognizes "that even with the completion of the water exchange under phases one and two of the Umatilla Basin Project, stream flow enhancement is still necessary for fish needs in the Umatilla River," the tribal committees said. "As a result, we fully support the reversal of current improper allocation of flood storage space in McKay Reservoir and re-allocating storage in order to maintain flows for fish on a year-round basis."

The draft Bi-Op says NMFS is confident that the RPA can be implemented with the continued "normal deliver of water for irrigation uses." However, the BiOp also identifies irrigation district temporary water service contracts as impacting listed species. Reclamation is currently in the process of re-issuing temporary water service contracts for the 2002 irrigation season.

The RPA seeks to assure there be "zero net impact" from Reclamation's decision to supply water to the Westland temporary water service contract and for lands to be included in a boundary adjustment for two other Hermiston-area irrigation districts. The RPA requires that the temporary water service contracts provide replacement flows of 10,000 acres feet of lost return flow resulting from the expansion of the irrigated land base. Over 8,800 acre feet of this water is already made available as mitigation flows, so the RPA requests 1,200 acre feet more of return flow placement. The water for replacement flows, according to the draft Bi-Op, may be derived from McKay contracted or reserved storage, from foregoing live flow diversions with relatively junior priority dates, or through use of the flexibility within the exchange program.

The RPA also requires a report on the feasibility of increasing the capacity of McKay Reservoir and of creating passage at the reservoir for listed steelhead, or other options for increasing steelhead access to upper McKay Creek.

"The dam blocks MCR steelhead and other anadromous fish from accessing upper McKay Creek, which, prior to construction of the dam, served as important spawning and rearing habitat," the tribes said in their comments.

Reclamation and NMFS officials said "change is built into the draft opinion" and that the process will proceed. Tribal leaders said, too, they would likely submit more comments as the process continues.

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9. SCIENTISTS ASK NORTON TO RECONSIDER WOLF RECLASSIFICATION

By Wil Phinney

Forty-eight scientists have asked Secretary of Interior Gale Norton to terminate the reclassification of the gray wolf under the federal Endangered Species Act.

The scientists on Wednesday sent a letter to Norton opposing a draft rule by U.S. Fish and Wildlife that "overlooks or abrogates scientific and legal principles under the ESA to restore gray wolf populations to 'significant gaps' within the species' historic range that are currently unoccupied, but where restoration remains feasible."

Norton's proposal, according to the conservation groups, sets the stage to hand off protection of the species to several state governments, including Idaho, where the Legislature recently voted for eradication of wolves, and Minnesota, which as reinstituted a bounty on wolves.

In Oregon, several speakers are scheduled to address wolf management at the June 6 meeting of the Oregon Fish and Wildlife Commission. Invited speakers include Gary Power, wolf-mountain lion predation study in Idaho; Grant Simonds, Idaho Outfitters and Guides Association; Al Elkins, Oregon Hunters' Association; Eldon Deardorff, Eastern Oregon Outfitters and Guides; Sen. Laird Noh, Kimberly, Idaho; Carolyn Sime, Montana Fish, Wildlife and Parks; Bill Cook, Oregon Department of Justice; Mack Birkmaier, Oregon Cattlemen's Association; Nancy Weiss, Defenders of Wildlife; Robert Cope, Lemhi County (Idaho) commissioner and veterinarian; and Carl Scheeler, wildlife program manager for the Confederated Tribes of the Umatilla Indian Reservation.

In their letter to Norton, the scientists acknowledged "unquestionable progress" by FSW toward wolf recovery in the lower 48 states, but said the proposed rule contains major flaws that depart significantly from the letter and spirit of the ESA, agency polices and regulations and principles of conservation biology.

"A final rule based on the draft will result in substantial litigation, diminish the significant process with wolf recovery in the Great Lakes region and the northern Rockies, imply to many observers that the rule is motivated by politics rather than science, and undermine the credibility of the Endangered Species Act and the Service's ability to implement the act in an honest and objective manner," the scientists' letter said.

The scientists included wildlife biologists, ecologists, conservation biologists, population biologists, sociologists and environmental scientists.

Reaction to the letter from conservation groups was expectedly positive.

"Secretary Norton wants to back away from the job of wolf recovery before the job's finished," said Dr. Mark Shaffer, senior vice president for programs at Defenders of Wildlife. "No one is more anxious to see successful wolf recovery than the signers of this letter and the conservation groups that have invested years in the project, but for FWS to pull the plug prematurely will undo the progress we've made and delay true recovery, perhaps for decades."

