Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

PUBLIC AFFAIRS

July 28, 2010

In reply refer to: DK-7

Cheryl Brantley
A Better Way for BPA

Ex 6

RE: BPA-2010-01502-F

Dear Ms. Brantley:

This is a partial release to your Freedom of Information Act (FOIA) request that you made to the Bonneville Power Administration (BPA).

You requested:
A copy of all initial documents leading to the discovery and decision to proceed with the I-5 Corridor Reinforcement Project with documentation of the electrical and economic studies showing congestion along the I-5 Corridor.

Response:
BPA has provided the following responsive documents in their entirety:
1. BPA 2008 Network Open Season/Congestion and Production Cost Analysis, January 2009
2. Draft Report – I-5 Corridor Reinforcement Project, September 7, 2007
3. Network Open Season Commercial Infrastructure Financing Policy Summary, December 9, 2008

I appreciate the opportunity to assist you with your request. If you have any questions regarding this letter, please contact Laura M. Atterbury, FOIA/Privacy Act Specialist, at (503) 230-7305.

Sincerely,

/s/Christina J. Munro

Christina J. Munro
Freedom of Information Act/Privacy Act Officer

Enclosure: Responsive Documents

Due to the size of the responsive documents they can not be posted. To obtain a copy please contact the BPA FOIA Office at 503-230-7305

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

PUBLIC AFFAIRS

August 16, 2010

In reply refer to: DK-7

Cheryl Brantley
A Better Way for BPA

Ex 6

RE: BPA-2010-01502-F

Dear Ms. Brantley:

This is the final release to a Freedom of Information Act (FOIA) request that you made to the Bonneville Power Administration (BPA).

You requested:
A copy of all initial documents leading to the discovery and decision to proceed with the I-5 Corridor Reinforcement Project with documentation of the electrical and economic studies showing congestion along the I-5 Corridor.

BPA has provided two responsive documents as follows:

1. Bonneville Power Administration, Transmission Services, Economic Planning Study Report Number BPA-TS TPP-2009-054, dated August 14, 2009 in its entirety.

2. Agency Decision Framework Analysis – 2008 Network Open Season (NOS) Project Alternatives and Recommendation released in its entirety. However, BPA redacted parts of this document pursuant to 5 U.S.C. § 552(b) (Exemption 5).

All redactions are protected attorney-client communications. They contain confidential communications between and among BPA attorneys and employees for the purposes of obtaining legal advice as part of the project review process. This legal analysis was prepared by a BPA attorney as part of the project review process in response to a request for legal advice from the BPA Administrator and agency executives. It contains the attorney's interpretations and analysis of relevant case law as well as his opinions on the legal risks associated with different potential courses of agency action.

If you choose to appeal, it must be made within thirty (30) calendar days of receipt of a letter denying any portion of the request. The appeal should be sent to the Director, Office of Hearings and Appeals, HG-1, U.S. L-Enfant Plaza Building, U.S. Department of Energy, 1000 Independence Avenue, SW, Washington, DC 20585-1615.

I appreciate the opportunity to assist you with your request. If you have any questions regarding this letter, please contact Laura M. Atterbury, FOIA/Privacy Act Specialist, at (503) 230-7305.

Sincerely,

/s/Christina J. Munro

Christina J. Munro
Freedom of Information Act/Privacy Act Officer

Enclosure: Responsive Document

BONNEVILLE
POWER ADMINISTRATION

Bonneville Power Administration
Transmission Services
Transmission Planning

Economic Planning Study Report
Report Number BPA-TS TPP-2009-054

August 14, 2009

Table of Contents

A. Introduction 1
1. Purpose 1
2. Definitions 1
3. References 2
4. Background 2
B. Assumptions and Methodology 2
1. Assumptions 2
2. Methodology 4
C. Study Results 5
1. McNary Substation 5
C.1.1 Impacted Flowgates 5
C.1.2 Subgrid Impacts/ and ATC 5
C.1.3 Cost Estimates 5
2. Grizzly Substation 6
C.2.1 Impacted Flowgates 6
C.2.2 Subgrid Impacts and ATC 6
C.2.3 Cost Estimates 6
3. Custer Substation 7
C.3.1 Impacted Flowgates 7
C.3.2 Subgrid Impacts and ATC 7
C.3.3 Cost Estimates 7
4. Longview Substation 8
C.4.1 Impacted Flowgates 8
C.4.2 Subgrid Impacts and ATC 8
C.4.3 Cost Estimates 8
5. Coos Curry Substation (Fairview Substation) 9
C.5.1 Impacted Flowgates 9
C.5.2 Subgrid Impacts and ATC 9
C.5.3 Cost Estimates 9
6. Harney Substation 10
C.6.1 Impacted Flowgates 10
C.6.2 Subgrid Impacts and ATC 10
C.6.3 Cost Estimates 10
7. Walla Walla Substation 11
C.7.1 Impacted Flowgates 11
C.7.2 Subgrid Impacts and ATC 11
C.7.3 Cost Estimates 11
8. John Day Substation 12
C.8.1 Impacted Flowgates 12
C.8.2 Subgrid Impacts and ATC 12
C.8.3 Cost Estimates 12
9. Boundary Substation 13

C.9.1 Impacted Flowgates 13
C.9.2 Subgrid Impacts and ATC 13
C.9.3 Cost Estimates 14
10. Ellensburg Substation 14
C.10.1 Impacted Flowgates 14
C.10.2 Subgrid Impacts and ATC 14
C.10.3 Cost Estimates 15
11. LaGrande Substation 15
C.11.1 Impacted Flowgates 15
C.11.2 Subgrid Impacts and ATC 15
C.11.3 Cost Estimates 16
12. Garrison Substation 16
C.12.1 Impacted Flowgates 16
C.12.2 Subgrid Impacts and ATC 16
C.12.3 Cost Estimates 17
13. Benton County (Ashe Substation) 18
C.13.1 Impacted Flowgates 18
C.13.2 Subgrid Impacts and ATC 18
C.13.3 Cost Estimates 18
14. Little Goose Substation 19
C.14.1 Impacted Flowgates 19
C.14.2 Subgrid Impacts and ATC 19
C.14.3 Cost Estimates 19
15. Hilltop Substation (Warner Substation) 20
C.15.1 Impacted Flowgates 20
C.15.2 Subgrid Impacts and ATC 20
C.15.3 Cost Estimates 20
16. Eastern Oregon (LaGrande Substation) 20

Appendix A – Original Request for Economic Planning Study 21

A. Introduction

1. Purpose

The purpose of this report is to document the Economic Planning Study performed by the Bonneville Power Administration – Transmission Services (BPA-TS) in response to an Economic Planning Study request submitted by the Bonneville Power Administration – Power Services (BPA-PS) under Attachment K of the Open Access Transmission Tariff. The original Economic Planning Study Request (Request) is in Appendix A.

The Economic Planning Study addressed in this report is a high level analysis conducted using the best available information at the time. The results are only intended to be used to develop reasonable judgments about locations for future OATT queue requests. The results do not convey or guarantee any availability of transmission service. Any transmission service for points of receipt (POR's) in this Economic Planning study must be requested and analyzed through the OATT transmission service queue.

These studies were conducted using the best available information at the time of the study. Findings are based on assumptions which are subject to change. BPA-TS reserves the right to modify the content in this report.

2. Definitions

ATC Available Transfer Capability

BPA-PS Bonneville Power Administration – Power Services

BPA-TS Bonneville Power Administration – Transmission Services

De minimis This concept is defined in BPA's ATC Methodology. It is used for determining the impact of a transmission service request across a specific flowgate. The impact from a specific POR is considered de minimis when it is less than or equal to 10 MW and less than or equal to 10% of the requested demand across the flowgate.

NOS 2008 Network Open Season

NT Network Transmission

POD Point of Delivery (where the power is delivered to)

POR Point of Receipt (where the power is injected into the network)

PUF Path Utilization Factors. These are the parameters from the basecase that indicate how power that is injected into the BPA-TS transmission system is then distributed across the ten monitored network flowgates (see Table 1). The PUF's are also known as Power Transfer Distribution Factors, or PTDF's.

TSR Transmission Service Request

3. References

- Attachment K of Open Access transmission Tariff, Section 8, which describes Economic Planning Studies.
- Request for Transmission Economic Planning Study, dated July 16, 2008. See Appendix A.
- 2008 Network Open Season Cluster Study Report

4. Background

On July 16, 2008 BPA-PS submitted a request for an Economic Planning Study to be performed by the BPA-TS. The request identified 17 different POR's with a range of MW amounts. The effective date for service was specified as 2015. The specific POR's and the proposed MW amounts are listed in Appendix A.

B. Assumptions and Methodology

1. Assumptions

Monitored Network Flowgates – This study analyzed the impact to ten existing monitored network flowgates across the BPA-TS transmission system, based on the requested POR and requested MW. The ten monitored network flowgates are defined in the BPA-TS posted ATC Methodology and are also listed below in Table 1.

Flowgate	Direction
Monroe-Echo Lake	North-to-South
Raver-Paul	North-to-South
Paul-Allston	North-to-South
Allston-Keeler	North-to-South
North of Hanford	North-to-South
North of John Day	North-to-South
West of McNary	East-to-West
West of Slatt	East-to-West
Cross Cascades North	East-to-West
Cross Cascades South	East-to-West

Table 1 Monitored Network Flowgates

Sub grid Impact – Each POR may have other impacts besides the monitored network flowgates. This Study did not examine any impacts other than the impact to the ten monitored network flowgates. This Study specifically did not examine any impacts to the sub grid or other parts of the transmission network. Some POR's, for example at main grid network points such as Grizzly, may not have any sub grid impacts, while other POR's such as Coos Curry, could have significant sub grid impacts. Other POR's such as Harney, were found to have major sub grid impacts during the 2008 Network Open Season. If sub grid impacts have been analyzed in previous studies, such as Harney, then those results will be incorporated into this report. However, if the sub grid impacts have

not been analyzed in a previous study, then they were not studied here. There may be other impacts besides the monitored network flowgates.

Composite Load – The Request specified various Points of Receipt (POR) for both potential thermal and potential renewable interconnections. Since no Points of Delivery (POD) were specified in the Request, and since Power Services is a Network Transmission customer, this Study assumed a composite area load for the Northwest as the POD.

Federal Hydroelectric Plants – In order to calculate the impacts of the POR's, the power injected into the transmission network must equal the load served. Since no new POD's were specified in the Request, and no new load was identified, this Study assumed that as the power was injected into the transmission network at the specified POR's, the existing output of the ten largest Federal hydroelectric plants would be reduced by an amount equivalent to the new power injected. In order to determine how much to reduce each of the Federal hydroelectric plants, the distribution between the ten plants was applied consistent with the assumptions used for BPA-TS ATC Methodology.

Maximum POR MW Assumed – The original Request specified 50, 150, and 300 MW of MW to be studied at POR's 6-15. The assumed network transmission obligation for BPA-PS is existing Federal generation equivalent to serve existing load. These requested POR's with their associated MW, were therefore assumed to be new resources, and by definition, exceed current network transmission obligations.

Power Transfer Distribution Factors (PUF's) were calculated from each POR to each federal network resource. If the impact is positive, that indicates an increase in flow across the flowgate, which is beyond the existing network transmission obligation. Since the PUF's are merely algebraic factors that determine how power flows across the system, a 300 MW power injection would cause twice the impact of a 150 MW power injection across a monitored flowgate. Therefore, this study only includes the results for the maximum MW requested at each POR. The impacts of lower MW amounts can be derived from these results. Because some of the monitored network flowgates are in series, the sum of the impacts on all of the flowgates may, in some cases, exceed the MW amount of the requested POR.

Available Transfer Capability (ATC) - The Study analyzed the impact to the ten monitored network flowgates. If there was an increased loading, then it was deemed to be beyond the existing network transmission obligation. However, the Study did not analyze whether there was ATC that could allow the new POR, or whether the flowgate would have to be reinforced due to a lack of ATC. It is not known prior to submission of a long term firm transmission service request whether ATC would be available for a particular POR, because it is not known what requests would be superior in the OATT queue before then. Therefore, the Study assumed there was no ATC and that the flowgate would need to be reinforced if the impact to the flowgate was not de minimis.

De minimis is when the resulting impact of the POR on the flowgate, is less than or equal to 10 MW and less than or equal to 10% of the request. If the impact is greater than this test, then it is not de minimis. For example, if a 600 MW POR at McNary results in a 285 MW impact on the West of McNary flowgate, this would not pass the test for de minimis impact, since 285 MW is greater than 10 MW and greater than 10% of the request (or 60 MW). If the impact is not de minimis, then it was assumed that the flowgate would need reinforcement in order to accommodate the request and the costs of the reinforcement (if available) are included in this report. The 2008 Network Open Season confirmed that most of the network flowgates were constrained and that there would not be ATC to include the requested POR without system reinforcement.

BPA-TS Service Area – BPA-TS has no transmission facilities in eastern Oregon east of LaGrande Substation (LaGrande, Oregon) or Harney Substation (Burns, Oregon). It is beyond the scope of this Study to evaluate the transmission facilities needed on other utilities' systems. Therefore, for each request, the Study examined the closest POR to the BPA-TS network.

Estimated Costs – The costs in this report were taken from other studies, mostly from the 2008 Network Open Season. These are non-binding good faith estimates of direct costs and do not contain any overheads. These costs are based on information available at this time and are subject to change. Refer to the 2008 Network Open Season Cluster Study report for more detail of what is included in the cost estimates.

2. *Methodology*

The study methodology was to 1) apply Path Utilization Factors, 2) inject the power at the requested POR, 3) reduce the power output of the ten federal hydroelectric plants by an amount equal to the injection at the specified POR, and 4) examine the impact across the ten monitored flowgates.

To determine the system reinforcements required to increase capacity across the flowgates, previous studies were utilized to the maximum extent possible. If the impact of a POR caused an increased loading across a flowgate that was not de minimis, the reinforcement plan of service and cost estimate from previous planning studies were used for that particular flowgate. Most of the plans of service were developed in the 2008 Network Open Season.

In the tables throughout this report, gray-shaded cells indicate flowgates with increased loading that is considered de minimis. Orange-shaded cells indicate flowgates with increased loading that is not de minimis. This indicates flowgates that may require reinforcement to accommodate the requested POR. Green-shaded cells indicate flowgates with reduced loading.

