Docket No. UE-991409
Exhibit 508

Response of Public Counsel Witness Jim Lazar
To Data Request of Puget Sound Energy

11) With regard to the testimony of Jim Lazar at page 6, lines 8-16, provide all documents that refer or relate to the potential magnitude of any future carbon tax.

While Mr. Lazar is generally familiar with the concept of carbon taxes, he did no research on the subject for this testimony. Instead he relied on the estimates of carbon taxes included in the testimony, exhibits, and workpapers of Puget and Pacificorp in this proceeding, and examined the higher of these as a sensitivity analysis to his basic analysis. The following are the only documents Mr. Lazar could recall reviewing on the subject of carbon taxes in recent years:

a) Attached is an excerpt from the Northwest Power Planning Council 1996 Plan Update, which uses $10, $25, and $40/ton as "illustrative values commonly cited." Mr. Lazar previously reviewed, but did not retain, copies of the documents cited in the footnotes of this excerpt.

b) Attached are copies of the testimony of Jim Lazar and Kevin Bell before the Oregon Energy Facility Site Evaluation Council on the subject of the proposed Coyote Springs power plant; portions of these address CO2 emissions. These were printed from much earlier word processing files, and formatting has been lost.

Mr. Lazar did not review any other materials addressing CO2 emissions in preparing his testimony.

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 508
ADMIT ☑ W/D ☐ REJECT ☐

Northwest Power in Transition

Opportunities and Risks

Draft Fourth Northwest Conservation and Electric Power Plan

Northwest Power Planning Council

96-5
Adopted on March 13, 1996

- In 1988, the Council specified 44,000 miles of stream reaches as protected areas. These reaches were judged to be unsuitable for siting of hydroelectric generating plants, because of the unavoidable effects on fish and wildlife habitat and migration.
- In the 1991 Power Plan, the Council set the cost-effectiveness cutoff for conservation (the upper limit on the cost of conservation measures judged cost-effective) higher than the avoided direct cost of new fossil-fueled generating plants. The extra margin was included by the Council to reflect the environmental advantages of conservation as a resource, compared to fossil-fueled generation.
- In the 1991 Power Plan, the Council also recommended that the region plan to build gasified coal generating plants if coal generation was chosen. Gasification technology was thought to be marginally higher in direct costs, but the Council judged that its environmental advantages, in addition to its potential for staged development, made it preferable to conventional pulverized-coal generating plants.

Environmental Mitigation in Competitive Electricity Markets

In a world of regulated utility monopolies, the mitigation of environmental effects of electricity production can be addressed by the utility itself. Of course, there are difficulties in measuring environmental effects and reaching agreement between utilities and regulators as to how best to mitigate them. When agreement is reached, however, extra direct costs resulting from environmental mitigation can be spread among customers by the monopoly utility. Nonetheless, even monopoly utilities face some level of competition because some customers can choose other energy forms or alternative locations, so the ability of a utility to pass on environmental mitigation costs is limited.

In a world with increasingly competitive elec tricity markets, the ability to pass on costs will be limited. A utility undertaking environmental mitigation that is not required of its competitors will incur costs its competitors do not incur. Beyond some point, this utility risks losing customers if it must require higher power rates.

It is difficult to predict the net effect of a more competitive electricity market on environmental quality. It is plausible to imagine competition leading to the substitution of more efficient and more environmentally benign natural gas generation for older fossil-fuel fired generation. In such cases, more competitive markets could improve environmental quality. In the near term, competition and low gas prices may result in older, less efficient, less environmentally benign plants being run. The balance between the use of newer versus older plants depends on relative production costs. To the extent that environmental effects are externalities[19] to producers and users in competitive markets, there will be continued reason for concern about the level of attention utilities will pay to these effects.

In a competitive world, the desirable level of environmental mitigation will need to be the responsibility of all competitors. This might be accomplished by regulation of technologies, emission trading, pollutant taxing or other means. Whatever means are used, they will need to be applied equitably across competing energy producers, across competing energy forms and across regulatory jurisdictions.

This will tend to move policy decisions regarding environmental mitigation from the level of individual utilities and state and local regulators to the national or international level. A regional organization such as the Council is likely to find itself increasingly responding to environmental policies determined at the national or international level, instead of making environmental policy decisions itself. This draft plan focuses most of its environmental analysis on an issue that fits this description: global climate change.

Global Climate Change

The possibility that global climate change is occurring, driven by emissions of "greenhouse" gases[20] and other human activity, has

[19] Economists define externality as a byproduct of an economic activity that is not borne by the parties involved in that activity. Environmental externalities are the environmental effects that we impose on others, which are not included in the direct cost of our actions to us.

[20] Greenhouse gases include carbon dioxide (CO_2), which is the most important,and methane (CH_4), nitrous oxide (N_2O), low-altitude ozone (O_3) and chloroflourocarbons (CFCs).

received increasing attention in recent years. The potential effects of such climate change include higher temperatures, changes in precipitation patterns, changes in ocean currents, inundation of coastal land as the mean sea level rises, and increased intensity and frequency of storms. The potential for damage from these effects has led to intense scientific research and international discussions to understand what sort of response might be appropriate.

> **The region faces the risk that greenhouse gas emissions will have to be controlled and/or offset in the future.**

Measures to mitigate damage from climate change could include reductions in greenhouse gas emissions by using different fuels for energy production, reducing transportation fuel use, increased efficiency of energy use, removal of greenhouse gases from the atmosphere and direct responses to damage, such as building higher seawalls.

While the Council focuses primarily on the issue of possible global climate change in this draft plan, this focus is not because other environmental effects are not significant. This focus was chosen because:

Control efforts of other emissions have already made a difference: Many effects, such as emissions of sulfur dioxides of nitrogen (NO_X) and particulates, are already controlled to levels such that taking them into account does not change the preferred portfolio of new resources. In addition, market mechanisms, such as tradable emission rights or offset requirements, account for some of these effects (SO_2 and in some areas NO_X) as operating costs of existing resources. To the extent that resource operators are expected to cover the cost of their emissions with amounts that approximate the damage resulting from emissions, they will make operating decisions that take proper account of the environmental damage.

Many effects are project-specific: Many environmental effects are specific to unique qualities of resource design and location that can only be evaluated when specific projects are evaluated. The Council, in a long-term, regionwide plan, can generally describe these effects, but it cannot quantify impacts of actual projects. This evaluation is most appropriately done when specific projects are proposed. The Council recognized this in the 1991 Power Plan and committed to work with the state and local bodies responsible for establishing siting criteria that take into account localized environmental effects.

The Council's fish and wildlife program also addresses impacts of the power system: The hydroelectric system has had very significant impacts on fish and wildlife, particularly anadromous fish. The Council was given special direction to deal with these environmental effects through its Columbia River Basin Fish and Wildlife Program. The Council's power planning analysis takes into account the effects on the power system of fish and wildlife recovery efforts, but leaves the determination of what these recovery efforts should be to the fish and wildlife program process.

Global climate change could significantly change the power system: The steps that might be taken to mitigate climate change have the potential to change significantly the region's choice of energy resources. The potential damage from climate change ranges from disruption of agriculture, natural vegetation and wildlife from changed temperatures and rainfall patterns, to inundation of islands and coastlines because of higher sea level, to damage from more-intense storms. Estimates of possible damage costs from global climate change cover a wide range, but values at the upper end of the range would justify changing our generation and use of electricity, as well as other uses of energy (e.g., transportation).

Special Difficulties of the Climate Change Issue

The issue of global climate change has features that make it even more difficult to deal with than other environmental issues. First, while scientific consensus appears to be emerging that human

> **Global climate change has features that make it even more difficult to deal with than other environmental issues.**

activity is affecting the global climate,[21] there is still great uncertainty regarding the degree of climate change we face, its costs and the effects of efforts to mitigate such change. Scientists disagree about the mechanisms at work and the damage that may result.

Second, the *global* nature of the problem means climate change is an "externality" to our region, as well as to the individuals in the region. Whatever damage is caused by our region's greenhouse gas emissions is distributed globally; that is, it is experienced by people and ecosystems throughout the world. Likewise, any damage that our region suffers from global climate change is determined by greenhouse gas emissions throughout the world. This means that even if scientific uncertainty were eliminated, the region could not secure a stable climate by its own decisions and efforts. As is typical in situations with externalities, there would be inadequate incentive for each individual and each region to take actions that were in the global interest.

Because global climate change is an externality to each individual country, a response to climate change (if scientific consensus develops to justify a response) would be most effective if it were a cooperative international effort, with mutual commitments from most of the world's nations. Preliminary diplomatic negotiations are under way to make such cooperation possible if it turns out to be necessary.

Managing Risk to the Power System

Given the uncertainties surrounding the climate change issue, the inability of the region to control its climate by its own action and the difficulties implied by the ongoing transition to competitive electricity markets, the Council has approached the issue as a problem in managing risk to the power system. The region faces the risk that greenhouse gas emissions will have to be controlled and/or offset in the future. Such control would likely require policies such as a carbon tax or emission caps with tradable allowances. The risk to the region, then, is that fossil fuel burning may become more costly in a discrete step sometime in the future.

The size of this risk is determined by the magnitude and timing of this increase in cost, the probability that it will occur, and the cost of adjusting to the increase should it occur. The region cannot reduce the probability that global climate change will require future actions to control it — scientists will eventually come to a consensus, one way or another. The region may, however, be able to reduce the cost and disruption of a carbon tax, if global climate change turns out to warrant one.[22]

Measures to accomplish this reduction fall into two categories. First are measures that affect the production and use of electricity in the region, such as investments in increased efficiency or changes in generating fuel. The Council has reasonably good information about the first category. The cost of increased efficiency and the relative costs of generation by fossil, renewable and nuclear fuels in our region have been the subjects of Council analysis for every power plan.

Second are measures to offset emissions in this region by actions elsewhere; for example, investment in efficiency or fuel switching in the power system of a developing country, or the absorption of carbon by forestry practices in the United States or overseas. Measures in this "offset" category show promise of being some of the cheapest ways to respond to a need to control greenhouse gas emissions. These measures, unfortunately, are not nearly so well-studied as those in the first category.

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[21] See the "IPCC Second Assessment Synthese of Scientific-Technical Information Relevant to Interpreting Article 2 of the UN Framework Convention on Climate Change 1995." (http://www.unep.ch/ipcc/syntrep.html on the Worldwide Web)

[22] Though control policies could take several forms, we use a carbon tax as a representative example. Other policies, such as tradable emissions under a cap, will have roughly equivalent effects on utilities' incentives at the margin.

In preparation for this plan, the Council commissioned an analysis of measures to offset ›on dioxide emissions.[23] While the offset ‹ential appears promising, the quality of the data does not allow the development of a "supply curve" of offsets with much confidence. For example, incentives to invest in offsets to emissions depend on legal and institutional steps, such as the definition of new kinds of property rights. Such rights might be obtained by party A for reforestation work and sold to party B to satisfy party B's carbon tax obligations. The definition of these new property rights will need to deal with conceptual problems, such as assurance that a reforestation project is truly an increase in sequestered carbon, not merely a relocation of timber-cutting activity. Many of the measures that offer promise of inexpensive control of climate change (e.g., carbon sequestration in forests) are not completely inventoried. The size and cost of this inventory will depend in part on the definition of offset rights.

Analytical Approach

'he past, the Council has been able to estimate costs and benefits of reducing other kinds of ›sk using its computer model, ISAAC (Integrated System Analysis of Acquisitions).[24] ISAAC would be the preferred tool for analyzing strategies to deal with the risk of a carbon tax as well. Unfortunately, the quality of available data means that we could have little confidence in the results.

The fundamental information necessary for an analysis using ISAAC is some sort of probability distribution of the outcomes (e.g., the level and timing of a carbon tax) that present risk to the region, and estimates of costs of the measures being considered to respond to the risk. While our understanding of global climate is improving, it does not yet support the estimation of a credible distribution of global climate change outcomes. The estimation of the cost of strategies to control emissions of greenhouse gases also faces serious difficulties.

Because of these problems, this draft plan does not treat the risk of global climate change with the kind of quantitative analysis applied to other issues. Instead, it provides illustrations of how much potential impact a control policy for greenhouse gases might have on:

- The cost of the power system;
- The value of conservation that is cost-effective on the basis of energy savings alone, but at some risk of not being acquired; and,
- The net cost of maintaining some acquisition of renewables.
- For purposes of illustration, carbon tax levels of $10, $25 and $40 (in January 1995 dollars) per ton of carbon dioxide were used. These values are illustrative of the range of values commonly cited.[25]

Power System Cost Analysis

To illustrate the potential impact of a carbon tax on the overall cost of the region's power system, the Council estimates that supplying the region's electricity in 1996 will result in the emission of 11.6 million tons of carbon dioxide. If a tax of $10-per ton of carbon dioxide were in force and no changes were made to the operation of the power system, the region's total carbon tax payment would be $116 million, a 1.7 percent increase in the total regional bill for electricity. Under the same assumptions, a $40-per ton tax would cost four times as much.

The region appears likely to rely increasingly on fossil-fueled generation in the future, making it potentially more vulnerable to a carbon tax. If current acquisition patterns hold, the Council's forecasts project an expected level of carbon dioxide emissions of 27.3 million tons in 2005. If a tax of $10 per ton of carbon dioxide were imposed in that year, in the absence of adjustments to the operation of the power system, the tax payment would be $273 million, or a 3.7 percent increase in the expected regional electricity bill. A tax of $40 per ton would impose a proportionately larger tax bill and a proportionately larger increase in the total electricity bill, $1.1 billion and 14.7 percent, respectively.