Mike Phillips, executive director of the Turner Endangered Species Fund, said "Scientists have concluded that top predators, notably the gray wolf, are absolutely essential for long-term maintenance of the balance of nature and therefore the long-term maintenance of biodiversity."

The FWS proposal is coming under fire from all sides, including a letter from fish and wildlife agencies in five states expressing concerns about the draft rule, according to a news release from Defenders of Wildlife, the Turner Endangered Species Fund and the Wildlands Project.

"Politics rather than science seems to be driving the department on this issue, but it seems to be driving them straight into a brick wall," said Jen Callahan, Rocky Mountain director of the Wildlands Project.

The conservation groups' email news release, forwarded in a mass-mailing by Jerry Cordova of the U.S. Fish and Wildlife Services to parties interested in wolf information, prompted response from Sharon Beck, past president of the Oregon Cattlemen's Association.

Beck questioned the credibility of some of the scientists as well as the Wildlands Project, which, according to the news release, has a goal of protecting and restoring the "natural heritage of North America through the establishment of a connected system of wildlands."

Cordova later apologized for providing "information that I thought pertinent for the broader wolf information group [that] may not have been appropriate." To provide balance, Cordova included Beck's comments to the reclassification provided more than a year ago to the FWS.

In his defense, Karen Haines, a wildlife biologist with the Malheur National Forest, thanked Cordova for providing the information in the mass mailing.

"No matter what the values and beliefs of the scientists that issued the letter are or the values and beliefs of anyone else are, information given to the press is important to know in case we get questions regarding it," Haines said in an e-mail reply to the wolf information list.

In her comments on the reclassification last year, Beck said the attempt to downlist the wolf is designed to elevate the debate about wolves in Oregon in preparation for their de facto introduction.

Beck stated: "You have repeatedly stated 'no introduction of wolves is planned for Oregon.' The Oregon Department of Fish and Wildlife has repeatedly stated that Oregon doesn't have an adequate prey base for wolves without causing great conflict. Our state legislators and county government bodies have all passed policy that request removal of wolves coming to Oregon from the experimental populations. I do not believe there is anywhere in the lower 48 states where wolves presently reside that is free of conflict and yet you persistently end each statement with 'but they are going to come anyway and we can't really stop them.' And now you are saying 'We're pretty sure the wolf is already here' and 'we cannot afford to round up and return every wolf that finds its way to Oregon' and 'we will not do anything about a wolf in Oregon unless we first verify that it has killed livestock.' You have also established that our working dogs are not livestock so we can only assume our workin!
g horses and pets aren't either and thus expendable like you have treated them in other states.

"We know that wolves will kill our wildlife herds, our livestock and our pets. We know there is risk for our children. We are left on our own to take care of our own. And trust me we will. A reporter recently asked me if I intended to take the law in own hands. My answer is that indeed I do and that law provides that I have the right to protect my life, my family and my property. I consider that to be not only our right, it is our duty.

"So do not tell me that Defenders of Wildlife will pay me for my cattle killed by wolves, that you will destroy wolves if you can establish that they habitually kill cattle, that you will issue me a limited number of rubber bullets to shoot the wolves, that you will send our wolves to boot camp at Ted Turner's Montana ranch for attitude adjusting shock treatments; just take them back to Idaho where you introduced them and where you agreed to keep them."

The bottom line, Beck said, is this:

"We do not have wolves in Oregon. We can't have wolves in Oregon without conflict. We don't like conflict in Oregon. Therefore we do not want wolves in Oregon."

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10. AGENCIES LOOK AT 'BIG-TICKET' FISH PASSAGE PROJECTS

By Barry Espenson

The multi-agency group charged with setting priorities for fish passage improvement projects at Columbia-Snake mainstem dams began last week to ponder the order in which so-called "big ticket" capital projects should be implemented over the next eight years.

That time span runs to the end of the National Marine Fisheries Service's 10-year Federal Columbia River Power System biological opinion. The BiOp issued in December 2000 details measures that the agency feels must be taken to improve the survival of 12 salmon and steelhead stocks listed under the Endangered Species Act.