C. Study Results

1. McNary Substation

C.1.1 Impacted Flowgates

For a POR of McNary 230 kV with 600 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-22
Raver-Paul	North-to-South	-32
Paul-Allston	North-to-South	-41
Allston-Keeler	North-to-South	-30
North of Hanford	North-to-South	-189
North of John Day	North-to-South	-290
West of McNary	East-to-West	285
West of Slatt	East-to-West	132
Cross Cascades North	East-to-West	-51
Cross Cascades South	East-to-West	73

Table C.1 – 600 MW POR of McNary Substation

C.1.2 Sub grid Impacts/ and ATC

The sub grid impacts of this POR were not studied. There would likely be sub grid impacts for a POR at McNary. The West of McNary and West of Slatt network paths were constrained during the 2008 NOS and there would likely be no ATC. The Cross Cascades South path was not constrained during the 2008 NOS. However, that is no guarantee that there will be ATC should Power Services submit a TSR for a new 600 MW network resource at McNary Substation.

C.1.3 Cost Estimates

The following are non-binding good faith estimated direct costs for mitigating the impacts identified in Table C.1.

Reinforcement	**Cost ($M)**
West of McNary Reinforcement	$362
Cross Cascades South	$76
Total	**$438**

2. *Grizzly Substation*

C.2.1 Impacted Flowgates

For a POR of Grizzly 500 kV with 600 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-25
Raver-Paul	North-to-South	-505
Paul-Allston	North-to-South	-655
Allston-Keeler	North-to-South	-57
North of Hanford	North-to-South	-217
North of John Day	North-to-South	-358
West of McNary	East-to-West	-109
West of Slatt	East-to-West	-186
Cross Cascades North	East-to-West	-78
Cross Cascades South	East-to-West	9

Table C.2 – 600 MW POR of Grizzly Substation

C.2.2 Sub grid Impacts and ATC

The sub grid impacts of this POR were not studied. There was a de minimis loading increase on the Cross Cascades South path. The Cross Cascades South path was not constrained during the 2008 NOS. That is no guarantee that there will be ATC should Power Services submit a TSR for a new 600 MW network resource at Grizzly Substation.

For any POR at a substation located south of John Day to the California-Oregon border, some of the power would flow south over the 500 kV facilities feeding the California-Oregon Intertie (COI), even for a south to north transaction. The capacity on the COI in the north-to-south direction is fully subscribed. However, reinforcements along the COI transmission path are beyond the scope of impacts to the monitored flowgates which are addressed by this report. Therefore, no cost estimates were provided.

C.2.3 Cost Estimates

The Grizzly POR resulted in a de minimis loading increase on the Cross Cascades South flowgate. The other flowgates showed reduced loadings. Therefore, no reinforcement costs are included for this POR. However, there may be sub grid impacts and/or impacts to the COI, which are not accounted for here, because they are beyond the scope of this Study.

3. *Custer Substation*

C.3.1 Impacted Flowgates

For a POR of Custer 230 kV with 600 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	294
Raver-Paul	North-to-South	52
Paul-Allston	North-to-South	65
Allston-Keeler	North-to-South	51
North of Hanford	North-to-South	130
North of John Day	North-to-South	134
West of McNary	East-to-West	-21
West of Slatt	East-to-West	11
Cross Cascades North	East-to-West	-507
Cross Cascades South	East-to-West	-47

Table C.3 – 600 MW POR of Custer Substation

C.3.2 Sub grid Impacts and ATC

The sub grid impacts of this POR were not studied. There may or may not be sub grid impacts. The flowgates south of Custer substation and the West of Slatt path were constrained during the 2008 NOS and there would likely be no ATC. The North of Hanford and North of John Day paths were not constrained during the 2008 NOS. That is no guarantee that there will be ATC should Power Services submit a TSR for a 600 MW new network resource at Custer Substation.

C.3.3 Cost Estimates

The following are non-binding good faith estimated direct costs for mitigating the impacts identified in Table C.3.

Reinforcement	Cost ($M)
West of McNary Reinforcement	$362
Monroe-Echo Lake Reinforcement	$245
I-5 Corridor Reinforcement	$342
Total	**$949**

4. *Longview Substation*

C.4.1 Impacted Flowgates

For a POR of Longview 230 kV with 600 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-37
Raver-Paul	North-to-South	-167
Paul-Allston	North-to-South	-191
Allston-Keeler	North-to-South	145
North of Hanford	North-to-South	-52
North of John Day	North-to-South	-288
West of McNary	East-to-West	-64
West of Slatt	East-to-West	-49
Cross Cascades North	East-to-West	-273
Cross Cascades South	East-to-West	-265

Table C.4 – 600 MW POR of Longview Substation

C.4.2 Sub grid Impacts and ATC

The sub grid impacts of this POR were not studied. There may or may not be sub grid impacts. The Allston-Keeler network path was constrained during the 2008 NOS and there would likely be no ATC.

C.4.3 Cost Estimates

The following are non-binding good faith estimated direct costs for mitigating the impacts identified in Table C.4.

Reinforcement	**Cost ($M)**
I-5 Corridor Reinforcement	$342
Total	**$342**

5. *Coos Curry Substation (Fairview Substation)*

C.5.1 Impacted Flowgates

For a POR in the Coos Curry area, the closest BPA-TS substation was assumed, Fairview substation. For a POR of Fairview 115 kV with 200 MW, there were no increased loadings on the monitored network flowgates.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-13
Raver-Paul	North-to-South	-33
Paul-Allston	North-to-South	-43
Allston-Keeler	North-to-South	-39
North of Hanford	North-to-South	-98
North of John Day	North-to-South	-175
West of McNary	East-to-West	-48
West of Slatt	East-to-West	-65
Cross Cascades North	East-to-West	-51
Cross Cascades South	East-to-West	-163

Table C.5 – 200 MW POR of Fairview Substation

C.5.2 Sub grid Impacts and ATC

The sub grid impacts of this POR were not studied. There will almost certainly be sub grid impacts and associated reinforcement costs for injecting 200 MW into the southern Oregon coast transmission system. However, there were no studies available to estimate these costs. The Study did show, as expected, that for an injection of power in this part of the system, no main grid flowgates would be impacted.

C.5.3 Cost Estimates

There will likely be costs to mitigate the sub grid impacts in the southern Oregon coastal area, but there were no previous studies available to obtain a plan of service and cost estimates from.

6. *Harney Substation*

C.6.1 Impacted Flowgates

For a POR of Harney 115 kV with 300 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-13
Raver-Paul	North-to-South	-26
Paul-Allston	North-to-South	-34
Allston-Keeler	North-to-South	-29
North of Hanford	North-to-South	-106
North of John Day	North-to-South	-177
West of McNary	East-to-West	-53
West of Slatt	East-to-West	-86
Cross Cascades North	East-to-West	-41
Cross Cascades South	East-to-West	-7

Table C.6 – 300 MW POR of Harney Substation

C.6.2 Sub grid Impacts and ATC

The sub grid impacts of this POR were studied under the 2008 NOS. This Request would require substantial reinforcement of the network from Harney to central Oregon. Given the length of the line, the performance of 230 kV system reinforcement was marginal and 500 kV was preferred. Any 500 kV plan of service, would interconnect with a substation between John Day and the California Oregon border.

For any POR at a substation located south of John Day to the California-Oregon border, some of the power would flow south over the 500 kV facilities feeding the COI, even for a south to north transaction. The capacity on the COI in the north-to-south direction is fully subscribed. However, reinforcements along the COI transmission path are beyond the scope of impacts to the monitored flowgates which are addressed by this report. Therefore, no cost estimates were provided.

C.6.3 Cost Estimates

The following are non-binding good faith estimated direct costs for mitigating just the sub grid impacts in the Harney area. This does not include any costs to mitigate potential impacts to the COI.

Reinforcement	**Cost ($M)**
Harney Area Reinforcement	$360
Total	**$360**

7. *Walla Walla Substation*

C.7.1 Impacted Flowgates

For a POR of Walla Walla 115 kV with 300 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-9
Raver-Paul	North-to-South	-7
Paul-Allston	North-to-South	-9
Allston-Keeler	North-to-South	-7
North of Hanford	North-to-South	-59
North of John Day	North-to-South	-9
West of McNary	East-to-West	70
West of Slatt	East-to-West	46
Cross Cascades North	East-to-West	-12
Cross Cascades South	East-to-West	-24

Table C.7 – 300 MW POR of Walla Walla Substation

C.7.2 Sub grid Impacts and ATC

The sub grid impacts of this POR were not specifically studied. However, the Walla Walla area is served by 115 kV transmission and is a relatively weak system. As part of the Generator Interconnection process, BPA-TS has studied several interconnections in the Walla Walla area. To interconnect new generation of approximately 300 MW in the Walla Walla area, it was determined that Walla Walla Substation would require development of a 230 kV yard. It would require a new 300 MVA, 230/115 kV transformer at Walla Walla, a new 230 kV line from Walla Walla to McNary and a second 1300 MVA 500/230 kV transformer at McNary. These costs would be on the order of $80 M total ($30M for additions at McNary, $40M for 51 miles of new 230 kV line, and $10M for the development of a new 230 yard at Walla Walla) There may or may not be other sub grid impacts. The West of McNary and West of Slatt network paths were constrained during the 2008 NOS and there would likely be no ATC.

C.7.3 Cost Estimates

The following are non-binding good faith estimated direct costs for mitigating the impacts identified in Table C.7.

Reinforcement	**Cost ($M)**
West of McNary Reinforcement	$362
Walla Walla Area reinforcements	$80
Total	**$442**

8. *John Day Substation*

C.8.1 Impacted Flowgates

For a POR of John Day 500 kV with 300 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-12
Raver-Paul	North-to-South	-23
Paul-Allston	North-to-South	-30
Allston-Keeler	North-to-South	-26
North of Hanford	North-to-South	-112
North of John Day	North-to-South	-180
West of McNary	East-to-West	-52
West of Slatt	East-to-West	-86
Cross Cascades North	East-to-West	-36
Cross Cascades South	East-to-West	37

Table C.8 – 300 MW POR of John Day Substation

C.8.2 Sub grid Impacts and ATC

The sub grid impacts of this POR were not studied. There may or may not be sub grid impacts. This POR resulted in increased loading on the Cross Cascades South flowgate. The Cross Cascades South path was not constrained during the 2008 NOS. That is no guarantee that there will be ATC should Power Services submit a TSR for a new 300 MW network resource at John Day Substation.

John Day is the northern terminus of the COI. For any POR at a substation located from John Day south to the California-Oregon border, some of the power would flow south over the 500 kV facilities feeding the COI, even for a south to north transaction. The capacity on the COI in the north-to-south direction is fully subscribed. However, reinforcements along the COI transmission path are beyond the scope of impacts to the monitored flowgates which are addressed by this report. Therefore, no cost estimates were provided.

C.8.3 Cost Estimates

The following are non-binding good faith estimated direct costs for mitigating the impacts identified in Table C.8. This does not include any costs to mitigate potential impacts to the COI.

Reinforcement	**Cost ($M)**
Cross Cascades South	$ 76
Total	**$76**

9. *Boundary Substation*

C.9.1 Impacted Flowgates

For a POR of Boundary 230 kV with 300 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-1
Raver-Paul	North-to-South	7
Paul-Allston	North-to-South	11
Allston-Keeler	North-to-South	8
North of Hanford	North-to-South	21
North of John Day	North-to-South	69
West of McNary	East-to-West	6
West of Slatt	East-to-West	20
Cross Cascades North	East-to-West	13
Cross Cascades South	East-to-West	2

Table C.9 – 300 MW POR of Boundary Substation

C.9.2 Sub grid Impacts and ATC

The sub grid impacts of this POR were not studied. It is expected that there would be sub grid impacts. In addition to impacts across monitored flowgates, there could be impacts to the transmission system between Boundary and Bell. Presently, there are three 230 kV and one 115 kV line in this path. BPA-TS has existing obligations for Boundary generation up to 1050 MW. Based on existing obligations and potential requests in the OATT queue, studies in response to transmission service requests may show that system expansion is needed between Boundary and Bell substations. The degree of expansion could range from a new 230/115 kV transformer and multiple line upgrades to a new 230 kV transmission line.

The BPA-TS allocation across the West of Hatwai (WOH) path is also congested. Existing obligations across this path include both Montana to Northwest transfers as well as federal western Montana hydro generation. Based on existing obligations and potential requests in the OATT queue, studies in response to transmission service requests may show that system expansion is needed across the WOH path. This may include a new Bell-Ashe 500 kV transmission line (approximately 145 miles) or equivalent.

The Boundary POR increased the loading to varying degrees on every monitored flowgate except Monroe-Echo Lake. Even if, electrically, the sub grid impacts of this POR could be mitigated with system reinforcements, there are still scheduling issues that need to be resolved. The West of Slatt network path was constrained during the 2008 NOS and there would likely be no ATC. The Cross Cascades South, Cross Cascades North, North of Hanford and North of John Day paths were not constrained during the 2008 NOS. However, cost estimates were created during the 2008 NOS for some of

these projects. That is, no guarantee that there will be ATC should Power Services submit a TSR for a new 300 MW network resource at Boundary Substation.

C.9.3 Cost Estimates

The following are non-binding good faith estimated direct costs for mitigating the impacts identified in Table C.9. This does not include the costs to reinforce the West of Hatwai path or the system between Boundary and Bell, because these are beyond the scope of this Study.

Reinforcement	**Cost ($M)**
West of McNary Reinforcement	$362
Cross Cascades North	$29
Total	**$391**

10. Ellensburg Substation

C.10.1Impacted Flowgates

For a POR of Ellensburg 115 kV with 300 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-7
Raver-Paul	North-to-South	6
Paul-Allston	North-to-South	9
Allston-Keeler	North-to-South	7
North of Hanford	North-to-South	61
North of John Day	North-to-South	46
West of McNary	East-to-West	0
West of Slatt	East-to-West	12
Cross Cascades North	East-to-West	2
Cross Cascades South	East-to-West	4

Table C.10 – 300 MW POR of Ellensburg Substation

C.10.2Sub grid Impacts and ATC

The sub grid impacts of this POR were not studied. There would be sub grid impacts for a 300 MW POR on the 115 kV system. This POR impacted every monitored flowgate except Monroe-Echo Lake. The Cross Cascades South, Cross Cascades North, North of Hanford and North of John Day paths were not constrained during the 2008 NOS. However, cost estimates were created during the 2008 NOS for some of these projects. Although these paths were not identified as constrained in the 2008 NOS, that is no guarantee that there will be ATC should Power Services submit a TSR for a new 300 MW network resource at Ellensburg Substation.

C.10.3 Cost Estimates

The following are non-binding good faith estimated direct costs for mitigating the impacts identified in Table C.10.