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[23] ...xler and Associates, Inc., "Considerations in the Construction ... CO_2 Mitigation Cost Curve for the Next Northwest Power Plan," August 1995.

[24] See Appendix H for a further description of ISAAC.

[25] See Table 1 of "Accounting for Environmental Externalities in the Power Plan," Northwest Power Planning Council Issue Paper 94-50, October 1994.

BEFORE THE
ENERGY FACILITY SITING COUNCIL
OF THE STATE OF OREGON

In the Matter of the Application for a Site Certificate of Portland General Electric Company for the Coyote Springs Cogeneration Project

DIRECT TESTIMONY OF JIM LAZAR

Contents

Exhibits

____(JL-2) PGE's "Authorization for Project" Study (Confidential)

Q. What are your name, address, and occupation?

A. Jim Lazar, 1063 Capitol Way S. #202, Olympia, Washington 98501. I am a consulting economist specializing in utility rate and resource studies.

Q. Please summarize your educational background and experience.

A. Following undergraduate and graduate study in economics at Western Washington University, I served on the staff of the Washington State Senate from 1977-79. I have been engaged in utility rate consulting since 1979. My clients include utilities, regulatory bodies, state consumer advocates, and public interest groups. I currently have consulting activities underway with the Office of the Attorney General, State of Washington, with Mason County Public Utility District #3, Snohomish County Public Utility District, and the Washington Utilities and Transportation Commission. I have appeared before state regulatory commissions in Idaho, Illinois, Montana, Oregon, California, Hawaii, and Arizona, and before numerous other local and federal regulatory bodies. I served as the lead author of a book on electric utility cost allocation and ratemaking policies published in 1982. I am a member of the faculty of Edmonds Community College, where I teach Energy Economics. I have appeared previously before this Commission in the Hermiston Generating Project application.

Q. What is the purpose of your testimony in this proceeding?

A. I have been requested by the intervenors to address the following issues:

1) Has PGE foregone more economical and less environmentally harmful generating alternatives, through use of an unjustified and subjective

preference for utility-owned resources and by an unjustified financial penalty applied to non-utility generators?

2) Has PGE failed to pursue economical and environmentally benign resource options which were identified to it during the development of its 1992 Least Cost Plan?

1 PGE HAS FOREGONE OPTIONS MORE ECONOMICAL THAN THE PROPOSED COYOTE SPRINGS PROJECT.

Q. Has PGE foregone resources that are more economical and less environmentally harmful than the proposed Coyote Springs project?

A. Yes.

Q. What is the basis for this conclusion?

A. My response to this question is based in part upon PGE's Response to Data Request #32, which is appended as an exhibit to this testimony, Exhibit ___(JL-2). PGE has stamped "confidential" on every page of this response. Consequently, under the terms of the protective order entered by the Hearing Officer in this case, my response must also be "confidential." Those who have not signed the protective order in this case will receive a copy of this testimony with all portions based upon the PGE response blacked out. I understand that the intervenors will move for the confidentiality to be removed from the PGE PGE's Response to Data Request #32. If it is so removed, then the intervenors can distribute the full testimony to all interested persons.

The Company's "Authorization for Project" study submitted to its Board of Directors in 1993 lists several projects which PGE calculated to be lower cost *than the Coyote Springs project. The Company-owned projects which were lower in cost that Coyote Springs include the 110 mw Boise Cascade cogeneration project, the 675 mw Beaver gas-fired project, the 750 mw Beaver gas-fired project, the 230 mw Boardman gas-fired project, and the 220 mw Trojan gas-fired project. In addition, the study identified independently developed projects by U.S. Generating Co. and Smurfit Corporation which were lower in cost, and by WillPen, L.S. Power, and Zurn Industries which were considered higher in cost than Coyote Springs.*

Q. What were the estimated levelized costs of each of these resources as calculated by the Company?

A. The costs shown below should be compared with the estimated cost for power from the Coyote Springs project as shown in Exhibit ___(JL-2). The cost of U.S. Generating Co.'s Hermiston Generating Project (HGP) presented in the first line of the table is taken from my testimony before EFSC in the siting proceeding for that plant. The other costs are taken from Exhibit ___(JL-2).

note to dan: table appeared to have right column too narrow to me.

COST OF PROPOSED GENERATING PROJECTS (Levelized 1992 Dollars) PROJECT	**MILLS/KW H**
U.S. Generating Co. Hermiston Generating Project	27.4
Boise Cascade	*27.7*
Beaver (675 mw)	*30.3*
Trojan CCCT (220 mw)	*30.8*
Beaver (750 mw)	*31.5*
Boardman	*32.8*

U.S. Generating	*32.9*
Smurfit	*33.0*
Coyote Springs	***33.6***
WillPen	*34.0*
Zurn	*34.3*
L.S. Power	*36.3*

As is evident, PGE states that the Coyote Springs project is the *most expensive* of the Company-owned resource alternatives and is also *more expensive* than several of the non-Company owned options.

Q.Do you have other evidence to support your statement that the power from the Coyote Springs project will be more expensive than other available alternatives?

A.Yes. In my testimony to EFSC on the Hermiston Generating Project, I found that the life-cycle levelized cost of the power would be approximately 27 mills/kwh (Expressed in levelized 1992 dollars), or about 20% less than the life-cycle levelized cost of power from the Coyote Springs project. In addition, the terms of the Hermiston Project power sales contract allow Pacificorp to discontinue purchase of power from the project after 20 years; if gas prices soar or power demand drops, this could be an extremely valuable contract feature. Conversely, as a Company-owned facility, PGE would have no way to avoid the and remaining undepreciated plant investment and other fixed costs, if the Coyote Springs project became uneconomic.

Q.Does PGE agree that the Hermiston Generating Project would have lower costs than Coyote Springs?

A.No. *In its AFP study, PGE asserts that U.S. Generating Co.'s estimate of Hermiston project cost is based on a lower O&M cost assumption that it assumes for Coyote Springs. PGE further asserts that, since the two projects are technically similar, the O&M costs should be comparable.* PGE ignores the fact that the Hermiston Generating

Project O&M costs are contractually determined, and the cost to PP&L will be as set forth in the contract, <u>regardless</u> of the actual costs to U.S. Generating Co. PGE's O&M costs, conversely, will normally be allowed into rates, unless they are found to be imprudent.

2PGE ERRONEOUSLY PENALIZES NON-UTILITY RESOURCES IN DETERMINING RELATIVE COST.

Q.Is PGE correct that a cost premium should be added to the cost of non-Company owned generating projects?

A.No. In its 1992 Least Cost Plan (Section 8-6), PGE applies a penalty of $33/kw/year to purchased power contracts (38% of the fixed cost) for alleged "increased financial risk." PGE goes through an example to purportedly show the impact which could occur under one theory. It fails entirely to show what happens if a contingency occurs -- i.e., that a generation resource fails to perform. Referring to the table on page 8-6.3 of PGE's 1992 Least-Cost Plan, PGE's example shows what happens only if a project is operational. If a non-utility project fails, the utility payment obligation ordinarily ends (under the terms of the power sales contract), and the utility would return to 50% debt and 50% equity. Conversely, if the utility-owned resource were to fail, and the utility had to write off a $200 million investment from its post-investment capital structure of $1600 debt and $1600 equity, it would have $1600 in debt and $1400 in equity, and only a 46.7% equity capitalization ratio. Thus, the "own" scenario is much more financially risky to the Company than the "purchase" scenario.

The only way the utility would likely face a writeoff associated with a purchased power resource would be if the acquisition were found to be imprudent by the regulator. Such determinations, with respect to operating expenses paid for resources actually received, are typically made based upon the information available at the time the decision to purchase the resource is made, not retrospectively based upon changed circumstances. Assuming that PGE is careful at the outset to select cost-effective resources, there should be virtually no regulatory risk associated with purchased power, while there remains a great financial risk associated with Company-owned resources such as Coyote Springs.

In sixteen years of regulatory consulting, I have witnessed numerous utilities receive significant write-offs associated with failed Company-owned resources or Company-owned resources which cost more than available alternatives. I am only aware of two proceedings in which the recovery of operating expenses associated with purchased power has been seriously challenged (WUTC Docket No. UE-921262, ongoing; OPUC Docket No. UE 54, disallowance of cogeneration costs rendered moot when regulated utility sold system to unregulated cooperative). I am unaware of any proceedings where Commissions have actually removed the cost of purchased resources from rates where the purchases were found to have been prudent.

PGE asserts a "debt leverage" premium is appropriate to "reflect the increased financial risk associated with purchase contracts." This approach, which is being asserted by other utilities and vigorously contested by non-utility generators, is based on the premise that a utility incurs a fixed cost obligation under a purchased power contract, but has no equity return associated with the project. Thus, to assure bondholders that their investment in the Company's other facilities are secure, utilities suggest that they need to increase their equity capitalization ratios, which drives up rates.

Q.Do you agree with PGE's position?

A.No, and for a variety of reasons. First and foremost, there are very significant benefits to ratepayers associated with non-utility owned generation. This is <u>extremely</u>

obvious in the case of PGE. Where a utility owns generating resources, it continues to incur fixed costs even when the projects are inoperable. A current PGE rate proceeding before the Oregon Public Utility Commission (OPUC) is centered on the recovery of investment costs and expenses associated with the terminated Trojan nuclear project. While the OPUC (or the Oregon courts) may reject continued inclusion of Trojan costs in rates, nonetheless there is a risk to ratepayers that they will be required to continue to pay PGE for depreciation, ratebase return, and operating costs (including decommissioning costs) because Trojan is a company-owned project.

If Trojan were a non-utility resource, PGE would not have to continue to pay the developer, if the project were to cease delivering energy. Nor would PGE have to pay off the developer's undepreciated capital investment in the project or pay the developer a profit on that investment or pay for the project's decomissioning or dismantling or other disposal. In fact, a non-utility developer typically must pay substantial compensation or penalties to the utility, if the project ceases operation prior to the end of the contract term. For example, the power sales contract proferred to PGE by Pioneer Energy Partners (PEP) on August 13, 1993, for the output of a 228 mw gas-fired cogeneration project at the Smurfit Newsprint Corporation plant in Newberg, Oregon, includes "completion security" equal to $10 million (rising to as high as $30 million, if the project completion date is delayed). The proferred contract requires PEP to pay this amount to PGE, should the project be terminated prior to commercial operation. The contract also requires PEP to grant to PGE a subordinated morgage on the project and to post "operating security" of $30 million to be used to pay PGE's damages, should PEP default on its obligation to provide power. And this was the contract PEP proferred to PGE. The final terms of an actual contract may require even more "security" for the utility.

Second, utilities throughout the region have demonstrated that they are able to borrow up to 100% of their financial needs in spite of 100% dependence upon purchased power. The recent creation of Emerald PUD, Columbia River PUD, and the Oregon Trail Electric Cooperative are examples of utilities which were able to finance purchase of their entire systems at a time when they owned <u>none</u> of their own generation, and they were able to finance on reasonable terms.

Finally, PGE acknowledges that it may have difficulty financing the Coyote Springs project, and that, if it makes expenditures but is unable to complete and operate the project (as occurred with the Pebble Springs, Skagit, and WPPSS 3 nuclear projects), the Company's financial health may be impaired, placing at risk its ability to provide economical and reliable service to its Oregon consumers. In the ANP, PGE states:

Inadequate regulatory support for the continued recovery of Trojan costs in rates would place additional pressure on the Company's balance sheet, impair our access to the capital makrets, subsequently raising our cost of capital.

In light of the uncertainty of "adequate regulatory support," it appears that PGE cannot say with any confidence that the financial assumptions it has made with respect to Coyote Springs will be achieved. The assumed cost of debt and equity, therefore, may be "best case" assumptions, rather than the result of objective analysis. In fact, the Company's ability to successfully complete the project and provide reliable service to consumers is uncertain, because of the risk posed to shareholders by Company-owned resources, a risk which PGE has not considered as an offset to its alleged "debt imputation" to independently developed resources.

Q.Have you been involved in analyzing the issue of whether independent power production poses risks or benefits to consumers of electric utilities and whether the "debt imputation" theory is valid?

A.Yes, on several occasions. I served as a consultant to the California Energy Commission in 1982 in Docket OII-2, and prepared a report for the CEC entitled <u>"A</u>

Ratepayer's Perspective on Avoided Cost Pricing under PURPA." That report concluded that there are benefits to consumers of moving generation "off" of the utility's balance sheet in the form of greater certainty of actually receiving power for amounts paid, and reducing utility's construction requirements and therefore their cost of capital.

In 1992, I was retained by the State of Hawaii Department of Commerce and Consumer Affairs to examine appropriate regulatory treatment of purchased power in a proceeding before the Hawaii Public Utilities Commission Docket No. 7310. In that examination, I concluded that benefits to ratepayers associated with contractual resources far exceed any risk associated with "debt imputation."

Finally, in 1992, I was retained by the Office of the Attorney General in Washington State as part of a proceeding before the Washington Utilities and Transportation Commission in Docket No. UE-930537 to examine whether purchased power imposes risks on the capital structure of electric utilities. In that examination, we found that the "non-cost" benefits of non-utility generation generally exceeded any "non-cost" risks, such as debt imputation.

On the basis of these three consulting projects, I believe that purchased power is more valuable to a utility than company-owned resources, and a utility's resource acquisition priorities should reflect this.

Q.What is the basis of PGE's stated preference for utility-owned resources over purchased resources?