The System Configuration Team prioritizes research and fish passage improvement projects that are, for the most part, implemented under the guidance of the U.S. Army Corps of Engineers at the eight lower Columbia and Snake river federal dams. State and tribal fish and wildlife officials, as well as representatives of the U.S. Fish and Wildlife Service and Bonneville Power Administration, also take part in the SCT process. The SCT is part of the Regional Forum created via the 1995 FCRPS BiOp and continued under the new strategy.

The work at the dams is funded through congressional appropriations that are ultimately reimbursed to U.S. Treasury by the BPA. The appropriations vary depending on the fiscal mood of Congress but have been in the $70 million to $80 million range.

The fiscal year 2002 appropriation is $81 million, though about $13 million is being held back through a Corps administrative buffer called savings and slippage. With an eye toward implementing more of the measures called for in the 2000 BiOp, the Bush administration has requested a $98 million budget for fiscal 2003.

A spreadsheet produced by the Corps' John Kranda for last week's SCT meeting listed 80 projects now under consideration. Completing them all by the end of 2010 would cost more than $900 million at the most recent cost estimates. Those estimates change regularly as designs are furthered. Projects are added to the list, and others fall off, through time as research identifies what types of measures work best to improve passage survival of the fish.

"It's all speculative. There's a lot of decisions to be made," Kranda said this week. An example, he said is $39 million budget item aimed at ultimately reducing or eliminating problems with adult salmon and steelhead fallback at Bonneville Dam. Studies are planned to better pinpoint the cause of the fallback and recommend a cure, so the current plan, and cost estimate could be altered drastically.

The list includes 10 projects that would cost more than $40 million to complete -- from the beginning of design through construction. Three projects -- construction of surface bypass technology at The Dalles and McNary dams and a new bypass system at Bonneville Dam's first powerhouse -- each are estimated to cost more than $75 million.

And while not all of the expense for those projects are incurred in a single year, it will likely be necessary to stagger the start of the projects so that one or two projects don't take up an entire year's appropriation.

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11. HELLS CANYON RELICENSING HITS IDACORP SHAREHOLDER MEETING

By Mike O'Bryant

Environmental groups and an asset management firm petitioned IdaCorp's shareholders at the company's annual shareholder meeting in mid-May to pass a resolution that would force the utility to provide hydro relicensing information about the company's Hells Canyon complex of three hydroelectric dams on the Snake River.

The resolution, which also called for IdaCorp to determine the potential economic impacts to the company of breaching four lower Snake River dams, garnered 34 percent of the available votes at the meeting, which is not enough to force the utility to cough up the information. Even so, the petitioners are claiming victory.

"This vote is a huge victory for shareholders and the environment," said Lisa Leff, vice president of Trillium Asset Management, which specializes in socially responsible asset management and holds about $4.3 million in IdaCorp stock for clients. "The level of investor support far exceeds our expectations. In our experience, any shareholder vote over 10 percent indicates investor unrest. Today, over one third of voting stockholders have said that IdaCorp cannot continue to withhold information about the Hells Canyon Complex relicensing."

Leff added that the complex of dams affects the environment, endangered species and IdaCorp's bottom line, and shareholders need to know the economic costs of relicensing. She said that Idaho Power will have to mitigate for the impacts the dams have on endangered species -- such as providing fish passage or water quality control structures

-- as a condition of renewing its license and it should report the predicted costs of an array of mitigation options to shareholders.

IdaCorp's Jeff Beaman called the vote more of a moral victory for the groups, but said the company still will not provide immediately the periodic reports the groups requested. The utility expects to include in September much of that information in the draft application it is preparing for the Federal Energy Regulatory Commission. That's when the information will become part of the public record, he said.

"On one end of the spectrum are groups who want to run the dams for power generation only: on the other end of the spectrum are those who want the projects to bear total and complete responsibility for environmental impacts," Beaman said. "It's our job to balance those views."

In the mid-1990s, Idaho Power invited stakeholders, including the environmental groups to participate in a collaborative relicensing process. However, a coalition of environmental groups (American Rivers, Trout Unlimited, Idaho Rivers United and the Hells Canyon Preservation Council), chose to withdraw from the talks in May 2001 after the utility said it wouldn't discuss issues relevant to a pending biological opinion. It was consulting on the BiOp jointly with FERC and the National Marine Fisheries Service. The BiOp, which still is pending, would address the impacts of the existing operations of the three dams on salmon and steelhead species listed under the federal Endangered Species Act.