Reinforcement	**Cost ($M)**
West of McNary Reinforcement	$362
Total	**$362**

11. LaGrande Substation

C.11.1 Impacted Flowgates

For a POR of LaGrande 230 kV with 300 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-11
Raver-Paul	North-to-South	-16
Paul-Allston	North-to-South	-21
Allston-Keeler	North-to-South	-15
North of Hanford	North-to-South	-94
North of John Day	North-to-South	-144
West of McNary	East-to-West	142
West of Slatt	East-to-West	66
Cross Cascades North	East-to-West	-25
Cross Cascades South	East-to-West	37

Table C.11 – 300 MW POR of LaGrande Substation

C.11.2 Sub grid Impacts and ATC

The sub grid impacts of this POR were studied during the 2008 NOS. The West of McNary and West of Slatt network paths were constrained during the 2008 NOS and there would likely be no ATC. The Cross Cascades South path was not constrained during the 2008 NOS. That is no guarantee that there will be ATC should Power Services submit a TSR for a new 300 MW network resource at LaGrande Substation.

The 2008 NOS concluded that a new 230 kV line would need to be constructed on the BPA-TS network between McNary substation and LaGrande. Also, Idaho Power Company (IPC) owns the network east of LaGrande and they would need to construct a new 230 kV line from LaGrande east to the Boise area. The 2008 NOS estimates do not reflect the costs of any reinforcements on IPC's system. IPC is considering a new 500 kV line from the Boise area to the Boardman area. IPC would probably not consider a new 230 kV line from Boise to LaGrande while their 500 kV line was still being

considered. If that 500 kV project moves forward, there may be capacity available, assuming the POR was connected to the 500 kV line.

C.11.3 Cost Estimates

The following are non-binding good faith estimated direct costs for mitigating the impacts identified in Table C.11.

Reinforcement	**Cost ($M)**
West of McNary Reinforcement	$362
Cross Cascades South	$76
LaGrande Area Reinforcements (BPA-TS portion)	$68
Total	**$506**

12. Garrison Substation

C.12.1 Impacted Flowgates

For a POR of Garrison 230 kV with 300 MW, the following monitored network flowgates were impacted.

Flowgate	**Direction**	**Impact (MW)**
Monroe-Echo Lake	North-to-South	-3
Raver-Paul	North-to-South	4
Paul-Allston	North-to-South	6
Allston-Keeler	North-to-South	4
North of Hanford	North-to-South	-11
North of John Day	North-to-South	73
West of McNary	East-to-West	12
West of Slatt	East-to-West	26
Cross Cascades North	East-to-West	7
Cross Cascades South	East-to-West	7

Table C.12 – 300 MW POR of Garrison Substation

C.12.2 Sub grid Impacts and ATC

The West of McNary and West of Slatt network paths were constrained during the 2008 NOS, and there would likely be no ATC. The North of John Day path was not constrained during the 2008 NOS. However, that is no guarantee that there will be ATC across the monitored network flowgates, should Power Services submit a TSR for a new 300 MW network resource at Garrison Substation.

A POR at Garrison may require a transmission service request across the Montana Intertie as well as over the BPA network depending on the location of the resource

associated with the request. There is no guarantee that there will be ATC should Power Services submit a TSR for service across that intertie.

Based on existing obligations and potential requests in the OATT queue in the future, studies in response to transmission service requests may show system expansion would be needed between Montana and the Northwest. System expansion could range from additions to existing remedial action schemes, to new 500 kV system expansion such as series capacitors or a 500 kV transmission line.

The BPA-TS allocation across the West of Hatwai (WOH) flow path is also congested. Existing obligations across this path include both Montana to Northwest transfers as well as federal western Montana hydro generation. Based on existing obligations and potential requests in the OATT queue, studies in response to transmission service requests may show that system expansion would be required across the WOH flow path. This could include a new Bell-Ashe 500 kV transmission line (approximately 145 miles) or equivalent.

Reinforcements to the Montana-Northwest path or to the West of Hatwai flow path are beyond the scope of impacts to the monitored flowgates which are addressed by this report. Therefore, no cost estimates are provided for reinforcing these paths.

C.12.3 Cost Estimates

The following are non-binding good faith estimated direct costs for mitigating the impacts identified in Table C.12. The total does not include the cost to reinforce the Montana-Northwest path or the West of Hatwai path for the reason described above.

Reinforcement	**Cost ($M)**
West of McNary Reinforcement	$362
Total	**$362**

13. Benton County (Ashe Substation)

C.13.1 Impacted Flowgates

For a POR in the Benton County, Washington area, the request specified a point on the Ashe-Marion 500 kV line. This Study assumed a POR of BPA-TS' Ashe Substation, which is the closest substation to the requested POR. For a POR of Ashe 500 kV with 300 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-11
Raver-Paul	North-to-South	-7
Paul-Allston	North-to-South	-9
Allston-Keeler	North-to-South	-9
North of Hanford	North-to-South	-144
North of John Day	North-to-South	95
West of McNary	East-to-West	-8
West of Slatt	East-to-West	40
Cross Cascades North	East-to-West	-11
Cross Cascades South	East-to-West	24

Table C.13 – 300 MW POR of Ashe Substation

C.13.2 Sub grid Impacts and ATC

The sub grid impacts of this POR were not studied. There may or may not be sub grid impacts. The West of Slatt network path was constrained during the 2008 NOS and there would likely be no ATC. The Cross Cascades South and the North of John Day flowgates were not constrained during the 2008 NOS. That is no guarantee that there will be ATC should Power Services submit a TSR for a 300 MW new network resource at Ashe Substation. Cost estimates are provided for the West of McNary Reinforcement (which includes West of Slatt) and the Cross Cascades South, but no studies were done for the North of John Day reinforcement and therefore no cost information is available for this path.

C.13.3 Cost Estimates

The following are non-binding good faith estimated direct costs for mitigating the impacts identified in Table C.13.

Reinforcement	**Cost ($M)**
West of McNary Reinforcement	$362
Cross Cascades South	$76
Total	**$438**

14. Little Goose Substation

C.14.1 Impacted Flowgates

The Request specified a POR along the line between Little Goose and Lower Granite Substations. For the Study, the POR was assumed to be the closest existing station which is Little Goose Substation. For a POR of Little Goose 500 kV with 300 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-9
Raver-Paul	North-to-South	-5
Paul-Allston	North-to-South	-7
Allston-Keeler	North-to-South	-7
North of Hanford	North-to-South	-113
North of John Day	North-to-South	89
West of McNary	East-to-West	28
West of Slatt	East-to-West	42
Cross Cascades North	East-to-West	-8
Cross Cascades South	East-to-West	21

Table C.14 – 300 MW POR of Little Goose Substation

C.14.2 Sub grid Impacts and ATC

The sub grid impacts of this POR were studied as part of the 2008 NOS. These costs are included as part of the Little Goose Area Reinforcement. The West of McNary and West of Slatt network flowgates were constrained during the 2008 NOS and there would likely be no ATC. The Cross Cascades South and North of John Day Paths were not constrained during the 2008 NOS. However, that is no guarantee that there will be ATC should Power Services submit a TSR for a new 300 MW network resource at or near Little Goose Substation. No studies were available to estimate the cost of reinforcing North of John Day and therefore no costs for this flowgate are included in the total, below.

C.14.3 Cost Estimates

The following are non-binding good faith estimated direct costs for mitigating the impacts identified in Table C.14.

Reinforcement	**Cost ($M)**
West of McNary Reinforcement	$362
Cross Cascades South	$76
Little Goose Area Reinforcement	$100
Total	**$538**

15. Hilltop Substation (Warner Substation)

C.15.1 Impacted Flowgates

The Request specified a POR of Hilltop Substation. However, Hilltop is owned and operated by Sierra Pacific, not BPA-TS. BPA-TS owns the 230 kV line, but not the station. For study purposes, a POR of Warner Substation was selected, which is the nearest BPA-owned Substation located approximately 8 circuit miles from Hilltop Substation. For a POR of Warner 230 kV with 300 MW, the following monitored network flowgates were impacted.

Flowgate	Direction	Impact (MW)
Monroe-Echo Lake	North-to-South	-13
Raver-Paul	North-to-South	-27
Paul-Allston	North-to-South	-35
Allston-Keeler	North-to-South	-31
North of Hanford	North-to-South	-106
North of John Day	North-to-South	-178
West of McNary	East-to-West	-53
West of Slatt	East-to-West	-87
Cross Cascades North	East-to-West	-42
Cross Cascades South	East-to-West	-31

Table C.15 – 300 MW POR of Warner Substation

C.15.2 Sub grid Impacts and ATC

As expected, with a POR this far south on the BPA-TS system, none of the monitored network flowgates were impacted. The sub grid impacts of this POR were not studied. There would likely be sub grid impacts for a 300 MW TSR from Warner (or Hilltop). BPA-TS has no current studies to assess the sub grid impacts of a POR at Hilltop Substation.

C.15.3 Cost Estimates

There are no cost estimates available to assess the sub grid impacts of a POR of Hilltop 230 kV.

16. Eastern Oregon (LaGrande Substation)

The Request specified a POR approximately 90 miles northwest of Boise, Idaho for 50 MW. The closest BPA-TS facility northwest of Boise would be LaGrande Substation. The impacts of a POR at LaGrande were already discussed in Section 11 of this report. Refer to Section 11 for a description of the impacts of this POR and associated costs of reinforcements.

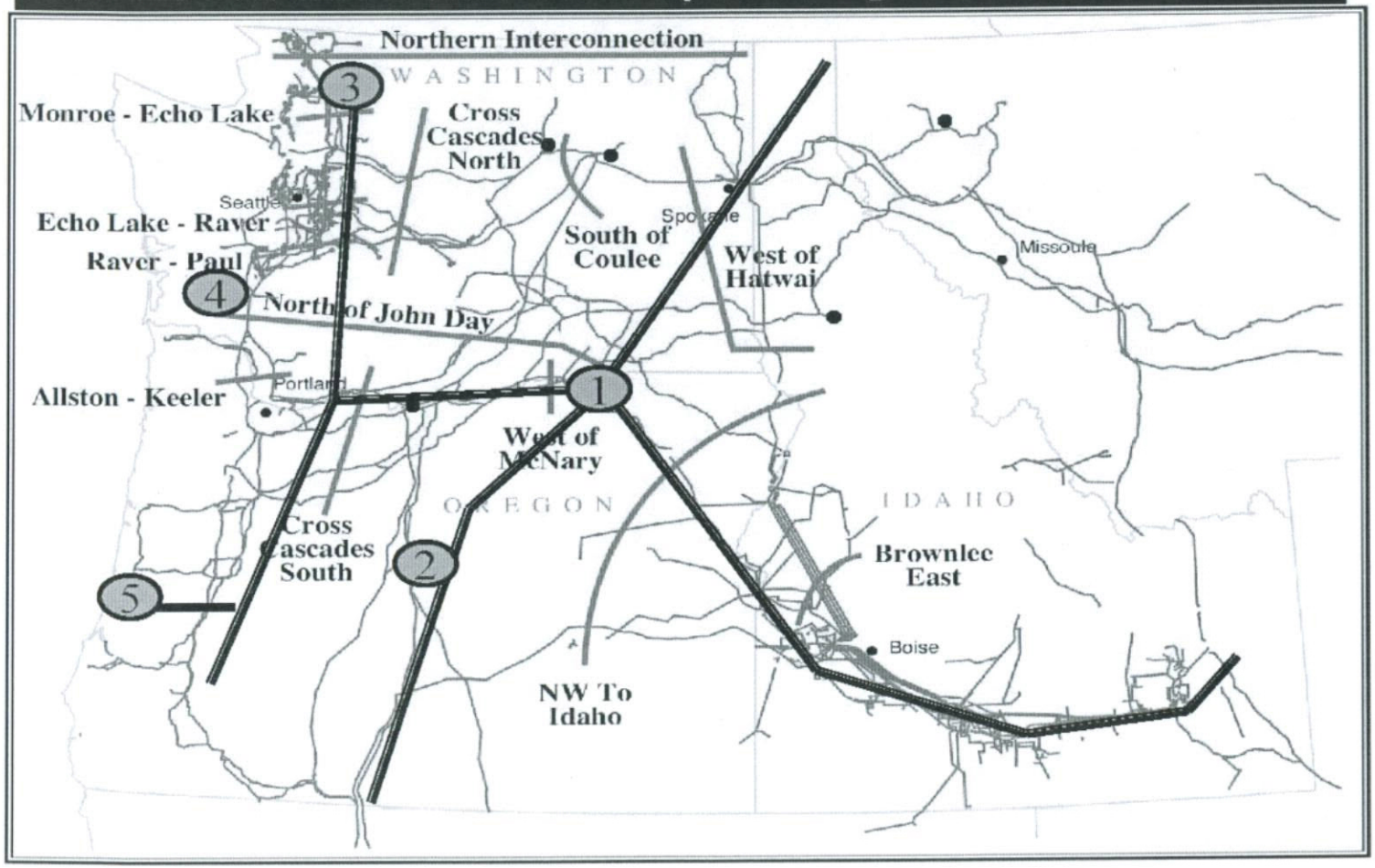
Appendix A – Original Request for Economic Planning Study

Note: The following attachment to the Request was edited slightly from the original Request. The original Request contained 16 POR's but skipped POR number 13 and included POR numbers 1-12 and 14-17. Therefore the POR's were renumbered slightly to be consecutive and the drawing revised to match.

