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