Sara Denniston Eddie of Idaho Rivers United said the utility could avoid litigation and more costly mitigation measures if it would begin to disclose the information now.

However, Beaman said there is a fundamental difference between the parties and Idaho Power about the timing of disclosing important information, but that the "doors are always open" for the groups to come back to the collaborative process. The risk of releasing information too early, he said, is that the groups could pick out information and use it against the utility before it had been finalized. It presented many of those findings at a collaborative workshop early in May.

Although Idaho Power doesn't own the four federal lower Snake River dams, their removal could affect what Idaho Power would have to do at its Hells Canyon dams. If their removal benefits listed fish, Idaho Power may need to complete fewer mitigation measures, the groups said. However, if they are not removed, that could mean even more costly mitigation measures for the utility.

"The government's decision whether to remove the lower Snake dams has a direct impact on the Hells Canyon Complex and IdaCorp," said Leff. "And if removal of the federal Snake River dams would benefit the company financially, it's critical that IdaCorp disclose that to its shareholders."

That information will not be a part of the license application, according to Beaman.

Link information:
Idaho Power: www.idahopower.com
American Rivers: www.amrivers.org
Idaho Rivers United: www.idahorivers.org
Trillium Asset Management: www.trilliuminvest.com

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12. WATER RIGHTS SWAPPED TO BOOST RESORT, SAFEGUARD FISH

The Washington Department of Ecology last week approved a package of water rights that will support the development of Trendwest's Mountain Star resort and adjacent properties near Cle Elum.

In addition, the resort company has set aside water in several tributaries to enhance stream flows to benefit fish and other aquatic resources, and to offset the effects to the Yakima River of water consumed at the proposed resort properties.

"This is a particularly creative approach to finding water for a new development while also protecting existing water rights and stream flows," said Bob Barwin, the state agency's water manager in Yakima. "It's been a long road, both for Trendwest and the community, but these decisions provide the certainty needed in a region where water is a precious commodity."

In its effort to secure water for the project, Trendwest Resorts, Inc., acquired a number of water rights within the Yakima River Basin. The package includes a large set of water rights that had historically been diverted near Ellensburg. Before the water could be used at the resort, the company needed authorization to withdraw the water at Cle Elum. It also needed to change the rights from seasonal irrigation to year-round uses, including domestic, municipal and recreation.

This spring, the newly-formed Kittitas County Conservancy Board endorsed the transfer of the water rights, known as the Pautzke Bait Company water rights, from Ellensburg to the resort and adjacent properties near Cle Elum. Ecology has now approved the board's decision with some conditions.

The resort will have access immediately to about half of the water authorized in the decision. The rest of the water will be available after the resort company prepares an acceptable mechanism for monitoring the water rights placed into trust. The company also needs to show how it would manage water during years when water diversions are restricted by the U.S Bureau of Reclamation.

Ecology also has authorized transferring tributary water to the Yakima Basin Trust Water Program from Big Creek and the Teanaway River. The trust water rights will enhance stream flows in the tributaries and can be used mitigate the effects on Yakima River water users for water consumed at the resort that is more than the historic consumptive use at the Pautzke properties. Additional trust water-right decisions are pending on applications for water from Swauk and First creeks.

Link information:
WDOE: http://www.ecy.wa.gov

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13. IDFG RESEARCH AIMS FOR MORE 'CATCHABLE' RAINBOW TROUT

During 2001, anglers in south-central and southeast Idaho had the chance to participate in a new fisheries research project designed to make hatchery rainbow trout more "catchable " as well as $50 in prize money. The focus of the program shifts this year to the southwest part of the state.

In 1998, about 2,750 newly hatched rainbow trout from Hayspur Fish Hatchery near Picabo were placed into raceways. These fish were raised for a year and then marked with individually numbered tags. From June through September 1999, the trout were caught and released repeatedly, while biologists recorded the number of times each fish was caught. Fish caught two or more times were kept for breeding purposes. Fish that were caught only once or not at all were removed from the breeding population.

The offspring of the highly catchable rainbow trout were stocked in waters across southwestern Idaho before or shortly after stream fishing season opened on May 25. Sixteen waters will be stocked and each will receive equal numbers of highly "catchable" and normal rainbow trout. Prior to stocking, a small, numbered metal band will be affixed to the lower jaw of each fish. Lucky anglers are asked to return the tag along with the angler's name, address, and phone number as well as the location and date the fish was caught to: Nampa Research Office, IDFG, 1414 E. Locust Lane, Nampa, ID, 83686.