A.PGE's "AFP" report contains 3 pages on this issue (34-36). All of the discussion deals with "shareholder value." Not a single word addresses whether this preference provides any benefits to consumers, to the state of Oregon, to the environment, or to *third parties. Based solely on shareholder value issues, PGE adopts in it's "Strategic Plan" a commitment that 60% of all new supply resources will be Company owned.*

Q.Is this policy rational?

A.No. PGE has not defended any policy to prefer Company-owned resources in either its 1992 Least Cost Plan or in any docket before this body or the OPUC. It is irrational to apply an artificial penalty to purchased resources or an artificial preference for Company-owned resources.

What is worse, PGE does <u>both.</u> *It first applies a "leverage penalty" of 1-3 mills/kwh to purchased resources, as shown in the ARP at page 11.* Then, it separately adopts a "strategic policy" to have a certain percentage of its new supply side acquisitions be Company-owned resources. No credit is given for the fact that purchased resources <u>reduce</u> the risk borne by ratepayers.

3PGE HAS FAILED TO ADEQUATELY CONSIDER READILY AVAILABLE GENERATION ALTERNATIVES.

Q.What is the Weyerhaeuser cogeneration project?

A.The Weyerhaeuser project is a 390 mw cogeneration project generally similar in design to the proposed Coyote Springs project, located at Longview, Washington, across the Columbia River and a few miles downstream from the Trojan site. It was designed with the same GE Frame 7 turbines used in the Coyote Springs Project design, but the electrical output is smaller because a much larger proportion of the output will be used as steam in the pulp and paper mill to which it is connected, unlike the Coyote Springs Project which has no confirmed steam host and no nearby steam customers anywhere near the size of the Weyerhaeuser paper mill.

Q.Why is the Weyerhaeuser project a legitimate alternative to the Coyote Springs project?

A.The Weyerhaeuser project is much further along in the development state than Coyote Springs, and has the following advantages over Coyote Springs:

1 It has already received a site certification, signed by Governor Lowry in early 1994.

2 It has a readily identifiable steam host, the Weyerhaeuser Longview facility, which is Weyerhaeuser's largest pulp and paper mill. The project is much better thermally matched than the Coyte Springs Project, with design steam production of 1,500,000 pounds per hour, which is approximately 3 times the design capability and 10 times the expected steam production of Coyote Springs. It will displace six existing boilers.

3 It is located adjacent to the PGE service territory, reducing transmission costs and losses.

4 The site is already connected to both the natural gas pipeline system and the electrical transmission system; design work on expansion of the existing gas pipeline connection is complete.

5 The project is located on the transmission grid in an area (near Trojan) where PGE and BPA have argued that substantial generating is needed to ensure the stability of the regional transmission grid against "voltage collapse."

6 Because the Weyerhaeuser cogeneration project will displace the use of on-site boilers which operate at times with residual fuel oil, the Weyerhaeuser project is expected to reduce emissions of oxides of nitrogen, sulphur dioxide, Non-Methane Hydrocarbon, and particulates in the Western Washington / Western Oregon airshed, as well as reductions in solid waste production and wastewater generation; the CO2 emissions of the Weyerhaeuser

and Coyote Springs projects would be similar.

Q. What is the status of the Weyerhaeuser project?

A. In terms of permits, it is essentially ready for construction. Weyerhaeuser has secured expansion capacity on Northwest Pipeline to bring fuel to the project. Oil storage facilities are already in place, due to the large steam load of the existing facility, but with firm pipeline capacity would seldom be used. To date, however, Weyerhaeuser has not identified a purchaser for the output from the project, and it is my understanding that they have delayed the start of construction pending resolution of this issue.

Q. What reason has PGE given for its failure to consider this alternative?

A. PGE has refused to even discuss the project. In our data requests #30 and #31, we asked the Company for analysis and correspondence relating to the Weyerhaeuser project. They have, so far, refused to supply any documentation. If and when the documents are provided, supplemental testimony may be submitted.

Q. What is the Smurfit (or Pioneer Energy Partners) cogeneration project?

A. The Smurfit project is a 220 mw cogeneration facility at a pulp and paper mill inside the PGE service territory. Pioneer Energy Partners proposed to sell the output of this project to PGE at a rate 13% below PGE's filed avoided costs. The terms of the proposed agreement were essentially as I described general terms for independently-developed resources, with payment to the developer contingent upon performance of the resource.

DIRECT TESTIMONY OF KEVIN BELL

Q. Please state your name, address, occupation and qualifications.

A. Kevin Bell, Convergence Research, 6001 Phinney Avenue North, Suite 2, Seattle, Washington, 98103. I am a consultant specializing in energy and water resource planning and public policy issues.

I have been working in the public sector, public interest sector, and as a private consultant on these issues for over twelve years. My clients include utilities, public agencies, and public interest groups. Exhibit ___ (KB-2) details my professional experience.

Q. What is the purpose of your testimony?

A. I have been asked to provide a comparative analysis of the emission values recommended by the Oregon Department of Energy (ODOE) as part of its mandate to implement Oregon SB 576 (1989), which requires the State of Oregon to develop a strategy for reducing the emission of greenhouse gasses to 20% below 1988 levels by the year 2005. I should note that in the case of greenhouse gas emissions related to power production, the technical appendix developed by ODOE as part of their recommendation estimates a net increase of 160% in net regional greenhouse gas emissions related to electric power production, requiring a 69% reduction or offset in expected power production emissions in the year 2005 in order to meet state emission goals.

In addition, I discuss some of the implications of the environmental costs and fuel price risks associated with emissions from the proposed Coyote Springs Project (CSP). Mr. Lazar is commenting on the risk and implied debt implications of purchased supply side or demand side projects versus company owned generation, as well as the question of who should bear the risk of price shocks in the case of resources with significant price risk components, such as CSP. Both Mr. Lazar and I will be discussing resources which should be considered by Portland General Electric (PGE) as alternatives to the Coyote Springs proposal.

Q. Do you believe the range of environmental emission values recommended by ODOE and the Oregon Public Utility Commission (OPUC) are reasonable?

A. Yes. The ODOE analysis began with a stated policy goal of reducing statewide greenhouse gas emissions to 80% of 1988 levels by the year 2005. The analysis recognizes that even this goal merely slows, rather than reverses, global warming and ozone depletion trends:

"It is an ambitious goal in terms of the changes it would require. On the other hand, acheiving the 20% reduction goal worldwide would only slow the accumulation of greenhouse gasses." ODOE (1990), page 7

The high end of the range of emission values implemented by the OPUC in proceeding UM 424 reflects the results of the ODOE study, which outlined a range of options costing up to \$40/ton of CO_2 equivalent for reducing global warming emissions.

In addition to examining the ODOE study, I examined 36 other valuations of emission costs. The results of this study are presented as Exhibit ___ (KB-3). As the summary chart in Exhibit ___ (KB-4) demonstrates, the range of environmental values adopted by the OPUC range from well below to slightly above the median of a broad range of estimates of emission values.

Q. What do the OPUC emission values imply in terms of the proposed generating project?

A. They show that absent enforceable and verifiable efforts by either the project developer or the purchasing utility to assure full net mitigation of emissions, a full cost determination of the Coyote Springs project should add between 5 and 19 mills per kWh (1990\$) in emission costs.

As Mr.Lazar points out in Exhibit ___(JL-2), there is a significant possibility that these costs will become directly expressed as a carbon tax sometime during the expected life of this project. Aside from the Oregon state mandate to reduce greenhouse gas emissions significantly, utility customers face a significant financial risk exposure unless approval of this project is made contingent on full mitigation of emissions, development of all efficiency and renewable resources costing less than the full cost of CSP or, at a minimum, an enforceable guarantee by the utility shareholders to accept the full financial risk of any future emission valuations.

Q. Are there other risk factors associated with this project?

A. Yes. As PGE mentions in their Supply Side Resource Strategy AFP document dated March 23, 1993, gas supply costs are approximately two-thirds of the expected total project cost. PGE proposes to mitigate this risk by using multiple suppliers and multiple variable length contracts to mitigate the risk exposure associated with any individual source of supply.

Q. Doesn't that mitigate risks associated with fuel prices?

A. No, it does not. It is a sensible approach to reducing the reliability and price risk exposure associated with reliance on individual suppliers. However, it is insufficient for dealing with systemic price fluctuations in regional gas markets.

Regionally, plans are underway for construction of over 9,000 MWa of gas combustion turbine and cogeneration projects. Although only a fraction of these projects are likely to be completed, the incremental competitive price impact on gas supply and transportation markets could be significant. There is no evidence that PGE has seriously considered this impact in its calculations.

More generally, the trend in regional gas supply markets is towards short-term contracts, or long-term contracts indexed to market conditions, rather than a fixed escalation schedule. PGE appears to have received a number of attractive preliminary short and medium term contract offers from suppliers, but has provided no evidence that they can produce a portfolio of enforceable, low cost, firm price, or even firm index contracts for as long as half of the expected project life.

PGE's 1993 Supply Side Resource Strategy AFP indicates an expected gas commodity price of approximately $2.00/MMBTU in 1996. 1993 monthly regional spot market prices on Northwest Pipeline averaged around $1.85/MMBTU, approximately a 30% increase over 1992 spot prices. The potential impact of continued pressure on gas commodity prices on the cost-effectiveness of the Coyote Springs proposal does not appear to have been seriously considered by PGE.

Recent work on valuation of resource options which reduce exposure to major price fluctuations, or which delay or reduce the commitment to large resources with significant unknown cost components indicates that gas commodity price uncertainty should be considered a significant factor in making a present value determination of the cost-effectiveness of a major new resource. There is no evidence that PGE has considered this factor in its decision to proceed with Coyote Springs.

Q. PGE is in the unique position of needing to rapidly replace the output of a large, prematurely terminated generating project. Are reasonable alternatives to the proposed Coyote Springs project or an equivalent project available as replacements for Trojan?

A. Yes. PGE has declined to provide any detailed information about the bids received under its "unsolicited bid" process for Trojan replacement resources, but we can readily identify some reasonable near-term alternatives. Weyerhauser is prepared to construct a 290 MWa cogeneration project near Longview, Washington. Project energy and capacity is available at a cost roughly comparable to that of Coyote Springs. PGE has declined to provide any evidence that purchase of the output of this project has been seriously considered. The Supply Side Resource Strategy AFP identifies a thermally matched 100 MWa cogeneration proposal at the Smurfit plant within its service territory, offering higher end-use efficiencies at a cost approximately equal to that of Coyote Springs. PGE has since rejected development of this project. Assuming these projects utilize gas energy more efficiently than the proposed Coyote Springs project, exposure to gas supply cost fluctuations are reduced even if PGE is fully at risk for the operations and fuel cost components of these projects. If contract terms impose operations reliability and fuel price risks on the developer, these projects should be even more attractive to PGE.

More generally, PGE has not convincingly demonstrated that its current practice of replacing power from Trojan with a portfolio of bulk energy and capacity purchases is not a viable medium-term to long-term option. Presumably, PGE's experience with utility system management, combined with its existing resources and the added flexibility associated with a major commitment to demand side resources, should allow it to compete effectively in a deregulated wholesale market environment against competing buyers who lack the market leverage and system flexibility enjoyed by PGE. Unlike gas contracts, long term, fixed index electric supply contracts appear to be available from utilities and independent power producers, potentially allowing PGE to use a market resource portfolio to mitigate the risks associated with reliance on a single large energy production source. PGE would then be able to combine the options of:

- deferring dependence on Coyote Springs or a similarly sized gas project,
- waiting to determine whether the current turmoil in regional electric energy markets will result in the exit of direct service industrial customers from the region, freeing up significant portions of the low-cost Federal Columbia River Power System,
- reducing or eliminating long term reliance on natural gas by purchasing a portfolio of purchased system capacity, renewable and DSM transfer resources, or
- using purchase contracts as a carryover to allow PGE to develop a utility-owned portfolio consisting of an accelerated commitment to regional priority resources, inclúding demand side, renewable, gas direct application and thermally matched cogeneration projects as part of a transition from a generating utility to an aggressive, market-oriented energy services company.

Again, there is no evidence that PGE has seriously considered these options as alternatives to the Coyote Springs project, or as alternatives to PGE's more general intent to replace the single shaft risk of the Trojan project with the single fuel risk of natural gas.

Q. What are your conclusions from this analysis?

A. I have three conclusions.

First, Oregon has mandated an effort to reduce greenhouse gas emissions significantly. The range of values applied by the OPUC to emissions appear reasonable.

Second, these valuations imply a significant environmental cost and potential financial risk, which should be explicitly considered as part of these proceedings. Unless emissions are mitigated, or unless the burden of associated risks is firmly placed on PGE shareholders, approval of this project as proposed would not only violate Oregon state policy, but would expose utility customers to additional financial risks as well.

Third, PGE does not appear to have adequately considered fuel price risks associated with the project, and does not appear to have adequately considered environmentally and economically comparable or superior resource options in its decision to proceed with the Coyote Springs proposal.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UE-991409
Exhibit 509

Response of Public Counsel Witness Jim Lazar
To Data Request of Puget Sound Energy

13) With regard to the testimony of Jim Lazar at pages 6-7, lines 21-25, 1-21, identify any and all potential material expenses that are not included in your analysis of future costs of the Centralia facilities.

Response:

All "potential material expenses" included in the Centralia cost estimates from Pacificorp, Puget, and Avista are contained in the respective scenarios prepared by Mr. Lazar. Mr. Lazar did not do an independent assessment of the "potential material expenses" for Centralia.

