EXHIBIT NO._______ (JMR-9)
DOCKET NO._____________
2003 POWER COST ONLY RATE CASE
WITNESS: JULIA M. RYAN

**BEFORE THE**

**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

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| WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,<br>Complainant,<br>v.<br>PUGET SOUND ENERGY, INC.,<br>Respondent. | Docket No. ____________ |

**DIRECT TESTIMONY OF**
**JULIA M. RYAN**
**ON BEHALF OF PUGET SOUND ENERGY, INC.**

Ex. _________ (JMR-9)

# Upgrading the Capacity and Reliability of the BPA Transmission System

**Report to the Infrastructure Technical Review Committee**

## August 20, 2002

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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

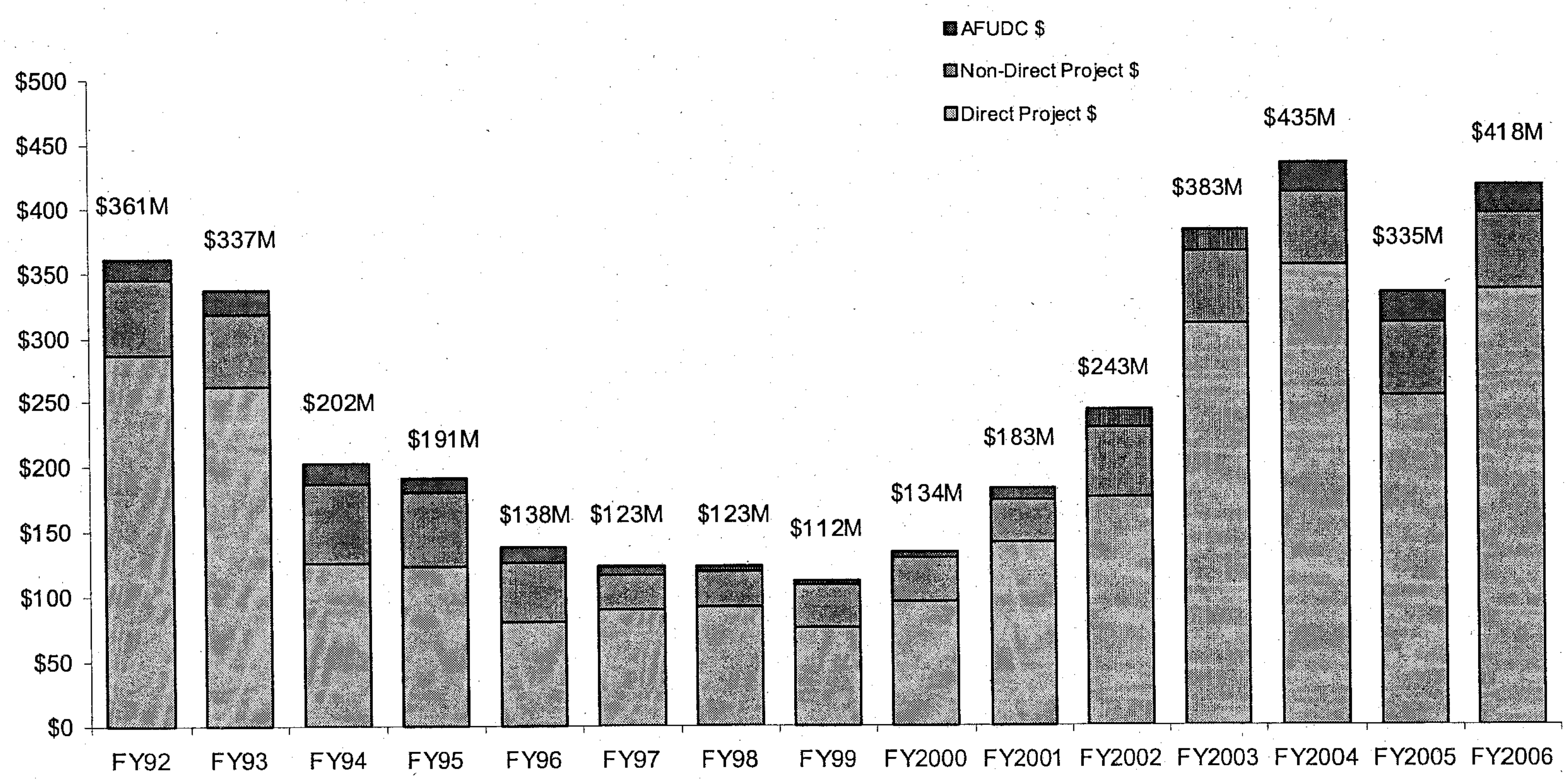
| | |
|---|---|
| BiOp | Biological Opinion |
| MW | A unit of power. One MW would serve approximately 700 homes. |
| NRTA | Northwest Regional Transmission Association |
| NWPP | Northwest Power Pool |
| RTO | Regional Transmission Organization |
| WECC | Western Electricity Coordinating Council |

**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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# 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 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.