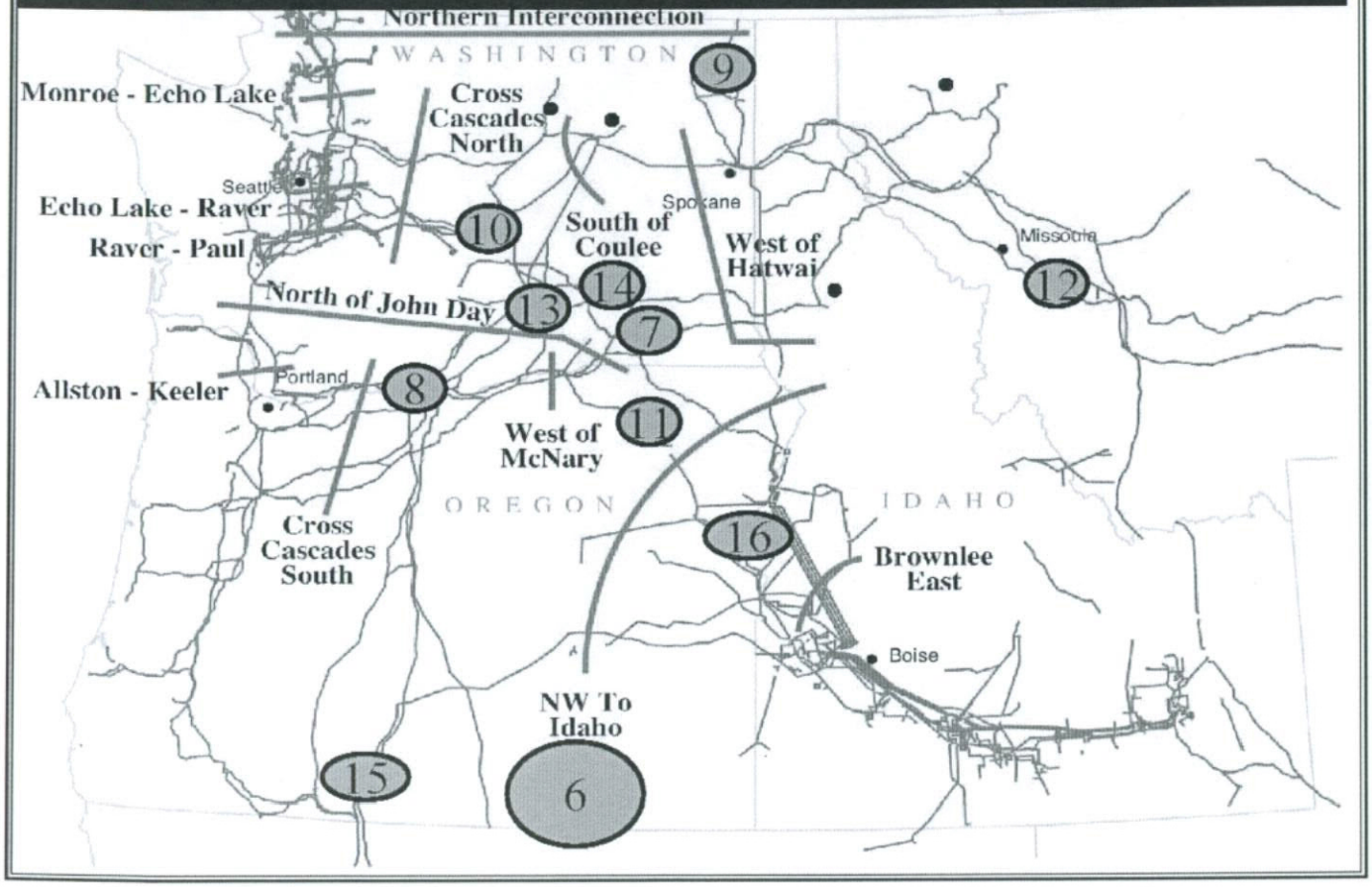
Description of areas for economic analysis

Identifier	MW (Up to)	Description : In the vicinity of……
1	600MW	McNary Substation
2	600MW	Grizzley Substation
3	600MW	Custer Substation
4	600MW	Longview Substation
5	200MW	Coos Curry Substation
6	50MW 150MW and 300MW	Harney County near French Glen, Lake County or Crook County (does this need to be split??) (please also look at an interconnection on the Malin- Hilltop line)
7		Walla-Walla Substation
8		John Day Substation
9		Boundary (energy delivered in from Canada)
10		Ellensburg Substation
11		LaGrande Substation (energy delivered in from Idaho or Wyoming)
12		Garrison (or Hotsprings) Substation (energy delivered in from Montana)
14		Benton County on the Ashe-Marion 500 KV line
15		Columbia and Garfield Counties at or on the line between the Lower Granite and Little Goose Substation.
16		Hilltop Substation (from Sierra's system) – please include the cost of a BPA 230KV/500KV transformer at Malin.
17	50 MW	Eastern Oregon; approximately 90 miles northwest of Boise (geothermal)

Electric and Gas Transmission Systems – potential thermal areas



Transmission Systems – potential renewable areas and interconnections



2008 Network Open Season (NOS)
Project Alternatives and Recommendation

1) Objectives:

Decide which expansion facilities BPA will propose to undertake in response to its 2008 Network Open Season obligations, which require BPA to determine whether the service over the expansion facilities identified in the NOS Cluster Study can be provided under the PTP or NT rate schedule (rolled-in rate determination).

The selected transmission expansion projects will be advanced to the Capital Allocation Board (CAB) for authorization and funding of National Environmental Policy Act (NEPA) work, including preliminary engineering and design required to identify alternatives and evaluate environmental impacts.

Proposed Projects: McNary-John Day, Big Eddy-Station Z, Little Goose and West of Garrison Remedial Action Scheme.

2) Agency Strategic Direction:

- *S1-Policy & Regional Actions-BPA policies result in regional actions that ensure adequate, efficient and reliable regional transmission and power services.*
- *S4-Open, non-discriminatory transmission services are provided at rates that are kept low through achievement of BPA's objective at the lowest practical cost.*
- *F2-Cost Recovery-BPA consistently recovers its costs over time.*
- *I4-Asset Management-Integrated asset management practices maximize the long-term value of FCRPS assets.*
- *I8- Transparency- BPA process, decision making and performance are transparent.*
- *I9-Collaboration-Collaborative relationships with customers, constituents and tribes are supported by our managing to clear, long-term objectives with reliable results.*

3) Decision Makers and NOS Team:

Decision makers

VP Sponsors

- Steve Wright
- Cathy Ehli
- Brian Silverstein
- Vickie VanZandt
- Dave Armstrong
- Elliot Mainzer

NOS Management and Supervisory Team

- Mary Jensen
- Dave Fitzsimmons
- Bob King
- Melvin Rodrigues
- Claudia Andrews
- Sue Holden-Baker
- Kammy Rogers-Holiday
- Dennis Oster

Team Members

- Mark Jackson
- Sean Egusa
- Doug Johnson
- Chuck Combs
- Len Morales
- Robert Shier
- Jon Dull
- Erik Westman

- Matt Perkins
- Rebecca Fredrickson
- Tim Hein
- Danny Chen
- Dennis Stevens
- Chuck Matthews
- Mike DeWolf
- Damen Bleiler
- Ken Marks
- David Barringer
- Susan Millar
- David Manary
- Ravi Aggarwal
- Don Rose
- Gene Lynard
- Mark Korsness
- Gary Beck
- Maryam Asgharian
- Virginia Schaeffer
- Kyle Kohne
- Pat Rochelle
- Ryan Josephson

4) Background and Context:

BPA initiated the NOS on April 15, 2008. PTSA agreements were offered to customers that submitted valid Transmission Service Requests (TSR) on OASIS prior to May 15, 2008. At the close of NOS on June 16, 2008, BPA received signed PTSA agreements from 28 customers. These agreements obligate customers to purchase long-term transmission service consistent with their Transmission Service Agreements provided that certain conditions are met. In total these agreements reflect long-term service commitments for 6,410 MW. BPA filed tariff revisions regarding the NOS procedures with the Federal Energy Regulatory Commission on March 31, 2008, and FERC issued an order substantially approving the filing on June 13, 2008.

Following the close of NOS, BPA removed NOS-eligible TSRs for which customers did not sign a PTSA from the long-term TSR queue and determined that BPA had sufficient ATC (Available Transfer Capability) to enable 1,782 MW of the 6,410 MW of service without the construction of expansion facilities.

The PTSA obligates BPA to take the following actions:

- At BPA's expense, conduct a Cluster Study to determine system impacts and to identify new facilities, modifications, or upgrades to BPA's network in order to provide the requested service. BPA completed the Cluster Study on November 1, 2008.
- Evaluate the estimated cost and benefits of proposed expansion facilities consistent with the Commercial Infrastructure Finance Policy (CIFP). BPA completed the CIFP evaluation on January 5, 2009.
- Decide whether BPA can construct the necessary expansion facilities and transmission service "can reasonably be provided under the applicable PTP or NT rate schedule" (rolled-in rate determination).
- Fund NEPA studies for evaluating the environmental impacts of new facilities that satisfy the rolled-in rate determination, including preliminary engineering and design work necessary to carry out the environmental reviews. This was scheduled for CAB decision on January 30, 2009.
- Where BPA determines that transmission service cannot be provided under the applicable PTP or NT rate schedule at the rolled-in rate, BPA must notify the affected customers no later than February 13, 2009.
- For each project, BPA has the right to choose any alternatives considered in the NEPA review, including the no build alternative. BPA must complete NEPA reviews no later than 36 months from posting of the rolled-in rate determination, which results in a target date for completion of NEPA review no later than Feb. 16, 2012.
- If BPA decides to build the necessary facilities, BPA will finance and construct new facilities.

Timeframe for the decision:

Written notification must be provided to each customer holding a PTSA no later than February 13, 2009.

2008 Network Open Season Cluster Study Summary:

The following figure shows how the PTSA were grouped for identifying flow gate impacts, proposed facilities and costs:

PTSA Grouping

Grouping	PTSA	Demand
Authorize -- Pre NOS (no new facilities required)	4 PTSA	55 MW
Authorize—Post NOS† (no new facilities required)	43 PTSA	1,727 MW
West of McNary Reinforcement	45 PTSA	2,023 MW
I-5 Corridor Reinforcement	2 PTSA	150 MW
Little Goose Area Reinforcement	5 PTSA	200 MW
West of McNary & West of Garrison RAS±	1 PTSA	91 MW
Harney Area Reinforcement	28 PTSA	775 MW
Northern Intertie Reinforcement	2 PTSA	100 MW
West of McNary & LaGrande Area Reinforcements‡	2 PTSA	54 MW
West of McNary & I-5 Corridor Reinforcements	6 PTSA	495 MW
West of McNary & Little Goose Area Reinforcements	13 PTSA	640 MW
West of McNary & I-5 & Little Goose Area Reinforcements	2 PTSA	100 MW
NOS -- TSR Groupings	153 PTSA	6,410 MW

† Includes one PTSA split into two partial TSR's

± Includes one PTSA with a partial TSR (parent PTSA in West of McNary)

‡ Includes one PTSA with a partial TSR (parent PTSA in West of McNary)

New facilities that are necessary to enable service to all PTSAs in the Cluster Study are as follows:

A. West of McNary Reinforcement (WOMR)
   a. Group One:
      i. McNary-John Day 500-kV (79 miles)
      ii. McNary-Ross 345-kV sag upgrade
      iii. Big Eddy-Ostrander 500-kV sag upgrade
      iv. John Day-Big Eddy 500 kV No. 2 reconductor
      v. 230-kV shunt capacitor addition at Jones Canyon
      vi. RAS addition at McNary – McNary 500/230 kV transformer outage
   b. Group Two:
      i. New 500-kV Station (Z)
      ii. Big Eddy-Station Z 500-kV (28 miles)
B. I-5 Corridor Reinforcement
   a. New 500-kV Station (Castle Rock)
   b. Castle Rock-Troutdale 500-kV (70 miles) or Castle Rock-Pearl 500-kV (90 miles)
C. Little Goose Area Reinforcement
   a. New 500-kV Station-Lower Monumental 500-KV (40 miles)
D. West of Garrison Remedial Action Scheme (RAS)
   a. RAS addition at Garrison – generation tripping
E. Harney Area Reinforcement
   a. Harney-Malin 500-kV (179 miles)
F. Northern Intertie Reinforcement
   a. Monroe-Echo Lake 500-kV No. 2 (33 miles)
G. LaGrande Area Reinforcement
   a. McNary-LaGrande 230-kV (83 miles)
   b. LaGrande-Brownlee 230-kV (79 miles)

The Cluster Study report is attached as an embedded document (click on the icon to open the Cluster Study report).

2008 NOS Cluster Study

The following summarizes estimated direct costs for new facilities identified in the 2008 NOS cluster study:

Project Cost and Schedule

Estimated Direct Costs Only (no overheads)

Project-Description	Estimated Total Cost ($k) / Confidence Level	Proposed Energ. Date
McNary-John Day + Other Upgrades	$246,545 / High	Dec-12
Station Z + Big Eddy-Station Z	$115,658 / Medium	Feb-13
I-5 Corridor Reinforcement Total	$341,996 / Medium	Sep-15
Little Goose Area Reinforcement Total	$99,435 / Medium	Sep-13
West of Garrison RAS	$2,300 / Low	Sep-11
Harney Area Reinforcement Total	$359,589 / Low	Sep-14
Northern Intertie Reinforcement Total	$225,301 / Low	Sep-15
LaGrande Area Reinforcement Total	$131,989 / Low	Sep-14
Total	$1,522,813	

Notes:

1. Estimated costs in FY08 dollars.
2. Energization dates assume rolled-in rate determination is made in Feb. 2009.

The following figure presents the forecasted schedule of direct capital costs for each project included in the recommendation. Costs include work for NEPA:

	A	B	C	D	E	F	FY Annual Direct Costs - $M						
	Project Description	Direct Cost $M	Loadings	AFUDC	Total Cost	Energ. Date	2009	2010	2011	2012	2013	2014	2015
1	WOMR	362	83	48	493	Feb-13	18	102	105	123	14	0	0
2	I-5 Corridor Reinforcement Total	342	79	43	464	Sep-15	2	12	7	85	85	75	75
3	Little Goose Area Reinforcement Total	99	23	10	132	Sep-13	1	7	28	30	33	0	0
4	West of Garrison RAS	2	1	0.4	3	Sep-11	0	1	1	0	0	0	0
5	Total	805	185	102	1,092		21	122	142	238	132	75	75

NOS Financial and Rate Impact Analysis:
A Net Present Value (NPV) and rate analysis was performed for the projects required to enable service in accordance with the CIFP. This analysis was organized as follows: 1) each project and the service enabled by the project was individually evaluated as an independent capital project; 2) all expansion projects necessary to enable service to all PTSA customers were evaluated; and 3) evaluations were performed for several scenarios identified in the Cluster Study.