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 509
ADMIT ☑ W/D ☐ REJECT ☐

Docket No. UE-991409
Exhibit 510

Response of Public Counsel Witness Jim Lazar
To Data Request of Puget Sound Energy

14) With regard to the testimony of Jim Lazar at pages 7-8, lines 25-29, 1-5, describe in detail your expertise in evaluating and estimating future costs, including overhaul costs, of coal-fired generation plants.

Response:

Mr. Lazar has general expertise in the economics of electrical generation, as evidenced by publications dating back as far as 1976 (see response to #7). The witness did not apply any independent expertise in estimating overhaul costs of coal-fired generation plants. The witness uses the estimated costs for maintenance of Centralia prepared by the plant operator, Pacificorp, in his base case analysis, and those prepared by the other Applicants in his alternative sensitivity analyses.

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 510
ADMIT ☑ W/D ☐ REJECT ☐

Docket No. UE-991409
Exhibit 511

Response of Public Counsel Witness Jim Lazar
To Data Request of Puget Sound Energy

22) With regard to the testimony of Jim Lazar at page 22, lines 12-15, provide all documents that refer or relate to the likelihood that a carbon incentive mechanism would be included as part of a carbon tax, as described in your testimony.

Response:

The notion of a carbon incentive mechanism, similar to the current tradeable sulphur emissions rights program, was the result of oral communications with Pacificorp and TransAlta. Mr. Lazar has no documents referring or relating to the likelihood of any such program or with the grandfathering, vesting, or phase-in of such a program.

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 511
ADMIT ☑ W/D ☐ REJECT ☐

PSE DATA REQUESTS

25) With regard to the testimony of Jim Lazar generally, provide copies, in paper and electronic format, of all workpapers, including any and all spreadsheet models (including those used as exhibits).

Response:

Mr. Lazar's spreadsheet model contains confidential material which may not be disclosed under the terms of the confidentiality agreement in this docket. The model provided electronically to Jim Elsea has fuel costs and totals including fuel costs deleted from the "Aggressive Cost Containment" scenario, because Pacificorp has not authorized the disclosure of this data, which was obtained from the Confidential response to Staff Data Request #1. If PSE has this data response, Mr. Lazar can assist Puget in reconstructing this sensitivity analysis.

In addition, Mr. Lazar has identified an error in his worksheet (use of wrong NWPPC forecast on pages 1 and 7-12 of Exhibit 501). This is being corrected.

This error appears to lead to Exhibit 501 understating the value of Centralia by approximately $180 million in those scenarios relying on the NWPPC forecast.

In addition, Pacificorp on December 20 filed revisions to its exhibits with respect to the ownership costs of Centralia. Mr. Lazar relied on the Pacificorp exhibits being correct for those scenarios using Pacificorp "Cost of Power" assumptions. Mr. Lazar's will make revisions to incorporate Pacificorp's corrections. These corrections seem to have the effect of increasing the cost of keeping Centralia by about $19 million, which will affect five of Mr. Lazar's scenarios.

None of these changes appears to change in any way Mr. Lazar's basic conclusion that Centralia has value in excess of the offer price, and should be retained.

A copy of the worksheet actually used to produce the exhibits has been provided electronically to Jim Elsea. The corrected worksheet will be provided as soon as the revised exhibits are complete.

Printed workpapers will be provided as soon as the revised exhibits are complete.

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 512
ADMIT ☑ W/D ☐ REJECT ☐

Dockets UE-991255, UE-991262. UE-001409

Workpapers accompanying the Exhibits of Jim Lazar

Page(s)	Workpapers
1 - 7	Scenario 3, PSE Cost of Centralia, Aurora-based Value
	Scenario 7, PSE Cost of Centralia; PSE Value of Centralia as filed
8 - 11	Scenario 4, Pacificorp "Aggressive Cost Containment" Cost of Centralia, NWPPC 11/29/99 Aurora-based Value CONFIDENTIAL due to Pacificorp refusal to waive confidentiality of the fuel costs used in this scenario. Supplied only to WUTC Staff and Pacificorp.
12 - 15	Scenario 5, Pacificorp Cost of Centralia, Pacificorp RAMPP-5 Value
16 - 19	Scenario 6, PSE Cost of Centralia; PSE Colstrip Aurora-based Value
20 - 23	Scenario 8, Avista Cost of Centralia; Avista Value from PC #19 (Revised Value)
24 - 28	Scenario 9, Pacificorp Cost of Centralia; Aurora-based Value; $10/ton carbon tax beginning in 2008
29 - 30	Aurora 11/29/99 forecast results as received from Northwest Power Planning Council staff 12/28/99
31	Workpaper to Exhibit 504, Carrying cost of Centralia 1986 - 98

PSE Cost, PSE Value Revised 12/31/99	Source	2000	2001	2002	2003
Puget Estimate of Cost of Centralia	Puget	24.98	27.41	31.41	30.95
Puget Estimate of Market Price Adjusted	Puget	26.51	26.99	27.46	27.93
Add 1 mill ancillary services value	Puget	27.51	27.99	28.46	28.93
Difference:		2.53	0.57	-2.95	-2.02
Compare to NWPPC Aurora ++		29.63	30.34	31.89	34.76
Difference:		-2.12	-2.36	-3.44	-5.83
Compare to Colstrip Aurora		23.12	24.55	27.00	28.75
Difference:		4.3925	3.435	1.4575	0.18
Output mwh @ 100% of Plant	Puget	8,227,151	8,227,151	8,227,151	8,227,151
Cost of Power ($Millions)		$205.56	$225.53	$258.40	$254.61
Value of Power ($Millions)		$226.35	$230.24	$234.12	$238.01
Sulphur credits included in cost	Puget	$0.00	$0.00	$0.00	$0.00
Net Value of Plant vs. Market:		$20.79	$4.70	($24.28)	($16.60)
Present Value @	0.0716	$19.40	$4.10	($19.73)	($12.59)

Puget Value of Power		24 Years	26 Years
Gain on Sale Required for Breakeven:		$250.89	$277.65
Book Value, Plant:	Avista	$116.51	$116.51
Book Value, Mine:	PP&L	$107.20	$107.20
Total Sale Price Required:		**$474.61**	**$501.36**
Actual Sale Price:	PP&L	$554.00	$554.00
Minimum % Gain On Sale To Ratepayers		**75.96%**	**84.06%**

Puget Cost Aurora Value ++		2000	2001	2002	2003
Cost of Power ($Millions)		205.555141	225.533551	258.402644	254.613599
Value of Power ($Millions)		243.793492	249.620144	262.389972	285.936461
Net Value of Plant vs. Market:		$38.24	$24.09	$3.99	$31.32
Present Value @	0.0716	$35.68	$20.98	$3.24	$23.75

Puget Value of Power		24 Years	26 Years
Gain on Sale Required for Breakeven:		$746.31	$790.49
Book Value, Plant:	Avista	$116.51	$116.51
Book Value, Mine:	PP&L	$107.20	$107.20
Total Sale Price Required:		**$970.02**	**$1,014.21**
Actual Sale Price:	PP&L	$554.00	$554.00
Minimum % Gain On Sale To Ratepayers		**225.96%**	**239.34%**

1

PSE Cost, PSE Value Revised 12/31/99	2004	2005	2006	2007
Puget Estimate of Cost of Centralia	31.75	31.98	32.25	32.89
Puget Estimate of Market Price Adjusted	28.40	30.60	32.56	34.53
Add 1 mill ancillary services value	29.40	31.60	33.56	35.53
Difference:	-2.35	-0.37	1.31	2.64
Compare to NWPPC Aurora ++	37.27	38.34	39.76	41.08
Difference:	-7.87	-6.73	-6.20	-5.55
Compare to Colstrip Aurora	31.14	32.76	34.71	37.06
Difference:	-1.7375	-1.15880525	-1.154399125	-1.531060625
Output mwh @ 100% of Plant	8,227,151	8,227,151	8,227,151	8,227,151
Cost of Power ($Millions)	$261.22	$263.07	$265.31	$270.56
Value of Power ($Millions)	$241.90	$259.99	$276.07	$292.30
Sulphur credits included in cost	$0.00	$0.00	$0.00	$0.00
Net Value of Plant vs. Market:	($19.33)	($3.08)	$10.75	$21.74
Present Value @	($13.68)	($2.03)	$6.63	$12.50

Puget Value of Power

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepay(

Puget Cost Aurora Value ++				
Cost of Power ($Millions)	261.224799	263.06853394	265.31236768	270.56081065
Value of Power ($Millions)	306.60543	315.39107576	327.09033916	337.95980579
Net Value of Plant vs. Market:	$45.38	$52.32	$61.78	$67.40
Present Value @	$32.11	$34.55	$38.07	$38.76

Puget Value of Power

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepay(

2

PSE Cost, PSE Value Revised 12/31/99	2008	2009	2010	2011
Puget Estimate of Cost of Centralia	33.19	33.49	33.78	32.64
Puget Estimate of Market Price Adjusted	35.74	35.42	36.77	37.47
Add 1 mill ancillary services value	36.74	36.42	37.77	38.47
Difference:	3.56	2.93	3.99	5.83
Compare to NWPPC Aurora ++	42.38	42.95	44.03	43.57
Difference:	-5.63	-6.53	-6.25	-5.10
Compare to Colstrip Aurora	38.25	37.95	39.26	39.97
Difference:	-1.505633125	-1.526906	-1.48878475	-1.500369375
Output mwh @ 100% of Plant	8,227,151	8,227,151	8,227,151	8,227,151
Cost of Power ($Millions)	$273.04	$275.53	$277.90	$268.51
Value of Power ($Millions)	$302.30	$299.66	$310.75	$316.50
Sulphur credits included in cost	$0.00	$0.00	$0.00	$0.00
Net Value of Plant vs. Market:	$29.26	$24.13	$32.85	$47.99
Present Value @	$15.71	$12.09	$15.35	$20.93

Puget Value of Power

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepay

Puget Cost Aurora Value ++				
Cost of Power ($Millions)	273.0367349	275.52607467	277.89997931	268.5090299
Value of Power ($Millions)	348.62757249	353.39300449	362.20732141	358.47245154
Net Value of Plant vs. Market:	$75.59	$77.87	$84.31	$89.96
Present Value @	$40.57	$39.00	$39.40	$39.23

Puget Value of Power

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepay

3

PSE Cost, PSE Value Revised 12/31/99	2012	2013	2014	2015
Puget Estimate of Cost of Centralia	33.48	33.92	34.46	34.96
Puget Estimate of Market Price Adjusted	36.27	39.57	39.62	40.96
Add 1 mill ancillary services value	37.27	40.57	40.62	41.96
Difference:	3.80	6.65	6.16	7.00
Compare to NWPPC Aurora ++	45.15	46.69	46.95	48.46
Difference:	-7.87	-6.12	-6.33	-6.50
Compare to Colstrip Aurora	39.16	42.42	42.46	43.79
Difference:	-1.885160875	-1.84991875	-1.83624625	-1.829502625
Output mwh @ 100% of Plant	8,227,151	8,227,151	8,227,151	8,227,151
Cost of Power ($Millions)	$275.44	$279.06	$283.51	$287.61
Value of Power ($Millions)	$306.67	$333.78	$334.22	$345.22
Sulphur credits included in cost	$0.00	$0.00	$0.00	$0.00
Net Value of Plant vs. Market:	$31.22	$54.72	$50.71	$57.60
Present Value @	$12.71	$20.78	$17.97	$19.05

Puget Value of Power

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepay(

Puget Cost
Aurora Value ++

Cost of Power ($Millions)	275.44215963	279.05723662	283.50593817	287.61219918
Value of Power ($Millions)	371.42827579	384.13637261	386.27706873	398.67355367
Net Value of Plant vs. Market:	$95.99	$105.08	$102.77	$111.06
Present Value @	$39.06	$39.91	$36.42	$36.73

Puget Value of Power

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepay(

4

PSE Cost, PSE Value Revised 12/31/99	2016	2017	2018	2019
Puget Estimate of Cost of Centralia	35.50	36.49	44.29	38.34
Puget Estimate of Market Price Adjusted	41.64	43.54	45.76	45.74
Add 1 mill ancillary services value	42.64	44.54	46.76	46.74
Difference:	7.14	8.05	2.47	
Compare to NWPPC Aurora ++	48.48	49.67	50.89	52.13
Difference:	-5.85	-5.13	-4.13	-5.39
Compare to Colstrip Aurora	44.43	46.77	48.93	
Difference:	-1.79306725	-2.23195125	-2.16989225	
Output mwh @ 100% of Plant	8,227,151	8,227,151	8,227,151	8,227,151
Cost of Power ($Millions)	$292.04	$300.21	$364.42	$315.41
Value of Power ($Millions)	$350.78	$366.42	$384.70	$384.55
Sulphur credits included in cost	$0.00	$0.00	$0.00	$0.00
Net Value of Plant vs. Market:	$58.74	$66.21	$20.28	$69.14
Present Value @	$18.13	$19.07	$5.45	$17.34

Puget Value of Power

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepay

Puget Cost Aurora Value ++	2016	2017	2018	2019
Cost of Power ($Millions)	292.04199846	300.21261048	364.41940858	315.41087388
Value of Power ($Millions)	398.87355135	408.63971136	418.65002537	428.91059722
Net Value of Plant vs. Market:	$106.83	$108.43	$54.23	$113.50
Present Value @	$32.97	$31.23	$14.58	$28.47