By supplying the information, anglers will help Idaho Fish and Game researchers Dan Schill and Joe Kozfkay to see if hatchery trout can truly be made easier to catch through selective breeding. Additionally, for each tag returned, the angler's name will be entered into a water specific lottery where the winner receives $50. Drawings will be held on Dec. 31, 2002.

Stocking sites include the Middle Fork Boise River, North Fork Boise River, Boise River, Grimes Creek, Mores Creek, Silver Creek, Little Smoky Creek, Warm Springs Creek, Portneuf River, Crooked River, Rock Creek, Mores Creek, Middle Fork Weiser River, Weiser River, North Fork Payette River (2 Sites), and North Fork Lake Fork Creek.

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14. STUDY WARNS OF GLOBAL WARMING IMPACTS ON FISH HABITAT

Trout and salmon across the United States face a dismal future if global warming continues to push temperatures up in the nation's waterways, according to a study released May 21 by Defenders of Wildlife and the Natural Resources Defense Council.

Habitats for some species could shrink as much as 17 percent by 2030, 34 percent by 2060, and 42 percent by 2090 if emissions of heat-trapping pollution such as carbon dioxide are not reduced, according to the report.

The new analysis covers four species of trout -- brook, cutthroat, rainbow and brown -- and four species of salmon -- pink, coho, chinook and chum. Researchers looked at air and water temperature data from more than 2,000 sites across the United States. Using three internationally recognized climate models, they estimated changes in stream temperature under a variety of pollution scenarios.

"Rising temperatures are increasingly going to curtail the range of trout and salmon in the U.S. That means more and more of our favorite fishing holes will come up empty," said Dr. Daniel Lashof, science director of the NRDC Climate Center. "The reason is pollution from cars and power plants. Fortunately, there are measures we can take now to start solving the problem."

Salmon and trout are coldwater species, acutely sensitive to stream temperature. In many areas the fish are already living at the margin of their tolerance, meaning even modest warming can render a stream uninhabitable. Projected increases in water temperature vary by location, but average 0.7 to 1.4 degrees Fahrenheit by 2030, 1.3 to 3.2 F by 2060, and 2.2 to 4.9 F by 2090, depending on future emissions of heat-trapping gases and which climate model is used. Besides temperatures, timing of summertime highs also changes in some cases, sometimes by as much as four weeks, the study says.

The report predicts widespread habitat losses that vary by region. For trout, the most severe losses appear in the South, Southwest and Northeast. For salmon, significant losses are seen throughout their current range, with the biggest impact likely in California.

The extent of predicted habitat loss also varies somewhat by species. For example, if emissions continue to increase at current rates, rainbow trout habitat would shrink by 8 to 11 percent by 2030, 14 to 24 percent by 2060, and 24 to 38 percent by 2090. For coho salmon, by comparison, 6 to 14 percent of habitat could be lost by 2030, 16 to 30 percent by 2060, and 23 to 41 percent by 2090.

For many of the fish species, the effects of global warming come atop a battery of existing problems. Cutthroat trout, native to the western United States have been reduced to less than five percent of their original range and several subspecies are listed as threatened, according to press release.

Wild Pacific salmon have disappeared from nearly 40 percent of their historic range in the Northwest, and populations are down more than 90 percent in the Columbia River system, according to the conservation group. Chinook salmon have been listed under the Endangered Species Act, and several populations of coho are officially threatened.

"Wild trout and salmon populations are already stressed by factors such as loss of habitat to development, competition with hatchery fish, invasive exotic species, and more. Now we must add climate change to the list of challenges they face," said Mark Shaffer, senior vice president for programs at Defenders of Wildlife. "If we don't address the cumulative impact of all these factors, we will see more of these populations switching from a recreational resource to being listed as threatened or endangered."

An estimated nine million U.S. recreational anglers spend nearly 100 million days fishing each year creating an economic ripple worth billions of dollars, the groups say. Many of the species covered by the study are regional icons with cultural significance rivaling their recreational and economic value.