The CIFP presentation is attached as an embedded document. Click on the icon to open the presentation:

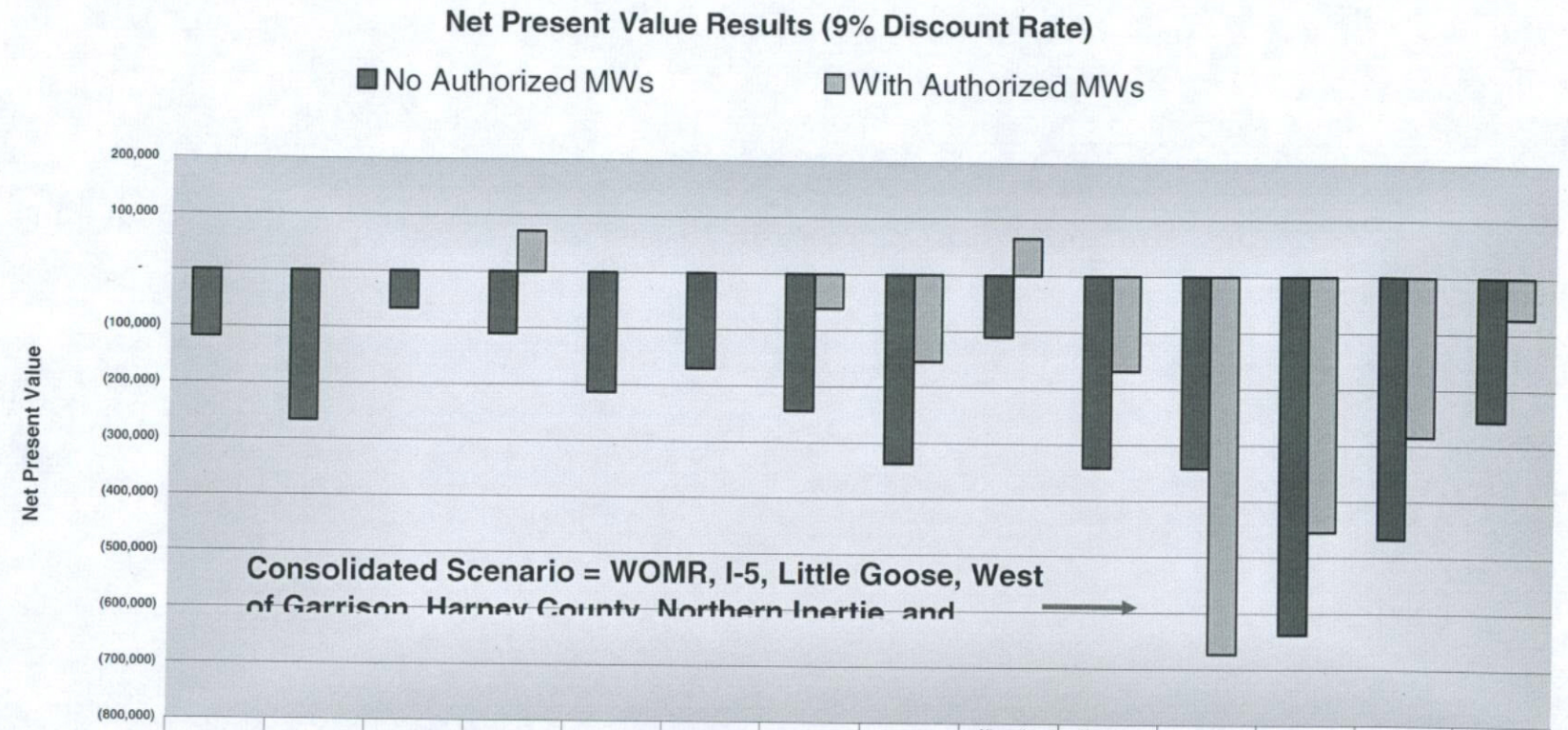
2008 NOS CIFP Analysis

The following are the base point assumptions used in the NPV and rate analysis modeling:

- Discount rate of 9%.
- Overhead rate for NPV of $2 million per project per construction year.
- Overhead rate for rate impact analysis only of 23%.
- 1% rate increase per year.
- 2% inflation rate.
- Reliability benefits identified in the Cluster Study were taken into account.
- Revenues begin at the start of the year after completion of expansion facilities.
- PTSAs were assumed to roll over for the life of the expansion facilities (all PTSAs have duration of more than five years).
- Project cost and revenues not adjusted for risk.
- Revenues from PTSAs for which service can be provided from existing ATC (1,782 MW, without constructing additional facilities) were not included in the NPV analysis but were included in the determination of rate impact.

None of the individual projects or analyzed scenarios resulted in a positive NPV. Inclusion of NOS revenues where service is provided from existing ATC (no new facilities required) results in slightly positive NPV for two scenarios—WOMR/West of Garrison and WOMR/Little Goose.

The following figure shows NPV results by project and for project consolidation:



	WOMR	I-5	Little Goose	WOMR & West of Garrison	Harney County	Northern Intertie	WOMR & LaGrande	WOMR & I-5	Alternative 3_WOMR & Little Goose &	Alternative 4_WOMR, Little Goose, WOG	Alternative 2_Consolidated (All Projects)	Consolidated Less Harney	Consolidated Less Harney & N. Inter.	Consolidated Less Harney, N. Inter. & I-5
No Authorized MWs	(118,377)	(266,790)	(66,508)	(110,488)	(213,607)	(170,015)	(243,863)	(336,956)	(110,201)	(342,465)	(342,465)	(637,942)	(467,926)	(255,962)
With Authorized MWs	-	-	-	72,258	-	-	(61,117)	(154,210)	66,270	(168,856)	(673,112)	(455,196)	(285,180)	(73,216)

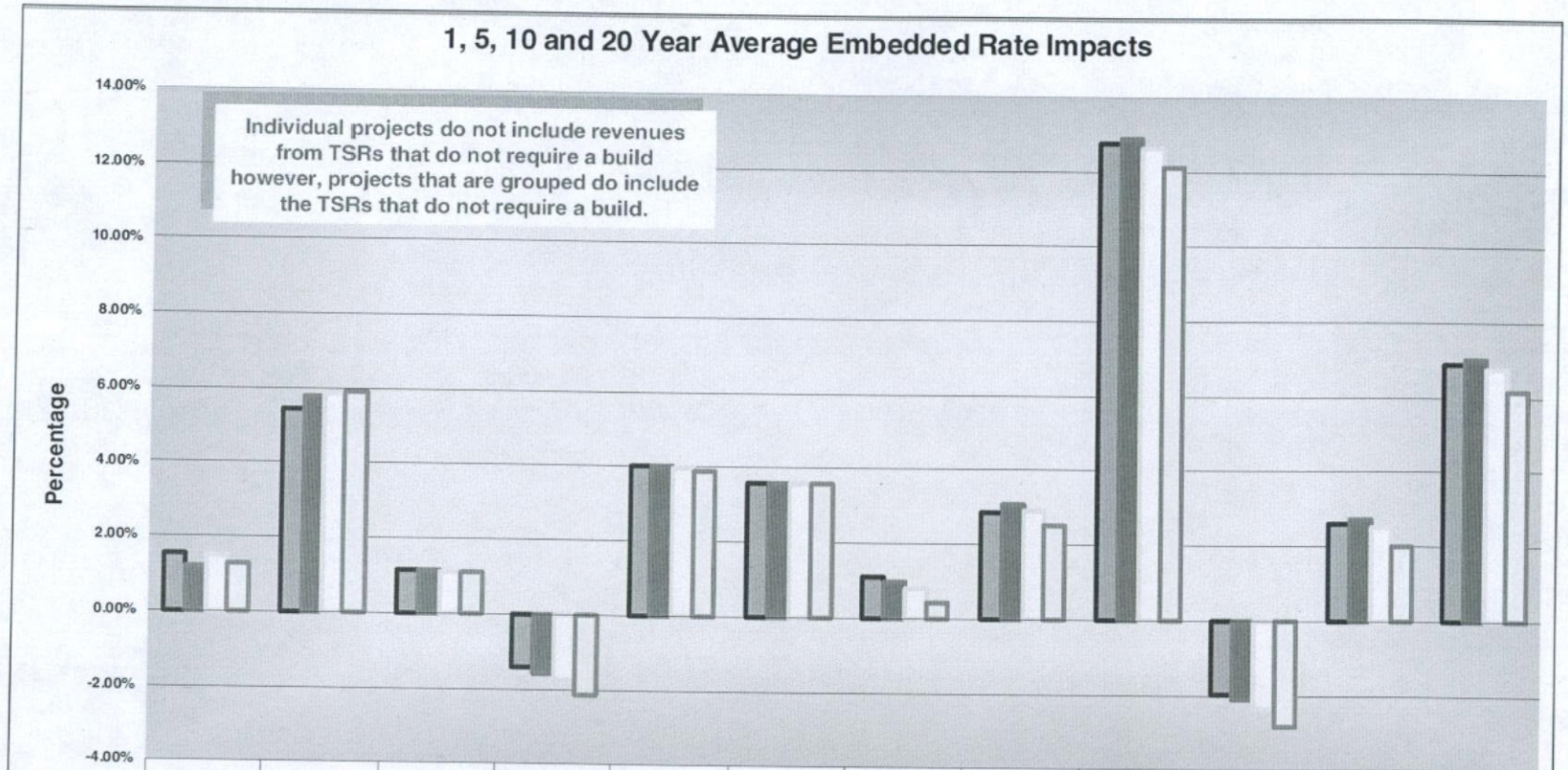
Projects

Note: "With Authorized" refers to requests that can be granted without a capital build and are included in the NPV calculation. "No Authorized" refers to only to the requests that require a capital build.

Rate Impact Analysis Results:

A rate impact analysis was performed for all projects and consolidation of projects. If BPA moved forward with all expansion facilities identified in the Cluster Study, customers would see an average 12 percent rate increase over a 20-year period.

The following figure shows rate impacts by project and project scenarios.



	WOMR	I-5	Little Goose	WOMR & West of Garrison	Harney County	Northern Intertie	WOMR & LaGrande	WOMR & I-5	All projects Requiring Exp Facilities	WOMR, Little Goose, & WOG	WOMR, Little Goose, WOG & I-5	WOMR, Little Goose, WOG, I-5 & Harney
First Yr	1.52%	5.45%	1.14%	-1.44%	4.04%	3.58%	1.11%	2.87%	12.76%	-1.96%	2.59%	6.88%
5 Yr Average	1.21%	5.79%	1.13%	-1.58%	4.01%	3.59%	0.98%	3.06%	12.89%	-2.12%	2.74%	7.00%
10 Yr Average	1.51%	5.85%	1.12%	-1.78%	3.98%	3.59%	0.80%	2.90%	12.65%	-2.36%	2.52%	6.75%
20 Yr Average	1.29%	5.91%	1.11%	-2.16%	3.91%	3.61%	0.44%	2.52%	12.11%	-2.85%	2.02%	6.18%

Regional Economic Analysis
Regional economic analysis was conducted using a production/cost methodology to identify northwest regional economic benefits and effects due to the addition of all generation identified in the 2008 NOS (approximately 4,600 MW, mostly renewables) and associated transmission facilities. Section 8 of this ADF includes key results of this analysis.

Preliminary Customer Comments
See appendix summarizing customer comments below.

5) Decision Evaluation Criteria:

A number of criteria have been identified and applied in the evaluation of the alternatives:

Business/Finance

a) Cost effectiveness using NPV analysis consistent with the CIFP analysis process and Agency financial assumptions;
b) No more than a 2-3% rate impact for the combined expansion facilities over 20 years;
c) Negligible to low stranded investment risk;
d) Consistency with BPA's financial targets, rate case assumptions, and treasury payment probability;
e) Acceptable impact on future capital adequacy;
f) Can be financed using third-party lease program;
g) No adverse impact on BPA's bond rating;
h) Enhanced system operation by reducing reliance on curtailment calculators and remedial action schemes;
i) Reliability benefits;
j) Provide capacity for load growth and future commercial sales;
k) Impact to future non-firm revenue;

Legal:

a) Consistent with applicable statutes, BPA Tariff, and PTSA terms.
b) Legal issues and potential legal risks associated with recommendations fully understood and mitigated to the extent possible.

Environment:

a) Impact on the environment is considered. Decision to construct any facilities is subject to NEPA review.
b) Recommendations not in conflict with fish and wildlife goals, energy efficiency goals, renewable resource development, and climate change response policy.

Public Interest:

a) Customers, merchants, transmission providers, elected officials, other stakeholders and media perspectives understood and taken into account.
b) Provide enhanced ability for region to meet Renewable Portfolio Standards;
c) Provide for wind diversity;
d) Provide regional benefits to customers and consumers in the BPA balancing authority and western interconnection.

BPA's People and Processes:

a) Demonstrated ability to carry out work necessary to complete NEPA and to construct projects in accordance with the capital program.
b) Acceptable impact on BPA people and culture objectives;
c) Supports Agency workforce/workplace goals for leadership, talent, motivation/alignment and positive work environment:
d) Recommendation consistent with BPA internal policies, procedures, and internal controls.