5

PSE Cost, PSE Value Revised 12/31/99	2020	2021	2022	2023
Puget Estimate of Cost of Centralia	39.30	40.28	41.29	42.32
Puget Estimate of Market Price Adjusted	46.89	48.06	49.26	50.49
Add 1 mill ancillary services value	47.89	49.06	50.26	51.49
Difference:				
Compare to NWPPC Aurora ++	53.41	54.72	56.07	57.44
Difference:	-5.53	-5.66	-5.81	-5.95
Compare to Colstrip Aurora				
Difference:				
Output mwh @ 100% of Plant	8,227,151	8,227,151	8,227,151	8,227,151
Cost of Power ($Millions)	$323.30	$331.38	$339.66	$348.15
Value of Power ($Millions)	$393.96	$403.61	$413.49	$423.62
Sulphur credits included in cost	$0.00	$0.00	$0.00	$0.00
Net Value of Plant vs. Market:	$70.67	$72.23	$73.83	$75.47
Present Value @	$16.54	$15.78	$15.05	$14.35
Puget Value of Power				
Gain on Sale Required for Breakeven:				
Book Value, Plant:				
Book Value, Mine:				
Total Sale Price Required:				
Actual Sale Price:				
Minimum % Gain On Sale To Ratepay				
Puget Cost Aurora Value ++				
Cost of Power ($Millions)	323.29614573	331.37854937	339.66301311	348.15458844
Value of Power ($Millions)	439.42768338	450.20769668	461.25721032	472.5829618
Net Value of Plant vs. Market:	$116.13	$118.83	$121.59	$124.43
Present Value @	$27.18	$25.95	$24.78	$23.67

6

PSE Cost, PSE Value Revised 12/31/99	2024	2025
Puget Estimate of Cost of Centralia	43.38	44.46
Puget Estimate of Market Price Adjusted	51.75	53.05
Add 1 mill ancillary services value	52.75	54.05
Difference:		
Compare to NWPPC Aurora ++	58.85	60.30
Difference:	-6.10	-6.25
Compare to Colstrip Aurora		
Difference:		
Output mwh @ 100% of Plant	8,227,151	8,227,151
Cost of Power ($Millions)	$356.86	$365.78
Value of Power ($Millions)	$434.01	$444.65
Sulphur credits included in cost	$0.00	$0.00
Net Value of Plant vs. Market:	$77.15	$78.87
Present Value @	$14	$13
Puget Value of Power		
Gain on Sale Required for Breakeven:		
Book Value, Plant:		
Book Value, Mine:		
Total Sale Price Required:		
Actual Sale Price:		
Minimum % Gain On Sale To Ratepay(		
Puget Cost Aurora Value ++		
Cost of Power ($Millions)	356.85845	365.77991
Value of Power ($Millions)	484.19186	496.09097
Net Value of Plant vs. Market:	$127.33	$130.31
Present Value @	$22.60	$21.58

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Pages 8 - 11 of the workpapers of Jim Lazar are confidential pursuant to the protective order in Docket UE-991262.

These pages contain material derived from Pacificorp's response to Staff Data Request No. 1, which itself is confidential.

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PPL Cost ; RAMPP5 Value
Revised 12/31/99

	Source	2000	2001	2002	2003	2004	2005	2006	2007
Non-fuel Revenue Requirement	PP&L	$34,328	$44,764	$49,658	$45,177	$47,159	$46,646	$46,435	$46,180
Unit 1 Fuel	PP&L	$33,114	$33,651	$33,973	$34,734	$35,273	$36,059	$38,322	$39,114
Unit 2 Fuel	PP&L	$32,939	$33,604	$34,565	$35,549	$35,143	$36,551	$38,331	$39,010
Total		$100,380	$112,019	$118,196	$115,460	$117,575	$119,257	$123,088	$124,304
PP&L Share of Output	PP&L	3,873,072	3,877,197	3,867,687	3,893,872	3,870,048	3,845,230	3,977,927	3,962,682
Ownership / Operating cost mills/kwh	PP&L	25.92	28.89	30.56	29.65	30.38	31.01	30.94	31.37
Ownership / Operating cost mills/kwh	PP&L	25.92	28.89	30.56	29.65	30.38	31.01	30.94	31.37
PP&L RAMPP 5 Forecast	PP&L	22.9	23.8	24.7	25.9	26.9	27.8	28.9	30.0
Dispatch Benefit proportioned @ 1.71 mills		1.71	1.78	1.84	1.93	2.01	2.08	2.16	2.24
Value with Dispatch Benefit		24.61	25.58	26.54	27.83	28.91	29.88	31.06	32.24
Add 1.00 mills capacity benefit uninflated		25.61	26.58	27.54	28.83	29.91	30.88	32.06	33.24
Output mwh @ 100% of Plant	PP&L	8,153,836	8,162,520	8,142,498	8,197,625	8,147,469	8,095,221	8,374,583	8,342,488
Cost of Power ($Millions)		$211.33	$235.83	$248.83	$243.07	$247.53	$251.07	$259.13	$261.69
Value of Power ($Millions)		$200.67	$208.77	$216.14	$228.17	$235.53	$241.85	$260.10	$268.96
Cost/Value of Sulphur Credits		$9.78	$10.10	$1.99	($6.61)	($6.82)	($7.03)	($6.96)	($6.97)
Net Value of Plant vs. Market:		($20.45)	($37.15)	($34.69)	($8.29)	($5.18)	($2.18)	$7.93	$14.24
Present Value @	0.0716	($19.08)	($32.35)	($28.19)	($6.29)	($3.66)	($1.44)	$4.89	$8.19
Cumulative Present Value:		($19)	($51)	($80)	($86)	($90)	($91)	($86)	($78)

		24 Years	26 Years
Gain on Sale Required for Breakeven:		$282.37	$333.21
Book Value, Plant:	Avista	$116.51	$116.51
Book Value, Mine:	PP&L	$107.20	$107.20
Total Sale Price Required:		**$506.08**	**$556.92**
Actual Sale Price:	PP&L	$554.00	$554.00
Minimum % Gain On Sale To Ratepayers		**85.49%**	**100.89%**

PPL Cost ; RAMPP5 Value Revised 12/31/99	2008	2009	2010	2011	2012	2013	2014	2015
Non-fuel Revenue Requirement	$49,845	$49,860	$49,954	$50,084	$50,289	$50,524	$46,504	$47,201
Unit 1 Fuel	$40,280	$41,380	$42,684	$44,373	$46,681	$47,999	$49,231	$50,587
Unit 2 Fuel	$40,971	$41,805	$43,503	$45,034	$46,545	$47,562	$48,785	$50,115
Total	$131,096	$133,045	$136,140	$139,491	$143,516	$146,085	$144,521	$147,903
PP&L Share of Output	4,016,576	4,026,506	4,077,035	4,131,729	4,204,368	4,216,136	4,216,437	4,216,856
Ownership / Operating cost mills/kwh	32.64	33.04	33.39	33.76	34.13	34.65	34.28	35.07
Ownership / Operating cost mills/kwh	32.64	33.04	33.39	33.76	34.13	34.65	34.28	35.07
PP&L RAMPP 5 Forecast	32.0	33.1	34.2	35.3	36.5	37.6	38.9	40.2
Dispatch Benefit proportioned @ 1.71 m	2.39	2.47	2.55	2.64	2.73	2.81	2.90	3.00
Value with Dispatch Benefit	34.39	35.57	36.75	37.94	39.23	40.41	41.80	43.20
Add 1.00 mills capacity benefit uninflate	35.39	36.57	37.75	38.94	40.23	41.41	42.80	44.20
Output mwh @ 100% of Plant	8,455,950	8,476,854	8,583,231	8,698,377	8,851,300	8,876,077	8,876,710	8,877,591
Cost of Power ($Millions)	$275.99	$280.09	$286.61	$293.67	$302.14	$307.55	$304.25	$311.37
Value of Power ($Millions)	$290.80	$301.54	$315.47	$329.98	$347.20	$358.66	$371.09	$383.53
Cost/Value of Sulphur Credits	($6.94)	($6.94)	($6.91)	($6.94)	($6.91)	($6.90)	($6.90)	($6.90)
Net Value of Plant vs. Market:	$21.75	$28.38	$35.77	$43.26	$51.96	$58.01	$73.73	$79.05
Present Value @	$11.67	$14.21	$16.72	$18.87	$21.15	$22.03	$26.13	$26.15
Cumulative Present Value:	($66)	($52)	($35)	($16)	$5	$27	$53	$79

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

13 **Minimum % Gain On Sale To Ratepay**

PPL Cost ; RAMPP5 Value Revised 12/31/99	2016	2017	2018	2019	2020	2021	2022	2023
Non-fuel Revenue Requirement	$47,996	$48,854	$49,854	$51,028	$52,013	$52,367	$52,034	$52,607
Unit 1 Fuel	$52,241	$53,914	$55,720	$57,113	$58,541	$60,005	$61,505	$63,042
Unit 2 Fuel	$51,780	$53,184	$54,958	$56,332	$57,740	$59,184	$60,664	$62,180
Total	$152,016	$155,952	$160,532	$164,474	$168,295	$171,556	$174,203	$177,830
PP&L Share of Output	4,216,546	4,229,946	4,234,950	4,234,950	4,234,950	4,234,950	4,234,950	4,234,950
Ownership / Operating cost mills/kwh	36.05	36.87	37.91	38.84	39.74	40.51	41.13	41.99
Ownership / Operating cost mills/kwh	36.05	36.87	37.91	38.84	39.74	40.51	41.13	41.99
PP&L RAMPP 5 Forecast	41.5	42.9	44.4	45.9	47.4	49.1	50.7	52.4
Dispatch Benefit proportioned @ 1.71 m	3.10	3.20	3.32	3.43	3.54	3.67	3.79	3.91
Value with Dispatch Benefit	44.60	46.10	47.72	49.33	50.94	52.77	54.49	56.31
Add 1.00 mills capacity benefit uninflate	45.60	47.10	48.72	50.33	51.94	53.77	55.49	57.31
Output mwh @ 100% of Plant	8,876,939	8,905,149	8,915,685	8,915,685	8,915,685	8,915,685	8,915,685	8,915,685
Cost of Power ($Millions)	$320.03	$328.32	$337.96	$346.26	$354.30	$361.17	$366.74	$374.38
Value of Power ($Millions)	$395.90	$410.56	$425.42	$439.79	$454.16	$470.45	$485.78	$502.07
Cost/Value of Sulphur Credits	($6.90)	($6.89)	($6.89)	($6.89)	($6.89)	($6.89)	($6.89)	($6.89)
Net Value of Plant vs. Market:	$82.77	$89.13	$94.34	$100.42	$106.75	$116.17	$125.93	$134.58
Present Value @	$25.54	$25.67	$25.36	$25.19	$24.98	$25.37	$25.67	$25.60
Cumulative Present Value:	$105	$130	$156	$181	$206	$231	$257	$282

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

(14) **Minimum % Gain On Sale To Ratepay**

PPL Cost ; RAMPP5 Value

Revised 12/31/99	2024	2025
Non-fuel Revenue Requirement	$53,923	$55,271
Unit 1 Fuel	$64,619	$66,234
Unit 2 Fuel	$63,735	$65,328
Total	$182,276	$186,833
PP&L Share of Output	4,234,950	4,234,950
Ownership / Operating cost mills/kwh	43.04	44.12
Ownership / Operating cost mills/kwh	43.04	44.12
PP&L RAMPP 5 Forecast	54.2	56.0
Dispatch Benefit proportioned @ 1.71 m	4.05	4.18
Value with Dispatch Benefit	58.25	60.18
Add 1.00 mills capacity benefit uninflate	59.20	61.15
Output mwh @ 100% of Plant	8,915,685	8,915,685
Cost of Power ($Millions)	$382	$390
Value of Power ($Millions)	$519	$536
Cost/Value of Sulphur Credits	($7)	($7)
Net Value of Plant vs. Market:	$143.62	$153.06
Present Value @	$25.49	$25.35
Cumulative Present Value:	$308	$333

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

15 **Minimum % Gain On Sale To Ratepay**

PSE Value, Colstrip Case Based Value
Revised 12/31/99

	Source	2000	2001	2002	2003	2004	2005	2006
Puget Estimate of Cost of Centralia	Puget	24.98	27.41	31.41	30.95	31.75	31.98	32.25
Aurora Forecast from PSE / Colstrip	PSE	21.44	23.12	24.55	27.00	28.75	31.14	32.76
Extrapolate after forecast	PP&L							
Aurora to 2017; Extrapolate After		21.44	23.12	24.55	27.00	28.75	31.14	32.76
Dispatch Benefit proportioned @ 1.71 mills		1.71	1.84	1.96	2.15	2.29	2.48	2.61
Value with Dispatch Benefit	Avista	23.15	24.96	26.51	29.15	31.04	33.62	35.37
Add 1.00 mills capacity benefit uninflate	Avista	24.15	25.96	27.51	30.15	32.04	34.62	36.37
Output mwh @ 100% of Plant	PP&L	8,153,836	8,162,520	8,142,498	8,197,625	8,147,469	8,095,221	8,374,583
Cost of Power ($Millions)		$203.72	$223.76	$255.74	$253.70	$258.69	$258.85	$270.07
Value of Power ($Millions)		$188.76	$203.77	$215.84	$238.99	$252.92	$272.19	$296.23
Cost/Value of Sulphur Credits		$9.78	$10.10	$1.99	($6.61)	($6.82)	($7.03)	($6.96)
Net Value of Plant vs. Market:		($24.75)	($30.09)	($41.90)	($8.10)	$1.04	$20.38	$33.13
Present Value @	0.0716	($23.09)	($26.20)	($34.05)	($6.15)	$0.74	$13.46	$20.42