"This report warns us not only of losses to natural resources and family traditions, but also that the future of jobs that depend on healthy recreation are at risk," said Steve Moyer, vice president for conservation for the group Trout Unlimited. "Our grandchildren and their families may not have the pleasure of fishing for these magnificent creatures in many areas that we know and love today. Billions of dollars per year spent on recreational fishing equipment, guides and resorts may be hit too."

The study covers direct thermal effects on the stream habitats only, and does not examine indirect impacts of global warming such as changes in precipitation or evaporation. It does not include Alaska or Hawaii. Nor does it look at global warming on ocean environments where salmon and some trout species spend much of their lives.

"For many of us, coldwater fisheries are one of the things that make life worth living. This data-rich report asks some sobering questions about yet another area of our lives that may be significantly impacted by global warming," said Paul Hansen, executive director of the Izaak Walton League of America. "Many of the early actions needed to address this problem are very cost-effective, even before we consider the impact on trout and salmon, and can be taken immediately."

Solving the problem means cleaning up the pollution that causes it -- mainly carbon dioxide emissions, according to the Defenders and NRDC. Answers include cleaner, more advanced technologies in our vehicles and power plants. Congress is considering legislation called the Clean Power Act that would require power companies to reduce carbon dioxide pollution, along with several other pollutants that are harming fish stocks, the groups said.

The Natural Resources Defense Council is a national, non-profit organization of scientists, lawyers and environmental specialists dedicated to protecting public health and the environment. Founded in 1970, NRDC has more than 500,000 members nationwide, served from offices in New York, Washington, Los Angeles and San Francisco.

Link information:

NRDC: www.nrdc.org
Defenders of Wildlife: http://www.defenders.org/newsroom/

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15. AGENCY DEBUTS 'INCREDIBLE IDAHO' ONLINE MAGAZINE

Everyone with an interest in life in the Idaho outdoors and access to a computer is invited to cruise the pages of the Department of Fish and Game's new online magazine.

The Internet address for the first edition is http://www2.state.id.us/fishgame/incredid/May2002/ or it can be found in the What's News section on the main Fish and Game web site under New Additions. The publication is called "Incredible Idaho," the same name as the department's television show, which is no longer produced.

"We hope we have recaptured some of the magic of the discontinued hard-copy Idaho Wildlife magazine," Jack Trueblood, the magazine's editor, said in his introductory editorial. "An electronic magazine is a new medium for all of us, and it will probably evolve over several issues until we establish an identity, so bear with us. Along the way we will try to present solid information about Idaho's great wildlife resources and recreation opportunities."

"This is the fishing issue so we've tried to provide a summary of what last year's drought did to some of the favorite fishing waters across southern Idaho, and a prediction of what to expect as the season opens in each region," Trueblood said. "We've also included a chapter of law enforcement stories for you 'true crime' fans, news about the volunteer/reservist program, some history, and a few recipes along with lots of other information.

"One of the special things in this issue is an essay on wetlands by Chris Martin, a student at Kuna High School," Trueblood continued. "Chris sent this to the Fish and Game web site, giving us the idea of publishing a student essay each issue. If you are a high school student and would like to be in the running for this, send your essay to 'Student Essay' at incredibleid@idfg.state.id.us.

"We'll try to publish one in each issue. There is no length limit but the topic must be conservation or biology-related and not controversial; we don't want to debate the pros and cons of wolf reintroduction, for instance."

Trueblood's e-mail address for matters relating to the magazine is incredibleid@idfg.state.id.us.

The next issue of the quarterly publication is expected in August and will be focused primarily with hunting.

Link information:
IDFG: http://www2.state.id.us/fishgame/fishgame.html

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16. WASHINGTON AGENCY ASKS INPUT ON WATER QUALITY

The state Department of Ecology is updating its policy for assessing which water bodies in Washington are polluted, and the public is invited to make suggestions and comments on what should be considered.

Under the federal Clean Water Act, every two years the state is required to update its list of water bodies that are impaired due to pollution. Typically, these include bacteria, high temperatures, excess nutrients and toxic substances. The list is known as the 303(d) list, after the section of federal law that requires it.

The listing process has three phases and begins by establishing the policy that will be used to assess whether a water body should be listed as impaired. Questions for researchers include: how many samples are needed per water body to declare it polluted, and should an entire stream be listed or just segments where problems are identified?

"Listing a lake or stream as polluted is a major decision that none of us takes lightly, because public health, environmental quality and economic prosperity are all on the line," said Megan White, who manages the state agency's water-quality program. "A listing can be disheartening for a community, but it also triggers cleanup efforts that can bring people together to better protect their water quality."