6) Key Risks:

EXECUTION RISK

a) **BPA may be unable to complete NEPA review or offer conditional firm service within 36 months of the rolled-in rate determination as required by the PTSA. A customer has the right to terminate its PTSA in this circumstance, which could alter the assumptions upon which the rolled-in rate determination was based. There is MODERATE to HIGH risk that NEPA will not be completed in 36 months of the rolled-in rate determination, and a low to moderate probability that at least one customer may terminate its PTSA for BPA's failure to complete NEPA on schedule.**
   - Mitigation: I-5 has an estimated 36 to 48-month NEPA timeline. It may be possible to amend the PTSA once BPA determines the NEPA schedule.

b) **Commodity and construction costs could increase, resulting in a rate impact higher than anticipated. This is a MODERATE risk with a low probability that the rate impact will be significantly higher.**
   - Mitigation: Estimates include low to high confidence adjustments based on plan of service (high confidence=10% margin; moderate confidence=25% margin; low confidence=50% margin. There is some likelihood that with declining commodity prices, project costs could be overstated. Sensitivity analysis shows less than a one percent rate impact for 50 percent cost overrun.

c) **BPA will have significant sunk costs for NEPA review and preliminary engineering and design required to complete NEPA if BPA decides not to go forward with construction once NEPA review begins, because these costs will be expensed. There is MODERATE risk that at least one of the proposed projects will not proceed on the proposed schedule, resulting in sunk costs.** NEPA work has a limited shelf life before it must be revisited. Mitigation: None. This is a cost that all BPA ratepayers bear that is not unique to NOS. NEPA cost for the recommended alternative (Alternative 4) is estimated at $16 million.

d) **Customers holding PTSAs could default which would impact future revenues. Security held by BPA is not sufficient to fully protect BPA ratepayers from rate impacts due to default. There is moderate risk for increased rate impact with high probability that at least one customer may default.**
   - Mitigation: The amount of risk BPA ratepayers will bear is unique to each project, the number of customers that will take service over the projects, and the long-term financial viability of the participating customers. Some projects enable service for multiple customers over critical paths required for load service. Other projects are for service to a single customer connecting new generation to the network. Sensitivity analysis shows that a 15 percent loss of revenue due to default by customers would result in a rate impact of 5.7 percent.

e) **BPA cost of third-party capital could increase causing unanticipated upward rate pressure. There is MODERATE risk that an increase in capital costs will lead to upward rate pressure with a low probability that BPA will be unable to mitigate the impact.**

- Mitigation: The master lease program is set up to help minimize these effects. Treasury borrowing could be an alternative for some portion of the capital requirement.

f) **Cluster study planning analysis could include inaccurate assumptions, resulting in flawed identification of expansion facilities needed to enable service. Projects may not provide sufficient capacity to enable service. There is a LOW to moderate risk that the plans of service are inadequate for with a low probability that service cannot be enabled.**
   - Mitigation: External review by Columbia Grid and NTTG has confirmed that plans of service are electrically feasible, do not result in adverse consequences for the western interconnection, and will provide sufficient capacity to enable service.

g) **Major unanticipated changes in interconnected system topology, load, and generator dispatch patterns could significantly alter Cluster Study results. There is LOW risk that the topology and other changes will occur, and a low overall probability that this will occur.**
   - Mitigation: Planning will continue to conduct sensitivity analyses to evaluate risks that could alter flows and plans of service.

h) **External policies for conditional firm, reliability, and ATC could impact the way existing network facilities are managed, the availability of ATC, and the need and timing for proposed projects. There is LOW risk and low probability that policy changes will result in changes to the plans of service.**
   - Mitigation: BPA is an active participant in FERC, NERC, and WECC efforts to define new reliability and commercial rules for transmission management. While changes in criteria and process are inevitable, TS does not believe that any such changes will result in significant modification to the Cluster Study results.

i) **Customers may not roll over service at the end of their contract term, reducing the total revenue assumed in the determination of NPV and rate impact. The base case analysis assumes that all contracts with duration of five years or longer will roll over. There is LOW risk and moderate probability that one or more customers will choose not to roll over their contract at the end of the contract term.**
   - Mitigation: A significant portion of the requested transmission service is associated with the interconnection of new generators. This increases the likelihood that transmission service will be acquired at least for the life of the generating facility. The average duration for all PTSA commitments is thirteen years. Sensitivity analysis has been conducted to evaluate impact on revenue that would result from reduced rollovers.

j) **Customers may elect to defer their service commencement date (start date) for up to five years. If the customer defers the commencement of service, BPA will extend the contract end date and the customer must still purchase transmission service for the full requested service duration. Deferral delays when revenues are received. There is LOW risk that deferrals will affect rates, and a high probability that this will occur.** Sensitivity analysis has been conducted to evaluate the NPV and rate impact under circumstance where all PTSA are deferred for 5 years (worst case outcome). The rate impact is negligible (approximately 0.2 percent over 20 years).
   - Mitigation: None.

7) Alternatives Considered:

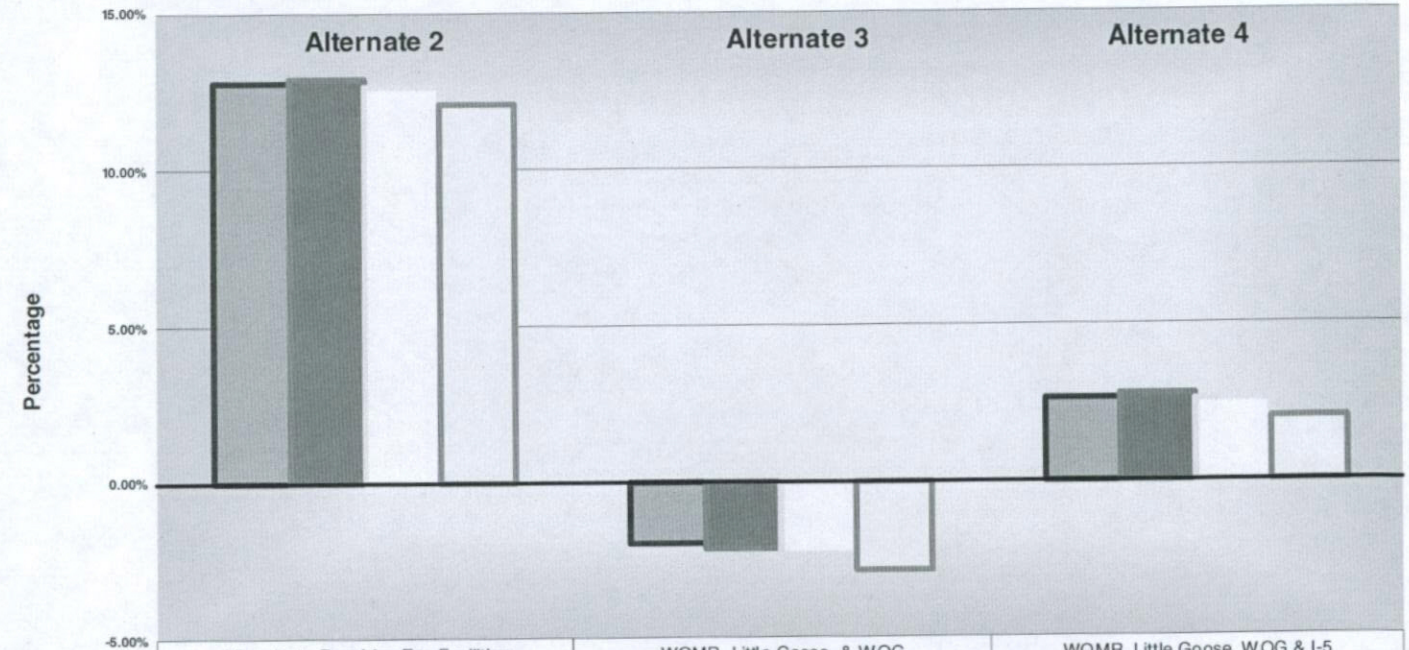
I. Alternative #1: Do not move forward with any of the required expansion facilities at rolled-in rates, and notify customers that BPA is terminating all signed PTSAs and will process their TSRs in accordance with the Tariff.

II. Alternative #2: Move ahead with NEPA work for all required expansion facilities as BPA has "reasonably determined" that it can provide service for all PTSAs under the PTP or NT rate.

III. Alternative #3: Move ahead with NEPA for WOMR, Little Goose and West of Garrison expansion facilities, and notify customers whose service would be enabled by these projects that BPA has determined that service can "reasonably be provided" under the PTP or NT rate. In addition, notify all other customers that that expansion facilities required to enable service cannot be provided at the rolled-in rate, that the PTSA will terminate, and that BPA will process their TSRs in accordance with the Tariff.

IV. Alternative #4: Move ahead with NEPA for WOMR, Little Goose, West of Garrison, and I-5 facilities, and notify customers whose service would be enabled by these projects that BPA has determined that service can "reasonably be provided" under the PTP or NT rate. In addition, notify all other customers that expansion facilities required to enable service cannot be provided at the rolled-in rate, that the PTSA will terminate, and that BPA will process their TSRs in accordance with the Tariff.

The following figure is a summary of rate impacts for the alternatives considered in this ADF:



	All projects Requiring Exp Facilities	WOMR, Little Goose, & WOG	WOMR, Little Goose, WOG & I-5
First Yr	12.76%	-1.96%	2.59%
5 Yr Average	12.89%	-2.12%	2.74%
10 Yr Average	12.65%	-2.36%	2.52%
20 Yr Average	12.11%	-2.85%	2.02%

Projects

8) Analysis of Alternatives:

The following analysis is based on the criteria outlined in Section 5 above. Refer to Section 5 for full explanation of each item.

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
Business/Finance				
a) NPV	NPV is not applicable	Negative NPV of $856 million	Negative NPV of $116 million (does not include West of Garrison)	Negative NPV of $351 million
b) No more than 2-3% rate impact	No rate impact	Rate impact over 20 years is a 12.1%increase. The rate impact excluding the requests included in the revenue requirement in the TR-10 Rate Case would be a 14.7% increase.	Rate impact over 20 years is a 2.6% decrease. The rate impact excluding the requests included in revenue requirement in the TR-10 Rate Case would be 0.4% decrease.	Rate impact over 20 years is a 1.5% increase. The rate impact excluding the requests included in revenue requirement in the TR-10 Rate Case would be 4% rate increase.
c) Stranded investment risk	None	Some projects (Harney and Little Goose) carry risk.	Some risk with Little Goose	Some risk with Little Goose
d) Consistent with Financial plan, targets and rate case.	WOMR and I-5 were included in the rate case and the financial plan. If we do not proceed with these projects, it would be inconsistent with the financial plan.	WOMR and I-5 were included in the rate case and the financial plan. If we proceed with all of the projects, the expansion costs would be significantly higher than planned in the targets and financial plan. There would be no affect on the rate case assumptions because none of these projects are expected to be in service during the FY10-11 rate period.	WOMR and I-5 were included in the rate case and the financial plan. If we do WOMR, Little Goose, and West of Garrison, there would be some impact to the financial plan and targets. There would be no affect on the rate case assumptions because none of these projects are expected to be in service during the rate period.	WOMR and I-5 were included in the rate case and the financial plan. If we proceed with WOMR, Little Goose, West of Garrison, and I-5 there would be some impact to the targets and financial plan. There would be no affect on the rate case assumptions because none of these projects are expected to be in service during the rate period.

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
e) Capital adequacy	None	Would not have significant impact on capital access until all projects proceed. Defers a capital access solution. Proceeding with all projects presents significant concerns for capital access.	Has a neutral impact on borrowing authority compared to the 2010 OMB Budget Submission.	Stretches capital access beyond that anticipated in the 2010 OMB Budget Submission.
f) Third party lease		Not until the projects proceed to start construction and incur financing costs. If projects do not proceed, NEPA costs will be expensed.	Yes, third party lease is viable.	Yes, third party lease is viable.
g) BPA bond rating		No impact until plan to proceed with all projects – then likely negative impact	Likely no impact	Some concern, but likely no impact
h) Redispatch, Curtailment & RAS	Non-Firm and Firm curtailments on network likely to increase. Continued reliance on RAS	Initial reduction to Non-Firm curtailments on network likely to continue due to an increased set of firm obligations from PTSA. Continued reliance on RAS	Initial reduction to Non-firm curtailments on network likely to continue due to increased firm obligations from PTSA. Continued reliance on RAS	Initial reduction to Non-firm curtailments on network likely to continue due to increased firm obligations from PTSA. Continued reliance on RAS

Agency Decision Framework Analysis – 2008 Network Open Season

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
i) Reliability benefits	Does not improve reliability	The present value benefits associated with a delay of non-NOS capital projects is $13.5 million. If we build Big Eddy - Station Z (part of WOMR) then we would delay the following project from 2015 to 2018: • Station K (Pine Grove) and 3 series capacitors on Marion lines. Approximate estimated cost is $110 million, which is a $10 million PV benefit. If we build I-5, we will delay the following project from 2015 to 2020: • Line Reconductoring of Olympia-Chehalis, Chehalis-Longview tap #1 & #3 and Longview tap to Longview. Approximate estimated cost $20 million, which is a $3.5 million PV benefit.	The present value benefits associated with a delay of non-NOS capital projects is $10 million: If we build Big Eddy - Station Z (part of WOMR) then we would delay the following project from 2015 to 2018: • Station K (Pine Grove) and 3 series capacitors on Marion lines. Approximate estimated cost is $110 million, which is a $10 million PV benefit.	The present value benefits associated with a delay of non-NOS capital projects is $13.5 million. If we build Big Eddy - Station Z (part of WOMR) then we would delay the following project from 2015 to 2018: • Station K (Pine Grove) and 3 series capacitors on Marion lines. Approximate estimated cost is $110 million, which is a $10 million PV benefit. If we build I-5 we will delay the following project from 2015 to 2020: • Line Reconductoring of Olympia-Chehalis, Chehalis-Longview tap #1 & #3 and Longview tap to Longview. Approximate estimated cost is $20 million, which is a $3.5 million PV benefit.

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
j) Future revenue (from current queue and additional ATC)	Does not enable additional sales	See comments under alternatives 3 and 4.	Based on a preliminary Planning assessment, there are approximately 8 TSRs that were not in the 2008 NOS, with an associated demand of 475 MW that could be enabled by addition of the proposed NOS projects under Alternative #3. This result is based on preliminary analysis of the Pending Queue (from mid-December 2008). Following development of an ATC base case reflecting the NOS projects and PTSAs enabled, a sizable number of additional TSRs would likely be enabled. West of McNary post-NOS ATC = 681 MW West of Slatt post-NOS ATC = 295 MW	South of Allston is currently at 0 ATC. The *de minimis* bucket for this flowgate is also nearing 0 MW. Given the nature of the BPA network, 0 ATC at any one flowgate will limit future sales across the network, not just those primarily using I-5 In addition to the information in alternative 3, planning is conducting further studies to determine the expected ATC from I-5 specific to the South of Allston and Paul-Allston flowgates. The short duration of the current requests (PTSA) for I-5 is why there is a negative NPV in the CIFP analysis. Additionally, the CIFP assumes that they will not roll-over (less than 5 years), however, we assume a high likelihood that they will rollover and that the increased ATC for South of Allston will enable future new service. For example, an initial assessment of the current transmission queue (post-NOS) shows 250 MW that could be enabled by I-5. These and other future use would mitigate rate pressures.
k) Non-firm revenue	Continued impact to delivery of non-firm service along the I-5 corridor.			I-5 would reduce curtailment events impacting loss of service associated with non-firm service.