	Source			
		24 Years	26 Years	
Gain on Sale Required for Breakeven:		$466.14	$510.76	
Book Value, Plant:	Avista	$116.51	$116.51	
Book Value, Mine:	PP&L	$107.20	$107.20	223.713333
Total Sale Price Required:		**$689.85**	**$734.48**	
Actual Sale Price:	PP&L	$554.00	$554.00	
Minimum % Gain On Sale To Ratepayers		**141.13%**	**154.64%**	

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PSE Value, Colstrip Case Based Value
Revised 12/31/99

	2007	2008	2009	2010	2011	2012	2013	2014
Puget Estimate of Cost of Centralia	32.89	33.19	33.49	33.78	32.64	33.48	33.92	34.46
Aurora Forecast from PSE / Colstrip	34.71	37.06	38.25	37.95	39.26	39.97	39.16	42.42
Extrapolate after forecast								
Aurora to 2017; Extrapolate After	34.71	37.06	38.25	37.95	39.26	39.97	39.16	42.42
Dispatch Benefit proportioned @ 1.71 m	2.77	2.96	3.05	3.03	3.13	3.19	3.12	3.38
Value with Dispatch Benefit	37.48	40.02	41.30	40.98	42.39	43.16	42.28	45.80
Add 1.00 mills capacity benefit uninflate	38.48	41.02	42.30	41.98	43.39	44.16	43.28	46.80
Output mwh @ 100% of Plant	8,342,488	8,455,950	8,476,854	8,583,231	8,698,377	8,851,300	8,876,077	8,876,710
Cost of Power ($Millions)	$274.35	$280.63	$283.89	$289.93	$283.89	$296.34	$301.07	$305.89
Value of Power ($Millions)	$312.66	$338.37	$350.10	$351.71	$368.74	$382.00	$375.31	$406.58
Cost/Value of Sulphur Credits	($6.97)	($6.94)	($6.94)	($6.91)	($6.94)	($6.91)	($6.90)	($6.90)
Net Value of Plant vs. Market:	$45.28	$64.69	$73.15	$68.70	$91.79	$92.57	$81.14	$107.59
Present Value @	$26.04	$34.72	$36.63	$32.11	$40.03	$37.67	$30.82	$38.13

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepay

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PSE Value, Colstrip Case Based Value
Revised 12/31/99

	2015	2016	2017	2018	2019	2020	2021	2022
Puget Estimate of Cost of Centralia	34.96	35.50	36.49	44.29	38.34	39.30	40.28	41.29
Aurora Forecast from PSE / Colstrip	42.46	43.79	44.43					
Extrapolate after forecast				45.54	46.68	47.85	49.04	50.27
Aurora to 2017; Extrapolate After	42.46	43.79	44.43	45.54	46.68	47.85	49.04	50.27
Dispatch Benefit proportioned @ 1.71 m	3.39	3.49	3.54	3.63	3.72	3.82	3.91	4.01
Value with Dispatch Benefit	45.85	47.28	47.97	49.17	50.40	51.66	52.95	54.28
Add 1.00 mills capacity benefit uninflate	46.85	48.28	48.97	50.17	51.40	52.66	53.95	55.28
Output mwh @ 100% of Plant	8,877,591	8,876,939	8,905,149	8,915,685	8,915,685	8,915,685	8,915,685	8,915,685
Cost of Power ($Millions)	$310.35	$315.11	$324.95	$394.92	$341.81	$350.35	$359.11	$368.09
Value of Power ($Millions)	$407.01	$419.72	$427.21	$438.41	$449.37	$460.61	$472.12	$483.92
Cost/Value of Sulphur Credits	($6.90)	($6.90)	($6.89)	($6.89)	($6.89)	($6.89)	($6.89)	($6.89)
Net Value of Plant vs. Market:	$103.55	$111.52	$109.15	$50.38	$114.45	$117.14	$119.90	$122.72
Present Value @	$34.25	$34.42	$31.44	$13.54	$28.71	$27.42	$26.19	$25.01

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepay

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PSE Value, Colstrip Case Based Value
Revised 12/31/99

	2023	2024	2025
Puget Estimate of Cost of Centralia	42.32	43.38	44.46
Aurora Forecast from PSE / Colstrip			
Extrapolate after forecast	51.53	52.81	54.13
Aurora to 2017; Extrapolate After	51.53	52.81	54.13
Dispatch Benefit proportioned @ 1.71 m	4.11	4.21	4.32
Value with Dispatch Benefit	55.63	57.03	58.45
Add 1.00 mills capacity benefit uninflate	56.63	58.02	59.45
Output mwh @ 100% of Plant	8,915,685	8,915,685	8,915,685
Cost of Power ($Millions)	$377.29	$387	$396
Value of Power ($Millions)	$496.02	$508	$521
Cost/Value of Sulphur Credits	($6.89)	($7)	($7)
Net Value of Plant vs. Market:	$125.62	$128.59	$131.63
Present Value @	$23.89	$23	$22

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepay

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WWP Scenario											
Using PC #19 Forecast		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Cost of Centralia Power		26.45	28.93	30.33	30.60	30.87	31.15	31.43	31.72	32.02	32.33
Value of Flat Power		26.5	27.04	27.29	27.54	27.79	28.04	28.29	30.29	32.29	34.29
Plus Dispatch Benefit	6.45%	1.71	1.74	1.76	1.78	1.79	1.81	1.83	1.95	2.08	2.21
Plus Capacity Benefit		1	1	1	1	1	1	1	1	1	1
Total Value of Centralia Pc		29.21	29.78485	30.05098	30.31711	30.58324	30.84937	31.11551	33.24456	35.37362	37.50268
Generation per WWP		1220800	1220800	1220800	1220800	1220800	1220800	1220800	1220800	1220800	1220800
Adjust to 100%	15.00%	8138667	8138667	8138667	8138667	8138667	8138667	8138667	8138667	8138667	8138667
Direct Cost of Centralia Po		$215.29	$235.45	$246.89	$249.04	$251.27	$253.49	$255.78	$258.14	$260.58	$263.09
Sulphur Cost/Credits from a		$9.78	$10.10	$1.99	($6.61)	($6.82)	($7.03)	($6.96)	($6.97)	($6.94)	($6.94)
Total Cost of Centralia Pov		$225.08	$245.55	$248.88	$242.43	$244.46	$246.46	$248.81	$251.17	$253.63	$256.15
Value Without Sulphur Cre		$237.73	$242.41	$244.57	$246.74	$248.91	$251.07	$253.24	$270.57	$287.89	$305.22
Net Value over Cost:		$12.66	($3.14)	($4.30)	$4.31	$4.45	$4.62	$4.43	$19.40	$34.26	$49.07
Present Value	0.0716	$11.81	($2.74)	($3.50)	$3.27	$3.15	$3.05	$2.73	$11.16	$18.39	$24.58

	24 Years	26 Years
Gain on Sale Required for	$476	$520.58
Book Value, Plant:	$116.51	$116.51
Book Value, Mine:	$107.20	$107.20
Total Sale Price Requirec	**$699.60**	**$744.30**
Actual Sale Price:	$554.00	$554.00
Minimum % Gain On Salı	**144.08%**	**157.62%**

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WWP Scenario											
Using PC #19 Forecast	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Cost of Centralia Power	32.64	32.97	33.31	33.66	34.01	34.38	34.76	35.15	35.55	35.88	35.50
		Extrapolate value @ 2.5%									
Value of Flat Power	36.29	37.20	38.13	39.08	40.06	41.06	42.09	43.14	44.22	45.32	46.45
Plus Dispatch Benefit	2.34	2.40	2.46	2.52	2.58	2.65	2.72	2.78	2.85	2.92	3.00
Plus Capacity Benefit	1	1	1	1	1	1	1	1	1	1	1
Total Value of Centralia Pc	39.63173	40.59753	41.58746	42.60215	43.6422	44.70826	45.80097	46.92099	48.06901	49.24574	50.45188
Generation per WWP	1220800	1220800	1220800	1220800	1220800	1220800	1220800	1220800	1220800	1220800	1220800
Adjust to 100%	8138667	8138667	8138667	8138667	8138667	8138667	8138667	8138667	8138667	8138667	8138667
Direct Cost of Centralia Po	$265.67	$268.34	$271.09	$273.91	$276.82	$279.82	$282.90	$286.07	$289.33	$292.03	$288.93
Sulphur Cost/Credits from	($6.91)	($6.94)	($6.91)	($6.90)	($6.90)	($6.90)	($6.90)	($6.89)	($6.89)	($6.89)	($6.89)
Total Cost of Centralia Pov	$258.76	$261.40	$264.18	$267.01	$269.92	$272.92	$276.00	$279.18	$282.44	$285.14	$282.04
Value Without Sulphur Cre	$322.55	$330.41	$338.47	$346.72	$355.19	$363.87	$372.76	$381.87	$391.22	$400.79	$410.61
Net Value over Cost:	$63.79	$69.01	$74.29	$79.71	$85.26	$90.95	$96.76	$102.70	$108.78	$115.65	$128.57
Present Value	$29.81	$30.10	$30.23	$30.27	$30.22	$30.08	$29.86	$29.58	$29.24	$29.01	$30.09

Gain on Sale Required for
Book Value, Plant:
Book Value, Mine:
Total Sale Price Requirec
Actual Sale Price:

Minimum % Gain On Sal(

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WWP Scenario

Using PC #19 Forecast	2021	2022	2023	2024	2025
Cost of Centralia Power	37.70	38.64	39.61	40.60	41.61
	Extrapolate beyond 2020 @ 2.5%				
Value of Flat Power	47.62	48.81	50.03	51.28	52.56
Plus Dispatch Benefit	3.07	3.15	3.23	3.31	3.39
Plus Capacity Benefit	1	1	1	1	1
Total Value of Centralia Pc	51.68818	52.95538	54.25427	55.58563	56.95027
Generation per WWP	1220800	1220800	1220800	1220800	1220800
Adjust to 100%	8138667	8138667	8138667	8138667	8138667
Direct Cost of Centralia Po	$306.81	$314.48	$322.35	$330.41	$338.67
Sulphur Cost/Credits from	($6.89)	($6.89)	($6.89)	($6.89)	($6.89)
Total Cost of Centralia Pov	$299.92	$307.60	$315.46	$323.52	$331.78
Value Without Sulphur Cre	$420.67	$430.99	$441.56	$452.39	$463.50
Net Value over Cost:	$120.75	$123.39	$126.10	$128.88	$131.72
Present Value	$26.37	$25.15	$23.98	$22.87	$21.82

Gain on Sale Required for
Book Value, Plant:
Book Value, Mine:
Total Sale Price Requirec
Actual Sale Price:

Minimum % Gain On Sal

22

Workpape Workpaper to Exhibit 504

Fixed Cos	Fixed Costs	Plant	Accum Dep	Net	Rate	Cost	Depr	Total Cost	WWP Million kwh	WWP Mills/kwh
1986	1986	$46.90	$18.80	$28.10	0.14	3.934	1.3	5.234	613	8.538336
1987	1987	$47.40	$20.10	$27.30	0.14	3.822	1.5	5.322	1327	4.01055
1988	1988	$48.00	$21.60	$26.40	0.14	3.696	1.4	5.096	1244	4.096463
1989	1989	$48.70	$23.00	$25.70	0.14	3.598	1.6	5.198	1294	4.017002
1990	1990	$49.20	$24.60	$24.60	0.14	3.444	1.1	4.544	1093	4.157365
1991	1991	$49.90	$25.70	$24.20	0.14	3.388	1.7	5.088	1162	4.378657
1992	1992	$51.60	$27.40	$24.20	0.12	2.904	1.8	4.704	1328	3.542169
1993	1993	$52.70	$29.20	$23.50	0.12	2.82	1.9	4.72	1256	3.757962
1994	1994	$53.90	$31.10	$22.80	0.12	2.736	1.5	4.236	1429	2.964311
1995	1995	$54.00	$32.60	$21.40	0.12	2.568	1.9	4.468	771	5.795071
1996	1996	$54.30	$34.50	$19.80	0.12	2.376	1.5	3.876	1267	3.059195
1997	1997	$55.60	$36.00	$19.60	0.12	2.352	1.6	3.952	1021	3.870715
1998	1998	$55.70	$37.60	$18.10	0.12	2.172	1.6	3.772	1282	2.942278

Return Foı Return Formula:

U-86-99 U-86-99

Debt	Debt	9.00%	48.00%	4.32%	0.02808	Capital structure and cost rates guesstimated
Preferred	Preferred	10.50%	15.00%	1.58%	0.01575	Settlement had no capital structure
Equity	Equity	12.90%	37.00%	4.77%	0.04773	
				10.67%	0.09156	
					0.14086154	Capital Recovery Factor old case

Debt	Debt	8.00%	48.00%	3.84%	0.02496	
Preferred	Preferred	9.00%	15.00%	1.35%	0.0135	Rough update as of 1992 WNG/PSD Cases
Equity	Equity	10.50%	37.00%	3.89%	0.03885	
				9.08%	0.07731	

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Carbon Tax in 2008 PP&L Cost of Power
NWPPC Aurora Value of Power
Revised 12/31/99