The DOE has drafted an assessment policy for review and comment. Public comments will be accepted in writing through July 8.

To obtain a copy of the document or submit comments, contact Matthew Green at 360-407-6386 or 303d@ecy.wa.gov. It also may be downloaded from the Internet at http://www.ecy.wa.gov/programs/wq/303d/index.html.

Workshops have been scheduled for those who want to learn more about the assessment process. The workshops will be held twice each day, from 2 to 4 p.m., and from 6 to 8 p.m.

-- Spokane on June 5 at Spokane County Cooperative Extension, Rm. E, N. 222 Havana St.
-- Yakima on June 6 at the Department of Ecology, Central Region Office, 15 W. Yakima Ave., Ste. 200.
-- Vancouver on June 10 at the Department of Ecology, 2108 Grand Blvd.
-- Wenatchee on June 12 at Wenatchee Valley College, Wells Hall Theater, 1300 5th St.
-- Walla Walla on June 13 at Walla Walla Community College, Main Building, Rm. 185A, 500 Tausick Way.
-- Bellevue on June 19 at Department of Ecology, 3190 160th Ave. S.E.
-- Bellingham on June 20 at Bellingham Public Library, 210 Central Ave.
-- Lacey on June 27 at Dept. of Ecology, 300 Desmond Dr.

The subsequent phases of the 303(d) listing process include a call for monitoring data from lakes and streams throughout Washington, which will occur this summer, followed by comment period next fall on a draft list. The final list will be adopted early next year.

The state's current 303(d) list was developed in 1998 and names 688 water bodies as polluted.

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17. FEEDBACK: Supplementation and fishing

From Doug Dompier, Columbia River Inter-Tribal Fish Commission:

I would like to thank the Columbia Basin Bulletin for giving Don Chapman and myself the opportunity to provide some differing perspectives regarding Columbia River salmon. Although Don and my paths crossed more then 30 years ago, we chose different trails to pursue our careers in fisheries.

Even so, it is good to see that our views on supplementation are not that far apart. Additionally, I believe we both see the need for good peer reviewed science, but perhaps recognition of what constitutes good science is where our trails once again diverge.

In my opinion, the research and debate of hatchery vs. wild fish that has raged for the last 10 to 15 years is a case in point. The literature on this subject is more apt to contain philosophical dogma rather than scientific facts. Nowhere in the fisheries profession has the line that separates science from philosophy been so maligned. Rather than applying sound scientific principles and protocols, researchers fed on each other's application of genetic theories. Good peer review of the studies appeared to be lacking.

I only wish I had a dollar for every time someone raised the question why the tribes won't change their fishing methods. The tribes are not fishing for sport. Therefore, they do not advocate mass mutilation and selective fisheries of hatchery-reared fish. They advocate restoration of natural salmon runs and tribal and non-tribal fisheries on those runs.

I would also like to observe that banks are not lined up to offer loans to tribal fishers to buy fancy new high tech gear and fish traps and funds from Bonneville usually come with other strings and agendas attached. Additionally, individual fishing sites are recorded with the respective tribe. Fishers cannot simple put their nets anywhere they want.

I have also heard from tribal members that it is wrong for the sport fishers to play with their food. Akin to asking the tribal fishers to change, why not ask the sport fisher to put down his fishing rod and simply buy a punch card from the state and have him stop by one of the hatcheries and pick up a mutilated salmon. No need to waste all that "fossil fuel" running up and down the rivers chasing disfigured salmon.

Of course, both of these positions are absurd. We must stop blaming the tribal and non-tribal fishers for the mismanagement that is occurring. Rather than rewarding fishery agencies by allowing them to manipulate the salmon for their benefit, it is time to return the salmon to the rivers and streams of the Columbia River system. Remember Don that's the way it was back in the 1960s.

Good to see that Don is still actively involved in Columbia River salmon issues as it will take all perspectives and finally some good peer reviewed science to put the salmon back, where they belong, in the habitat.

Doug Dompier
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Feedback comments should be sent to Intermountain Communications by e-mail: intercom@ucinet.com. Please put "feedback" in the subject line. We encourage comments about particular stories, complaints about inaccuracies or omissions; additional information; general views about the topic covered; or opinions that counterbalance statements reported.

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