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
l) Ability to meet RPS requirements	None	Supports	Supports	I-5 does not add any additional support for RPS requirements that is not reflected in Alternative 3.
m) Wind diversity	None	Harney and Little Goose could bring more geographic diversity to the Northwest wind fleet.	Enables Little Goose	Enables Little Goose
n) Regional benefits	Approximately $72 million ($84 million with Harney*) savings in thermal generation cost per year (2.5% savings in total average energy cost per year) starting in year 2015. With no transmission expansion, 20% increase in network flowgate loadings resulting in major congestion across WOM, WOS, WOJD, and South of Allston. However, very limited flowgate limit violations (flows exceeding 100%) noticed. * Harney wind generation would require radial transmission to Malin to access markets. Without the transmission connection, there are no realized benefits of Harney wind.	Additional $10 million (over Alt #1) savings in thermal generation cost per year (3.2% savings in total average energy cost per year) starting in the year 2015. BPA flowgate loading levels reduced substantially (26 hours per year flowgate loadings exceed 90%).	Additional $7 million (over Alt #1) savings in thermal generation cost per year (2.6% savings in total average energy cost per year) starting in the year 2015. BPA flowgate loading levels exceed the 90% loading levels for 577 hours; 528 hours on the I-5 flowgates.	Additional $8 million (over Alt #1) savings in thermal generation cost per year (2.7% savings in total average energy cost per year) starting in the year 2015. Alternative 4 removes 80% of the flowgate loadings that exceeded 75% of the flowgate limits as compared to Alternative 1. I-5 reinforcement does provide for additional flow reduction across Paul-Allston and South of Allston. Three hours of flowgate loadings exceeded 90% as compared with 528 hours in Alternative 3
o) Power Loss benefits (regional benefit)			42 MW per year which results in a regional benefit of $13.9 million.	62 MW per year which results in a regional benefit of $16.7 million.
Legal				

Agency Decision Framework Analysis – 2008 Network Open Season

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
a) [Ex 5]	[Ex 5]	[Ex 5]	[Ex 5]	[Ex 5]
Environment				

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
a) Environmental impact	None	Plans of service for projects other than those in Alternatives 3 and 4 have not been fully analyzed at this point. For recommended projects, please refer to comments under Alternatives 3 and 4.	For WOMR, some of the potential issues, in addition to cultural resources, include locating new right-of-way through rural-residential land including tribal allotment lands and the Columbia Gorge Scenic Area (CGSA) for Big Eddy-Substation Z. For purchasing new right-of-way in the CGSA two conditions must be met, (1) there are no alternatives, and (2) the project is as large as it needs to be. KEC does not anticipate any major issues with McNary-John Day. For Little Goose, a major issue should be locating the line to minimize impacts to agricultural interests as much as possible. KEC doesn't anticipate any issues with the West of Garrison RAS.	For I-5, much new right-of-way would be needed through rural and urban lands. Although the alternatives have not been identified, threatened and endangered species would be expected to be a major issue in locating any line between Castle Rock and the Pearl Substation. KEC expects multi-year surveys to be required for murrelet and the spotted owl, and there may be others. In addition, locating a new line through vineyard land in Yamhill and Washington counties will raise issues.
b) Aligns with environmental policies	Not applicable	Promotes new areas of wind development (specifically Harney, Little Goose, WOMR)	Does not include Harney, which could potentially be a new area of wind development.	Does not include Harney, which could potentially be a new area of wind development.
Public Interests				

Agency Decision Framework Analysis – 2008 Network Open Season

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
a) General Public	If we do not proceed with any of these projects, BPA could be perceived as not supporting wind development in the region through interconnections (WOMR, I-5)	BPA will be seen as actively pursuing investment in infrastructure, but will likely be criticized for over spending. Given the obvious positive and potentially negative impacts early engagement of media in Portland, OR and Vancouver, WA is a must.	BPA will be seen to support wind in the region and still remain a cost-conscious government agency.	BPA will be seen to support wind in the region and still remain a cost-conscious government agency. Media could show BPA as an agent of economic development in these difficult years. Could also see EMF or other potential project impacts emerge in media as well. Because we might be turning dirt and putting steel and conductor in some densely populated Portland, OR and Vancouver, WA areas, early introduction of the I-5 project via the media is important.
b) Landowners	May see pushback from landowners who would have had wind turbines on their property (WOMR).	Massive number of landowners will be impacted and involvement with realty and public affairs staff will increase.	Few landowners will be impacted by construction, many support WOMR.	Large number of potential landowners along I-5 would be engaged, some may silently support; others may fight against property, visual, EMF or other impacts. There would be severe landowner challenges with I-5 if we keep western route alternatives on the table.

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
c) Customers (see comments in section 5)	Not supported. Customers strongly encouraged BPA to develop transmission infrastructure to meet load growth, allow for a diversified portfolio of new resources, support meeting RPS requirements, and reduce network congestion. NOS Customers indicate that they will accept transmission rate increases, consistent with average rate increases over the past 10 years (approximately 2% per year); to assure the transmission system is adequate.	Not supported	Supported, however, public power wants LaGrande project as well.	Supported however, public power wants LaGrande project as well.
d) Environmental Advocates	Reaction could be mixed, some will be neutral as we will not negatively impact wildlife, land, etc., but others may argue that BPA is not supporting the wind projects that need these facilities to interconnect.	Mixed reactions anticipated, we would not know which advocacy groups would not support until environmental review is underway and alternatives are identified. Could be environmental opposition to Harney.	Some support, some criticism as with alternative #2.	Some support, some criticism as with alternative #2. Environmental advocates may raise fish concerns for I-5.

Agency Decision Framework Analysis – 2008 Network Open Season

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
e) Tribal	Mixed reaction among tribes. Potential land disturbances during construction that may negatively affect cultural resources or traditional cultural properties will be avoided. May face criticism from tribes pursuing renewable wind energy development.	Reactions vary among tribes. Wind integration perceived to help relieve river operations, support tribal renewable energy development. Potential land disturbances during construction may negatively affect cultural resources or traditional cultural properties. Concerns over effects on birds. Will increase tribal affairs involvement.	Mixed reactions, see alternative #2.	Mixed reactions, see alternative #2.
f) Administration DOE/OMB	Not proceeding would be inconsistent with federal stimulus package and national energy policy	Likely large support if we can demonstrate regional job impact as well as enabling green energy.	Likely large support if we can demonstrate regional job impact as well as enabling green energy.	Likely large support if we can demonstrate regional job impact as well as enabling green energy.
g) Congress	High degree of interest in meeting our NOS timeline as evidence of support for renewables	Premature to gauge support/opposition for specific projects, but we will need to conduct substantial outreach.	Premature to gauge support/opposition for specific projects, but we will need to conduct substantial outreach. Need to be sure all major projects are in the federal budget. Likely happy to see the infrastructure investment as a concept, but local opposition on specific routes could turn representatives.	Need to be sure all major projects are in the federal budget. Likely happy to see the infrastructure investment as a concept, but local opposition on specific routes could turn representatives.
h) Treasury	N/A	Would have concerns about major third party financing initiative for $1.5 billion.	Does not like non-Treasury financing, so not likely to look favorably on these projects.	Does not like non-Treasury financing, so not likely to look favorably on these projects.

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
i) Rating Agencies	N/A	May appreciate that we will not take action until we know more about environmental exposure.	May have some concern about magnitude of third party financing.	May have some concern about magnitude of third party financing.
BPA's People and Processes				
a) Manageable workload	Not applicable	Significant workload impact. New resources required. Public Affairs will require new resources to handle outreach to region, landowners, etc. See alternatives 3 & 4 for additional project impacts to workload.	Manageable workload impact. For the McNary-John Day portion of WOMR, TEP already has an initial plan for materials and construction if the decision is made to proceed.	I-5 is a 6-7 year project and adds significant workload and may stress BPA capabilities. I-5 construction would not begin until WOMR completion. NEPA is three plus years at the start which provides time to determine the plan of action for materials and construction in the later years. TEP is considering doing more by contract in the NEPA and preliminary design phase. TEP will review the overall plan, and will consider other ways of managing this project. TEP is confident in its ability to execute to schedule and within budget. Public Affairs will require new resources to handle outreach to region, landowners, etc.
b) Impact to BPA culture				BPA will assess the necessary work to prepare for a project that has significant political & social ramifications.

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
c) Agency workforce goals		May impact other projects for 2009 by displacing priority assignments for key subject matter experts. BPA needs to assess its ability to secure supplemental labor where human capital shortfalls may exist.	BPA needs to assess its ability to secure supplemental labor where human capital shortfalls may exist.	May impact other projects for 2009 by displacing priority assignments by key subject matter experts. BPA needs to assess its ability to secure supplemental labor where human capital shortfalls may exist.
d) Consistent with internal policies	Yes	Yes	Yes	Yes

Financial Sensitivity Analysis:

- In the NOS analysis we looked at all the TSRs that were enabled due to the NOS process. The revenue associated with these TSRs enabled through the NOS process allowed Transmission Services to offer the region no rate increase for FY 2010-11.
- In addition there were several other sensitivities performed using the following assumptions:
  - Deferrals: Assume all PTSAs exercise the right to extend their commencement of service date five years.
  - Rollover: Assume all of the PTSAs do not roll over their contract. The term requested was modeled and there was no assumption to extend their contract.
  - Default: Assume 15% of the wind requests default and do not start their service.
  - Project Cost Increase: Assume the project costs will increase based on the confidence level that was identified by planning. High confidence level assumes no cost increase, Medium confidence level assumes a 25% cost increase and Low confidence level assumes a 50% cost increase.
  - Project Cost Decrease: Assume the all project costs will decrease by 10%.

The following table shows the rate impact with the above assumptions:

20 yr Variances

	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Deferrals	N/A	0.22%	0.19%	0.17%
Rollover	N/A	7.28%	5.11%	6.76%
Default	N/A	1.42%	0.88%	1.09%
Project Cost Increase	N/A	1.20%	0.13%	0.31%
Project Cost Decrease	N/A	-0.35%	-0.06%	-0.14%

In addition to the alternatives, we ran a sensitivity including Harney with alternative #4. The result was a 6.2% rate impact compared to the 2.2% rate impact for alternative #4.

9) Recommendation:

Transmission Services is proposing Alternative 4 and requesting that the CAB approve funding for NEPA, preliminary engineering and design for the West of McNary Reinforcements (McNary-John Day and Big Eddy- Station Z), I-5 Reinforcement, Little Goose Reinforcement and the West of Garrison RAS for the following reasons:

- Alternative 4 would result in average rate pressure 1.5 to 2 percent—within the range that appears acceptable to customers.
- Alternative 4 enables service to 15 customers holding 74 PTSAs for a total of 3,699 MW.
- With the previously authorized service under NOS (using existing ATC) combined with Alternative 4, only four customers (CEP, Powerex, Horizon and PNGC), holding 33 PTSAs for 929 MW would not receive service at the rolled-in rate and under the 2008 NOS (Powerex and Horizon will receive some service through recommended projects). On a MW basis, approximately 85 percent of the TSRs for which PTSAs were signed in 2008 NOS will be enabled if BPA decides following NEPA to proceed with construction.
- Plans of service are sufficiently advanced for McNary-John Day, Big Eddy-Station Z, Little Goose and I-5 to have medium to high confidence in the cost estimates. While confidence in the West of Garrison RAS cost estimate is low, the total cost is not expected to exceed $2 million. Cost variance on this project may be high on a percentage basis, but on an absolute basis, there is low potential for big, unexpected cost impacts.
- NEPA review and Preliminary Engineering for the McNary-John Day project was completed in 2002 and are being reevaluated to determine if a supplemental draft Environmental Impact Statement analysis is necessary. NEPA and Preliminary Engineering for Big Eddy-Station Z are estimated to take 24 months and cost $6 million. NEPA and Preliminary Engineering for I-5 are estimated to take from 36 to 48 months to complete and cost approximately $14 million. NEPA and Preliminary Engineering for Little Goose Reinforcement would likely take 18 months to complete and cost $6.5 million. WOG RAS environmental review is expected to be minimal. The environmental review for WOG RAS will be packaged as a categorical exclusion.

- Little Goose expansion facilities will allow wind development to shift further east, potentially resulting in diversification of the wind fleet and a reduction in the balancing reserve requirement provided by the federal system.
- The WOMR, Little Goose and I-5 projects will result in additional capacity for future load growth and commercial use beyond what is required to enable service under the PTSA. West of McNary will result in 681 MW and West of Slatt will result in 295 MW of ATC.
- Alternative 4 carries minimal risk of stranded investment as service would be enabled for a large and diverse customer base (15 customers, 74 PTSA for 3,699 MW).
- Plans of service for WOMR, I-5 and Little Goose have been reviewed and endorsed by Columbia Grid.
- Economic modeling shows Northwest regional benefits of approximately $8 million annually starting in the year 2015 due to better fuel utilization and reduced curtailments (Appendix II)
    - Based on the reduction of hours of congestion across BPA flowgates, the added O&M flexibility resulting from new transmission, and due to the likely increase of additional renewable resources to meet state RPS requirements, **the analysis recommends the proposed WOMR (McNary-JD, Big Eddy-Station Z), I-5, and Little Goose reinforcements**.

*Summary of PTSA enabled by recommendation by customer by project (** indicates a partial offer that splits a PTSA):*

WOMR	45 PTSA	2,023 MW**
PPM Energy	8	200 MW
Pacificorp	1	38 MW
PBL – NT	3	176 MW
PPL EnergyPlus, LLC (EPLU)	1	50 MW
Lewis County PUD – NT	1	21 MW
Puget Sound Energy	1	27 MW
Wind Power Associates, LLC	3	60 MW
Snohomish	2	100 MW
Horizon Wind Energy, LLC	18	912 MW
PPM Energy	1	50 MW
enXco Development Corp	6	400 MW
Little Goose	5 PTSA	200 MW
Puget Sound Energy	5	200 MW
WOMR & Little Goose	12 PTSA	640 MW
Puget Sound Energy	4	150 MW
PBL – Redirect	1	90 MW
PPM Energy	4	200 MW
Renewable Energy Systems	4	200 MW
WOMR & West of Garrison RAS	1 PTSA	91 MW**
Alternity Wind Power	1	80 MW

I-5	2 PTSA	150 MW
TransAlta Energy Marketing	2	150 MW
WOMR & I-5	7 PTSA	495 MW
PPM Energy	1	45 MW
Powerex	2	200 MW
TransAlta Energy Marketing	3	250 MW
WOMR & I-5 & Little Goose	2 PTSA	100 MW
PPM Energy	2	100 MW

Summary of direct costs by project:

1. WOMR = $362 million
2. Little Goose Reinforcement = $99 million
3. I-5 = $342 million
4. West of Garrison RAS = $2.3 million

Summary of timeline and costs associated with NEPA and preliminary engineering work for proposed projects (West of Garrison should entail minimal NEPA work):

Project	**2009**	**2010**	**2011**	**2012**
Big Eddy-Station Z	$1,200,000	$3,800,000	$1,000,000	
Little Goose	$800,000	$3,200,000	$2,500,000	
I-5	$1,500,000	$6,000,000	$4,000,000	$2,500,000
Total = $26,500,000	$3,500.000	$13,000,000	$7,500,000	$2,500,000

Reasons for Not Proposing Alternative 2:

- An average rate increase of approximately 12 percent over 20 years would be required if BPA were to proceed with expansion facilities necessary to enable service to all customers holding a PTSA.
- BPA may not have the financial or staffing resources or the capability to simultaneously carry out (over five to six years) a program of this magnitude.
- Certain projects have unique characteristics and risks that have a direct bearing on whether it is prudent for BPA and its customers to proceed with NEPA expenditures at this time:
    - Harney Area Reinforcement: Based on data and comments supplied by CEP, the Harney project could open up a potential new wind development area for the region; however, the plan of service for this 179 mile, 500 kV transmission line provides few additional benefits. PTSA agreements that would be enabled are held by a single customer. In spite of the production cost and diversity benefits, the rate impacts on other customers are above an acceptable level. The plan of service for this expansion project is conceptual and cost estimate reliability is low. A sensitivity analysis was performed to look at the rate impact from

Harney project by including it in Alternative #4. The resulting rate impact was 6.18% (over 20 years) which is likely outside the acceptable range.