	Source	2000	2001	2002	2003	2004	2005
Non-fuel Revenue Requirement	PP&L	$34,328	$44,764	$49,658	$45,177	$47,159	$46,646
Unit 1 Fuel	PP&L	$33,114	$33,651	$33,973	$34,734	$35,273	$36,059
Unit 2 Fuel	PP&L	$32,939	$33,604	$34,565	$35,549	$35,143	$36,551
Total		$100,380	$112,019	$118,196	$115,460	$117,575	$119,257
PP&L Share of Output	PP&L	3,873,072	3,877,197	3,867,687	3,893,872	3,870,048	3,845,230
Ownership / Operating cost mills/kwh	PP&L	25.92	28.89	30.56	29.65	30.38	31.01
Aurora Forecast from NWPPC	NWPPC	26.92	27.59	29.05	31.74	34.10	35.11
Extrapolation Beyond Forecast @ 2.5%							
Value of Power Before Shaping:		26.92	27.59	29.05	31.74	34.10	35.11
Assumption below is from Avista							
Add 1.71 mills dispatch benefit	Avista	28.63	29.30	30.76	33.45	35.81	36.82
Add 1.00 mills capacity benefit	Avista	29.63	30.30	31.76	34.45	36.81	37.82
Output mwh @ 100% of Plant	PP&L	8,153,836	8,162,520	8,142,498	8,197,625	8,147,469	8,095,221
Carbon Tax:							
Cost of Power ($Millions)		$211.33	$235.83	$248.83	$243.07	$247.53	$251.07
Value of Power ($Millions)		$233.47	$239.15	$250.45	$274.20	$291.77	$298.03
Cost/Value of Sulphur Credits		$9.78	$10.10	$1.99	($6.61)	($6.82)	($7.03)
Net Value of Plant vs. Market:.		$12.36	($6.77)	($0.38)	$37.74	$51.06	$54.00
Present Value @	0.0716	$11.53	($5.90)	($0.31)	$28.62	$36.14	$35.66

Carbon Tax Assumption:
$10/ton
=10.57 mills/kwh coal
= 3.91 mills/kwh gas
Difference = 6.66 mills/kwh

		24 Years	26 Years
Gain on Sale Required for Breakeven:		$378.22	$401.50
Book Value, Plant:	Avista	$116.51	$116.51
Book Value, Mine:	PP&L	$107.20	$107.20
Total Sale Price Required:		**$601.93**	**$625.22**
Actual Sale Price:	PP&L	$554.00	$554.00

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Carbon Tax in 2008 PP&L Cost of Power
NWPPC Aurora Value of Power
Revised 12/31/99

	2006	2007	2008	2009	2010	2011
Non-fuel Revenue Requirement	$46,435	$46,180	$49,845	$49,860	$49,954	$50,084
Unit 1 Fuel	$38,322	$39,114	$40,280	$41,380	$42,684	$44,373
Unit 2 Fuel	$38,331	$39,010	$40,971	$41,805	$43,503	$45,034
Total	$123,088	$124,304	$131,096	$133,045	$136,140	$139,491
PP&L Share of Output	3,977,927	3,962,682	4,016,576	4,026,506	4,077,035	4,131,729
Ownership / Operating cost mills/kwh	30.94	31.37	32.64	33.04	33.39	33.76
Aurora Forecast from NWPPC	36.44	37.69	38.90	39.45	40.46	40.03
Extrapolation Beyond Forecast @ 2.5%						
Value of Power Before Shaping:	36.44	37.69	38.90	39.45	40.46	40.03
Assumption below is from Avista						
Add 1.71 mills dispatch benefit	38.15	39.40	40.61	41.16	42.17	41.74
Add 1.00 mills capacity benefit	39.15	40.40	41.61	42.16	43.17	42.74
Output mwh @ 100% of Plant	8,374,583	8,342,488	8,455,950	8,476,854	8,583,231	8,698,377
Carbon Tax:			56.32	56.46	57.16	57.93
Cost of Power ($Millions)	$259.13	$261.69	$332.31	$336.55	$343.78	$351.60
Value of Power ($Millions)	$319.51	$328.65	$343.43	$348.90	$361.92	$363.07
Cost/Value of Sulphur Credits	($6.96)	($6.97)	($6.94)	($6.94)	($6.91)	($6.94)
Net Value of Plant vs. Market:	$67.35	$73.93	$18.07	$19.29	$25.06	$18.41
Present Value @	$41.50	$42.52	$9.70	$9.66	$11.71	$8.03

Carbon Tax Assumption:
$10/ton
=10.57 mills/kwh coal
= 3.91 mills/kwh gas
Difference = 6.66 mills/kwh

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

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Carbon Tax in 2008 PP&L Cost of Power
NWPPC Aurora Value of Power
Revised 12/31/99

	2012	2013	2014	2015	2016	2017
Non-fuel Revenue Requirement	$50,289	$50,524	$46,504	$47,201	$47,996	$48,854
Unit 1 Fuel	$46,681	$47,999	$49,231	$50,587	$52,241	$53,914
Unit 2 Fuel	$46,545	$47,562	$48,785	$50,115	$51,780	$53,184
Total	$143,516	$146,085	$144,521	$147,903	$152,016	$155,952
PP&L Share of Output	4,204,368	4,216,136	4,216,437	4,216,856	4,216,546	4,229,946
Ownership / Operating cost mills/kwh	34.13	34.65	34.28	35.07	36.05	36.87
Aurora Forecast from NWPPC	41.51	42.96	43.21	44.62	44.65	46.38
Extrapolation Beyond Forecast @ 2.5%						45.76
Value of Power Before Shaping:	41.51	42.96	43.21	44.62	44.65	45.76
Assumption below is from Avista						
Add 1.71 mills dispatch benefit	43.22	44.67	44.92	46.33	46.36	47.47
Add 1.00 mills capacity benefit	44.22	45.67	45.92	47.33	47.36	48.47
Output mwh @ 100% of Plant	8,851,300	8,876,077	8,876,710	8,877,591	8,876,939	8,905,149
Carbon Tax:	58.95	59.11	59.12	59.12	59.12	59.31
Cost of Power ($Millions)	$361.09	$366.66	$363.37	$370.50	$379.15	$387.63
Value of Power ($Millions)	$382.55	$396.52	$398.72	$411.33	$411.51	$422.75
Cost/Value of Sulphur Credits	($6.91)	($6.90)	($6.90)	($6.90)	($6.90)	($6.89)
Net Value of Plant vs. Market:	$28.37	$36.75	$42.24	$47.73	$39.25	$42.02
Present Value @	$11.55	$13.96	$14.97	$15.79	$12.11	$12.10

Carbon Tax Assumption:
$10/ton
=10.57 mills/kwh coal
= 3.91 mills/kwh gas
Difference = 6.66 mills/kwh

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

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Carbon Tax in 2008 PP&L Cost of Power
NWPPC Aurora Value of Power
Revised 12/31/99

	2018	2019	2020	2021	2022	2023
Non-fuel Revenue Requirement	$49,854	$51,028	$52,013	$52,367	$52,034	$52,607
Unit 1 Fuel	$55,720	$57,113	$58,541	$60,005	$61,505	$63,042
Unit 2 Fuel	$54,958	$56,332	$57,740	$59,184	$60,664	$62,180
Total	$160,532	$164,474	$168,295	$171,556	$174,203	$177,830
PP&L Share of Output	4,234,950	4,234,950	4,234,950	4,234,950	4,234,950	4,234,950
Ownership / Operating cost mills/kwh	37.91	38.84	39.74	40.51	41.13	41.99
Aurora Forecast from NWPPC	*50.1*	*51.3*	*52.6*	*53.9*	*55.3*	*56.7*
Extrapolation Beyond Forecast @ 2.5%	46.91	48.08	49.28	50.51	51.78	53.07
Value of Power Before Shaping:	46.91	48.08	49.28	50.51	51.78	53.07
Assumption below is from Avista						
Add 1.71 mills dispatch benefit	48.62	49.79	50.99	52.22	53.49	54.78
Add 1.00 mills capacity benefit	49.62	50.79	51.99	53.22	54.49	55.78
Output mwh @ 100% of Plant	8,915,685	8,915,685	8,915,685	8,915,685	8,915,685	8,915,685
Carbon Tax:	59.38	59.38	59.38	59.38	59.38	59.38
Cost of Power ($Millions)	$397.34	$405.64	$413.68	$420.55	$426.12	$433.76
Value of Power ($Millions)	$433.45	$443.91	$454.63	$465.61	$476.87	$488.41
Cost/Value of Sulphur Credits	($6.89)	($6.89)	($6.89)	($6.89)	($6.89)	($6.89)
Net Value of Plant vs. Market:	$43.00	$45.16	$47.83	$51.95	$57.64	$61.54
Present Value @	$11.56	$11.33	$11.20	$11.35	$11.75	$11.71

Carbon Tax Assumption:
$10/ton
=10.57 mills/kwh coal
= 3.91 mills/kwh gas
Difference = 6.66 mills/kwh

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

27

Carbon Tax in 2008 PP&L Cost of Power
NWPPC Aurora Value of Power
Revised 12/31/99

	2024	2025
Non-fuel Revenue Requirement	$53,923	$55,271
Unit 1 Fuel	$64,619	$66,234
Unit 2 Fuel	$63,735	$65,328
Total	$182,276	$186,833
PP&L Share of Output	4,234,950	4,234,950
Ownership / Operating cost mills/kwh	43.04	44.12
Aurora Forecast from NWPPC	*58.1*	*59.5*
Extrapolation Beyond Forecast @ 2.5%	54.40	55.76
Value of Power Before Shaping:	54.40	55.76
Assumption below is from Avista		
Add 1.71 mills dispatch benefit	56.11	57.47
Add 1.00 mills capacity benefit	57.11	58.47
Output mwh @ 100% of Plant	8,915,685	8,915,685
Carbon Tax:	59.38	59.38
Cost of Power ($Millions)	$443.12	$452.71
Value of Power ($Millions)	$500	$512
Cost/Value of Sulphur Credits	($7)	($7)
Net Value of Plant vs. Market:	$64.00	$66.52
Present Value @	$12	$12

Carbon Tax Assumption:
$10/ton
=10.57 mills/kwh coal
= 3.91 mills/kwh gas
Difference = 6.66 mills/kwh

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

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ANNUAL AVERAGE HUB PRICES

CASE: B10 (11_29)
Nominal Prices ($/MWh):

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
CalPX	20.91	25.14	26.89	27.42	28.97	31.39	33.68	35.08	36.64	38.26
COB	20.63	24.92	26.60	27.23	28.82	31.42	33.90	35.17	36.67	38.15
Four Corners	19.70	23.48	24.97	25.34	26.83	29.20	31.41	32.83	34.28	36.01
Mead	19.94	23.74	25.39	25.86	27.40	29.86	32.13	33.49	34.96	36.84
Mid-Columbia	19.49	23.66	25.26	25.87	27.44	29.95	32.37	33.58	34.96	36.30
Palo Verde	21.16	25.31	27.00	27.56	29.15	31.64	33.92	35.24	36.80	38.59

ANNUAL AVERAGE AREA PRICES

CASE: B10 (11_29)
Nominal Prices ($/MWh):

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Alberta	23.76	28.89	29.46	29.06	29.95	32.99	35.69	36.02	37.03	37.02
Arizona & Southern Nevada	19.01	22.76	24.26	24.65	26.11	28.48	30.62	31.90	33.32	35.07
British Columbia	22.15	27.26	28.32	28.27	29.62	32.43	35.03	35.22	36.18	35.99
Colorado	18.32	22.01	23.55	24.29	25.91	28.41	30.89	32.37	33.95	35.60
Eastern OR & WA & Northern ID	19.49	23.66	25.26	25.87	27.44	29.95	32.37	33.58	34.96	36.30
Montana	18.70	22.68	24.26	24.91	26.49	28.98	31.46	32.84	34.33	35.72
New Mexico	18.88	22.47	23.91	24.25	25.74	28.00	30.13	31.54	32.93	34.57
Northern California	20.48	25.00	26.75	27.22	28.56	31.09	33.41	34.67	36.24	37.78
Northern Nevada	19.75	23.69	25.37	25.89	27.36	29.81	32.17	33.48	34.94	36.56
Southern California	20.17	24.14	25.82	26.36	27.91	30.26	32.49	33.81	35.38	37.04
Southern Idaho	19.02	23.00	24.61	25.22	26.78	29.28	31.72	33.13	34.65	36.09
Southwestern Public Service -- SPP	20.49	24.36	25.95	26.96	29.10	31.96	34.75	37.11	39.93	37.86
Utah	18.59	22.37	23.97	24.62	26.17	28.64	30.98	32.38	33.90	35.52
Western Oregon & Washington	20.54	25.26	26.92	27.59	29.05	31.74	34.10	35.11	36.44	37.69
Wyoming	18.06	21.70	23.24	23.98	25.58	28.00	30.42	31.88	33.43	34.99

Northwest Power Planning Council Aurora Foı

ANNUAL AVERAGE HUB PRIC

CASE:
Nominal Prices ($/MWh):

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
CalPX	39.86	41.07	42.15	42.41	44.12	45.62	46.43	47.65	48.25	49.78
COB	39.46	40.24	41.42	41.66	43.60	45.19	45.85	47.11	47.67	49.14
Four Corners	37.62	38.80	40.01	40.55	42.32	43.87	44.85	46.26	46.98	48.79
Mead	38.34	39.49	40.53	40.75	42.65	44.26	45.00	46.29	46.71	48.39
Mid-Columbia	37.53	38.14	39.08	38.73	40.27	41.72	41.98	43.30	43.33	44.94
Palo Verde	40.15	41.39	42.42	42.68	44.12	45.40	46.15	47.45	48.12	49.68

ANNUAL AVERAGE AREA PRI

CASE:
Nominal Prices ($/MWh):