- La Grande Area Reinforcement: This path is important for providing west to east transfer service to BPA customers in the Idaho Power Co. and potentially the PacifiCorp east balancing authorities. As BPA customer loads continue to grow in these areas facility expansion or other arrangements will be necessary to serve this load growth. Increasing capacity on the NW to Idaho path will require joint effort by the transmission owners on this path—Idaho Power, PacifiCorp, Avista and BPA. The La Grande area reinforcement would enable service to two customers, PNGC and Horizon Wind. These commitments are not sufficient in themselves to support inclusion of this project as part of this recommendation. Idaho Power and PacifiCorp are jointly planning a major new transmission project that will substantially increase capacity on the NW to Idaho path. BPA is evaluating whether it should purchase capacity in order to meet future needs of its customer. To the extent that new facilities or other arrangements are necessary for the Agency to meet its obligations to provide transfer service to its customers served over this path, BPA will undertake these arrangements as part of its obligation to it transfer service customers outside of an NOS construct.
  One proposal that may satisfy Public Power (Idaho transfer customers) may be to commit to an Agency study that would look at the full range of solutions---buying generation in Idaho, purchasing capacity on the Gateway project if and when built, purchasing capacity on a long-term or short-term basis from other transmission providers and building La Grande as part of a project with Idaho. A plan of action (process and timeline) to conduct a needs assessment and identify alternatives will be completed over a six-month period in a public process.
- Northern Intertie Reinforcement: This path is important for bi-directional transfers between the Canada and the US. Seasonal constraints on this path periodically require active management resulting in curtailments. PTSA commitments received in the 2008 NOS process (100 MW) are not sufficient to warrant moving forward with expansion of the Northern Intertie at this time. Plan of service for this expansion is complex and not fully developed resulting in low confidence in cost estimates. Estimated rate impact for this project averages approximately 3.6 percent over 20 years. In order to fully realize benefits from this project, the I-5 expansion is necessary.

Reasons for including I-5:

- I-5 enables additional transmission revenue when added to WOMR, Little Goose and West of Garrison (585 MW were used for the CIFP analysis).
- Regional economic analysis shows that an additional $1 million per year savings in thermal generation cost.
- I-5 will result in reduced congestion on South of Allston and Paul-Allston of 525 hours compared to Alternative 3.
- I-5 will result in additional power loss benefits of $2.8 million per year (additional 20 MW). This result is in addition to the benefits realized in Alternative 3.

10) Document & Communicate Final Decision:

Proposed decision will be submitted to customers for review and comment. Comments received will be presented to decision makers for final decision. Final decision will be communicated to PTSA contract holders by letter no later than February 13, 2009. A communication plan, internal talking points and notice of final decision will be prepared for distribution.

APPENDIX I

Customer Comments – Informal comments received prior to the public disclosure (Jan. 15, 2009) of the BPA recommendation

- Mike Raschio (representing various clients)
  - Use incremental overhead for rate impact analysis. Using 23% overstates overhead as overhead is already included in transmission rates
  - Recommends WOMR, Little Goose and I-5 projects for NEPA
  - Recommends that revenue that would result from 50% of the post NOS requests be added to the revenue computation.

- NRU (Geoff Carr)
  - Recommends that La Grande project be included in NOS as this path is critical for transfer service which is an Agency responsibility
  - NRU "would also like to state a modest rate impact that would result from building the NOS projects is acceptable to NRU utilities" with exception of Harney County reinforcement project.

- Columbia Energy Partners (Peter Blood)
  - Must factor in synergies and efficiencies posed by Harney County project
  - Harney plan of service needs to be more fully vetted
  - Benefit resulting from CEP commitment to 30 year service duration needs to be included. In addition benefits must be factored into the analysis (reliability, diversity, flow gate relief, location, future uses, enablement of new wind area)
  - Add criterion for wind diversity and alternative plans of service.

- PNGC (Aleka Scott)
  - The La Grande interface is critical to load service to transfer customers in Idaho Power's balancing authority. Firm service to transfer loads is an agency responsibility that needs to be factored into any construction plans for additional or upgraded transmission. BPA's service to the customers in the Idaho Power balancing authority is already difficult. BPA should also work with Idaho Power to ensure firm service to transfer loads on the Idaho Power system.
  - PNGC Power would be willing to accept a modest embedded cost rate increase from building certain NOS projects. With the exception of the Northern Intertie project and the Harney project.
  - BPA's analysis shows that the remaining NOS projects would provide a robust transmission system at a modest embedded cost increase. BPA should not limit itself to zero embedded cost rate increase when considering which NOS projects to move forward under a rolled-in rate regime.

- Western Montana G&T (Bill Drummond)
  - Supports inclusion of the La Grande project identified in the NOS process as part of the package of transmission upgrades that is recommended to the Administrator. The La Grande interface is critical to load service to Bonneville transfer customers in Idaho Power's Balancing Authority. Firm service to transfer loads is a Bonneville obligation that needs to be included into any construction plans for additional or upgraded transmission. The transmission service requests served by the La Grande upgrade should be served at embedded rates and not subject to an incremental rate.
  - Several WMG&T members rely on transfer service and it is important to maintain access to Bonneville power over a non-federal transmission owner's facilities. We recognize that the La Grande project will not likely directly benefit us and may result in a slightly higher Bonneville transmission rate. We are willing to accept that consequence, however, because we support the principle that new or upgraded federal facilities necessary to serve transfer customers are part of the federal backbone transmission system and therefore should be charged at embedded cost and not incremental rates.

APPENDIX I (continued)

Customer Comments – Formal comments received during the public comment period (Jan. 15-30, 2009) on BPA's recommendation

- Snohomish PUD (Linda Finley)
  - Suggests a longer-term forward look to assess future load growth and benefits in the analysis
  - Modify Deposit of Escrow language so it works for Washington PUDs
  - Reconsider Monroe Echo Lake (Northern Intertie). Are there smaller projects that would meet the needs?
  - Be clear on how NOS 2009 will build on NOS 2008 requests

- Seattle City Light (Ray Camacho)
  - Reconsider Monroe Echo Lake (Northern Intertie). Include $12 to $24 Million /year in reliability benefits and reduced congestion
  - Reinforcement of above would reduce cost of replacement power for outages

- Powerex (Karen McDonald)
  - Provide additional information about rational for determining which projects move forward at embedded costs rates
  - Provide NPV for projects that we are not moving forward at embedded costs rates
  - Reconsider Northern Intertie upgrades
  - Be clear about re-evaluation of projects in subsequent open seasons

- Columbia Energy Partners (Peter Blood)
  - Wants a more proactive planning process
  - Wants more transparency in decision criteria and rate impacts
  - One size fits all is unacceptable. Wants special consideration of project benefits
  - NOS timeline too long – do it quicker
  - Dedicate resources to Incremental Rate processes
  - Allow roll-over security between NOS 2008 and NOS 2009
  - Open the books on project costs and how they are determined and the financial analysis for NPV
  - Factor in the diversity of their project and regional RPS needs

- PNGC (Aleka Scott)
  - Support the recommendation for projects at embedded costs rates. Appreciates the further assessment of Le Grande path needs and seeking near-term and long-term solutions

- Iberdrola (Jan Korver)
  - IRI supports BPA's recommendation to provide at embedded rates transmission service enabled by the following upgrades and reinforcements: West of McNary (McNary-John Day and Big Eddy-Station Z), Little Goose Area, West of Garrison (RAS) and I-5 Corridor.

- NRU (Megan Stratman)
  - Supports effort. Will participate in needs assessment of LaGrande upgrades
  - Supports periodic, regular NOS process. Extend NOS 2009 closing to end of June, 2009

- RNP (Cameron Yourkowski)
  - Supports the recommendation for moving recommended projects forward at embedded costs rates.
  - Consider economies of scale when sizing upgrades
  - Look at future needs more closely to inform future need for capacity
  - Supports needs assessment for LaGrande upgrades and evaluating all alternatives
  - Expand CIP analysis to include future non-firm uses, CO2 cost, variable generator diversity benefits
  - Do not terminate PTSA for Incremental Costs projects, keep open the option to keep them in the queue for subsequent NOS efforts

APPENDIX II

Regional Economic Analysis:

- Production Costs (Factors considered):
  - Is there a reduction in future short-run generation costs (production costs) resulting from system operation with the addition of all NOS generation?
  - What is the effect on BPA's internal flowgate loadings with the NOS generation additions?
  - Is there a reduction in production costs and internal flowgate loadings resulting from the addition of new transmission facilities?
- Assumptions:
  - PTSAs not associated with a new generator were assumed to be from an existing generator.
  - The analysis assumes that the Western Interconnection is operated as a 'single-owner' system.
  - Report analyzes a system dispatch based on variable resource costs
    - Variable costs for wind-powered electricity are assumed to be negligible - Dispatch considerations in the analysis do not encompass the need by generators to recover their capital costs, fixed operations and maintenance costs and so on, in their power prices.
  - Path loadings were considered high if there were hours at or above 75% of the path's limit.
    - The analysis assumes all lines and voltage support in service.
    - Under outage conditions which change flows and reduce flowgate limits, the production costs are expected to dramatically increase and the flexibility of hydro re-dispatch diminished.
  - The study assumes a 2002 moderate hydro condition.
- Observations:
  - Approximately $8-$10 million annually in thermal production variable cost savings.
    - Reduced thermal fuel utilization and reduced curtailments.
    - Savings have some stability across the future years (additional wind integration and/or increased thermal fuel cost will increase variable cost savings).
  - Congestion on BPA's network flowgates increases with the new generation requiring re-dispatch (mostly hydro but some thermal generation), but is mitigated by the proposed transmission reinforcements.
    - Proposed reinforcements would reduce congestion during transmission system outages, maintenance outages, and/or with additional renewable generation additions.
    - Proposed reinforcements would facilitate integrating most NOS generation, which is located near the existing transmission and hydro system.
- Conclusions:
  - The energy produced by the new generators will displace high-cost generation, much of which is located outside the Northwest. This makes it difficult to measure net economic impacts in the Northwest
  - Including NOS generation, renewables make up approximately 5.3% of total served energy in the Oregon and Washington.
    - Proposed reinforcements will facilitate delivery of additional renewable generation to Northwest customers, helping them meet Oregon and Washington Renewable Portfolio Standards.
    - Absent reinforcements, added renewables result in increased loadings (and subsequent congestion) on several Northwest paths.
- Recommendations:

- Based on the reduction of hours of congestion across BPA flowgates, the added O&M flexibility resulting from new transmission, and due to the likely increase of additional renewable resources to meet state RPS requirements, **the analysis recommends the proposed WOMR (McNary-JD, Big Eddy-Station Z), I-5, and Little Goose reinforcements**.
- Future NOS studies should consider:
    - the timing of when a price is put on carbon dioxide and how that is reflected in energy prices;
    - how that price impact affects choice of fuel and resource;
    - how the siting of new renewable resources may affect transmission planning;
    - at what level and location of renewable additions is the hydro system's existing re-dispatch capability exceeded, causing significantly higher re-dispatch costs;
    - The effects of smart grid infrastructure and transportation on policies and technologies for transmission planning.

Agency Decision Framework	Alt #1 Do Not Proceed with NEPA for Any Expansion Facilities	Alt #2 Proceed with NEPA for All Required Expansion Facilities	Alt #3 Proceed with NEPA for WOMR, Little Goose and West of Garrison	Alt #4 Proceed with NEPA for WOMR, Little Goose, West of Garrison and I-5
a) Consistency with statutes, tariff & PTSA	Because certain groups of projects show a rate benefit, *i.e.*, WOMR/West of Garrison and WOMR/Little Goose, adopting this alternative instead of building at least those combinations of projects would be inconsistent with the OATT as revised by the NOS filing and with the PTSA. Both those documents obligate BPA to provide service to PTSA customers' TSRs if BPA determines that it can reasonably provide embedded cost service. It would be difficult to justify not proceeding to NEPA for the projects mentioned above when the CIFP projects a rate decrease as a result of building the projects and serving the TSRs enabled by such projects. It could also be argued that such a decision would be inconsistent with direction to provide transmission service under sections 4 and 6 of the Federal Columbia River Transmission System Act and 9(i)(3) of the Northwest Power Act.	The projected 12% rate increase resulting from construction of all projects raises a significant issue about whether BPA followed the OATT and PTSA, which require a reasonable determination that BPA can provide service at embedded cost rates. Given the OATT and PTSA requirement, there would need to be substantial justification outside the NOS process to proceed with such a projected rate increase, and there does not appear to be that justification.	This alternative is completely consistent with the OATT and PTSA requirement of a reasonable determination that service could be provided at embedded cost rates because the CIFP projects a rate decrease with this alternative. This alternative also is consistent with BPA's statutory obligations. A possible risk is that a customer with a TSR that would have been enabled by alternative #4 but not by this alternative could argue that BPA has not properly applied the CIFP allowance for expected future uses, such as RPS requirements and non-firm use of additional capacity on the I-5 corridor. FERC may be receptive to these arguments, but would not have authority to overturn BPA's decision. Those arguments could also be made to the 9th Circuit, since the PTSA requires that we follow the CIFP. If BPA's record at the 9th Circuit was adequate, the 9th Circuit would probably uphold BPA's decision.	This alternative is likely consistent with the OATT and PTSA embedded cost rate determination requirement. BPA identifies good reasons to proceed with this alternative notwithstanding a small projected rate increase. A potentially significant risk with this alternative is a challenge from CEP because of not proceeding with the Harney project. The projected rate decrease of alternative #3 makes it easier to defend against a challenge from CEP. The rate impact model on p. 10 of this ADF shows that the projected rate increase with alternative #4 plus Harney is over 6%. A 6% projected rate increase with inclusion of Harney would likely enable BPA to resist a challenge from Harney.
Environment				