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alberta	38.76	38.39	39.88	39.68	41.90	43.18	42.64	44.11	44.13	46.75
Arizona & Southern Nevada	36.68	37.83	38.96	39.49	41.22	42.80	43.73	45.09	45.86	47.65
British Columbia	37.71	37.07	38.47	38.12	40.14	41.14	40.81	41.91	42.14	44.55
Colorado	37.18	38.27	39.38	40.06	42.29	44.18	45.40	47.01	47.19	48.83
Eastern OR & WA & Northern ID	37.53	38.14	39.08	38.73	40.27	41.72	41.98	43.30	43.33	44.94
Montana	36.89	37.53	38.44	38.13	39.78	41.34	41.61	42.93	43.00	44.56
New Mexico	36.15	37.24	38.40	38.87	40.67	42.20	43.12	44.48	45.25	47.07
Northern California	39.05	39.99	41.13	41.45	43.33	44.93	45.52	46.73	47.42	48.80
Northern Nevada	37.99	38.96	39.95	40.13	42.04	43.65	44.43	45.81	46.25	47.90
Southern California	38.59	39.79	40.78	41.04	42.65	44.02	44.73	45.90	46.43	47.91
Southern Idaho	37.46	38.20	39.17	39.16	40.99	42.64	43.38	44.85	45.07	46.66
Southwestern Public Service -- SPP	39.82	41.11	42.12	40.11	42.71	45.17	44.14	43.89	45.76	48.22
Utah	36.98	37.94	38.87	39.06	41.05	42.73	43.61	45.09	45.25	46.84
Western Oregon & Washington	38.90	39.45	40.46	40.03	41.51	42.96	43.21	44.62	44.65	46.38
Wyoming	36.33	37.05	37.99	38.01	39.95	41.67	42.34	43.77	43.79	45.26

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Workpape Workpaper to Exhibit 504

Fixed Cos Fixed Costs

		Plant	Accum Dep	Net	Rate	Cost	Depr	Total Cost	WWP Million kwh	WWP Mills/kwh
1986	1986	$46.90	$18.80	$28.10	0.14	3.934	1.3	5.234	613	8.538336
1987	1987	$47.40	$20.10	$27.30	0.14	3.822	1.5	5.322	1327	4.01055
1988	1988	$48.00	$21.60	$26.40	0.14	3.696	1.4	5.096	1244	4.096463
1989	1989	$48.70	$23.00	$25.70	0.14	3.598	1.6	5.198	1294	4.017002
1990	1990	$49.20	$24.60	$24.60	0.14	3.444	1.1	4.544	1093	4.157365
1991	1991	$49.90	$25.70	$24.20	0.14	3.388	1.7	5.088	1162	4.378657
1992	1992	$51.60	$27.40	$24.20	0.12	2.904	1.8	4.704	1328	3.542169
1993	1993	$52.70	$29.20	$23.50	0.12	2.82	1.9	4.72	1256	3.757962
1994	1994	$53.90	$31.10	$22.80	0.12	2.736	1.5	4.236	1429	2.964311
1995	1995	$54.00	$32.60	$21.40	0.12	2.568	1.9	4.468	771	5.795071
1996	1996	$54.30	$34.50	$19.80	0.12	2.376	1.5	3.876	1267	3.059195
1997	1997	$55.60	$36.00	$19.60	0.12	2.352	1.6	3.952	1021	3.870715
1998	1998	$55.70	$37.60	$18.10	0.12	2.172	1.6	3.772	1282	2.942278

Return Foı Return Formula:

U-86-99 U-86-99

Debt	Debt	9.00%	48.00%	4.32%	0.02808	Capital structure and cost rates guesstimated
Preferred	Preferred	10.50%	15.00%	1.58%	0.01575	Settlement had no capital structure
Equity	Equity	12.90%	37.00%	4.77%	0.04773	
				10.67%	0.09156	
					0.14086154	Capital Recovery Factor old case

Debt	Debt	8.00%	48.00%	3.84%	0.02496	
Preferred	Preferred	9.00%	15.00%	1.35%	0.0135	Rough update as of 1992 WNG/PSD Cases

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Exhibit 513 Submitted by Public Counsel Wednesday, January 19, 2000

Exhibit 513 is responsive to the direction given by the Hearing Examiner at page 770 of the transcript.

Pages 2-4 replace the graphs which appear at page 3, 5, and 24 of Mr. Lazar's testimony, Exhibit T-500. The remaining pages correct pages 1, 2, 4, and 7-12 of Exhibit 501.

Two corrections to the analysis of Mr. Lazar, identified in the record, are reflected in Exhibit 513.

First, at Tr. 697, Mr. Lazar accepted that the value of power he represented as being Puget's estimates from the "Colstrip" proceeding were shifted by one year. Mr. Lazar has checked this, and Mr. Harris was correct. This data appears in the column marked "Aurora Colstrip PSE" on page 2 of Exhibit 501, and was also used to calculated Scenario 6 on page 1 of Exhibit 501. The magnitude of this correction is to increase the present value of the plant and minimum required sale price by approximately $170 million.

Second, at Tr. 749, Mr. Lazar accepted (and checked on the stand) that he had omitted the 1 mill capacity adder in computing the value of power in his Exhibit 501, Pages 7-12. This error persisted in several of the scenarios, carrying forward to Page 1 of Exhibit 501, where the results are summarized. Page 5 of Exhibit 513, in the same format as Page 1 of Exhibit 501, has corrected for this error in each of the scenarios in which it occurred, which is all except Scenarios 6 and 8. The magnitude of this correction is to increase the present value of the plant and minimum required sale price by approximately $100 million, but this amount varies slightly with each scenario.

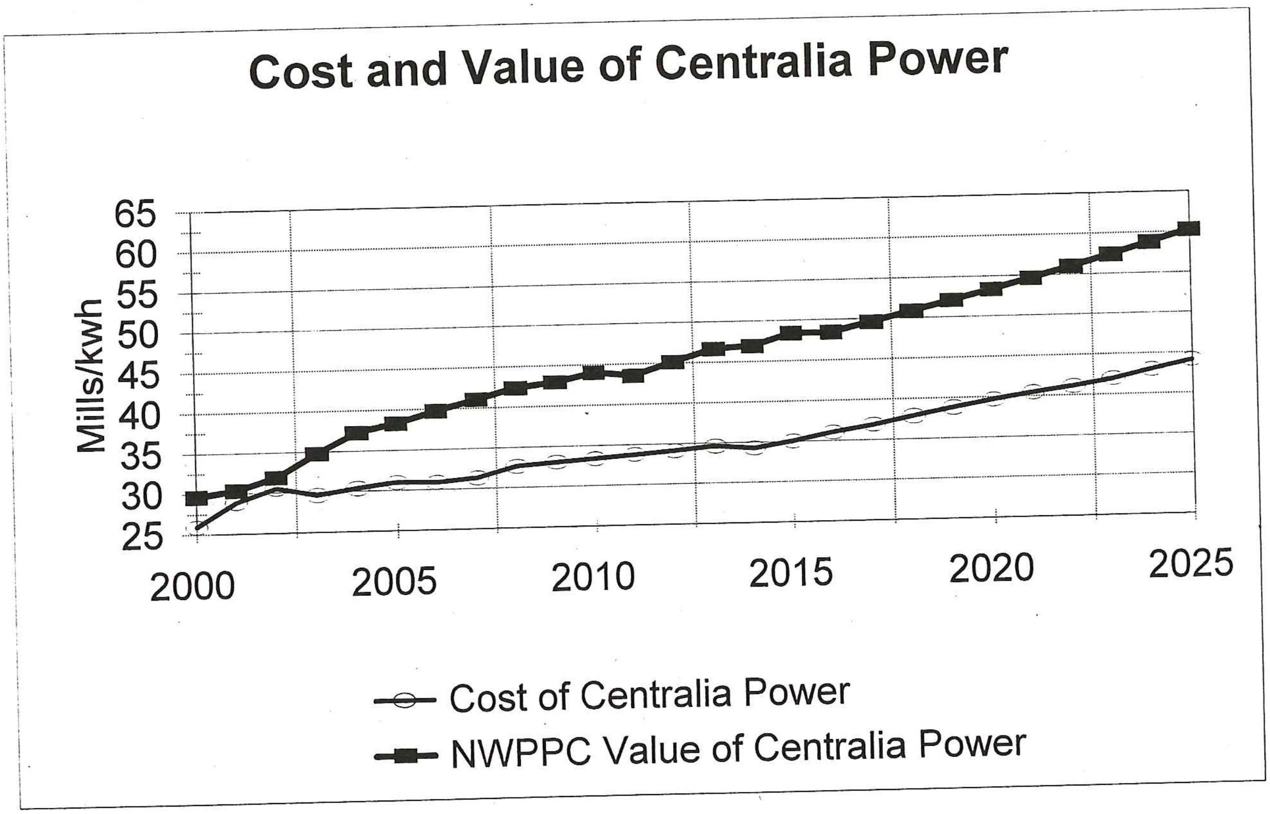
Pages 7 and 8 of Exhibit 513 are corrections of pages 4 and 6 of Exhibit 501, reflecting the corrections noted above. Pages 9-14 of Exhibit 513 correct pages 7-12 of Exhibit 501 for Mr. Lazar's Base Analysis to reflect the error identified by the Hearing Examiner at Tr. 749.

Ex. 513 therefore consists of the following pages:

Page	Description
1	This page
2	Replacement graph for page 3 of Ex. T-500
3	Replacement graph for page 5 of Ex. T-500
4	Replacement graph for page 24 of Ex. T-500
5	Correction of Ex. 501, P. 1
6	Correction of Ex. 501, P. 2
7	Correction of Ex. 501, P. 4
8	Correction of Ex. 501, P. 6
9-14	Correction of Ex. 501, P. 7-12

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 513
ADMIT ☑ W/D ☐ REJECT ☐

Docket UE-991255 et. al.
Exhibit 513
Page 2
Correction to Graph on T-500, P. 3



Docket UE-991255 et. al.
Exhibit 513
Page 3
Correction to Graph on T-500, P. 5

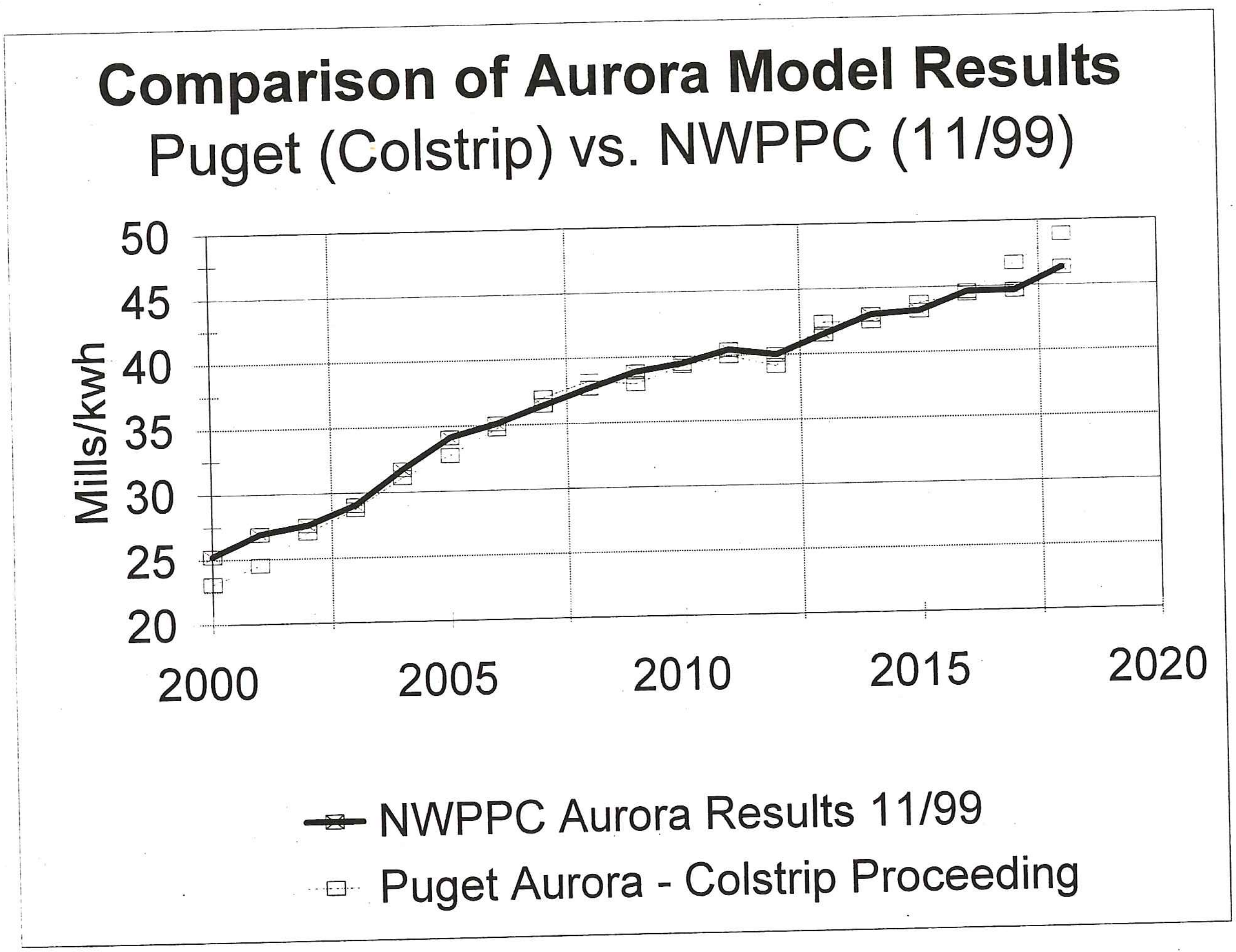


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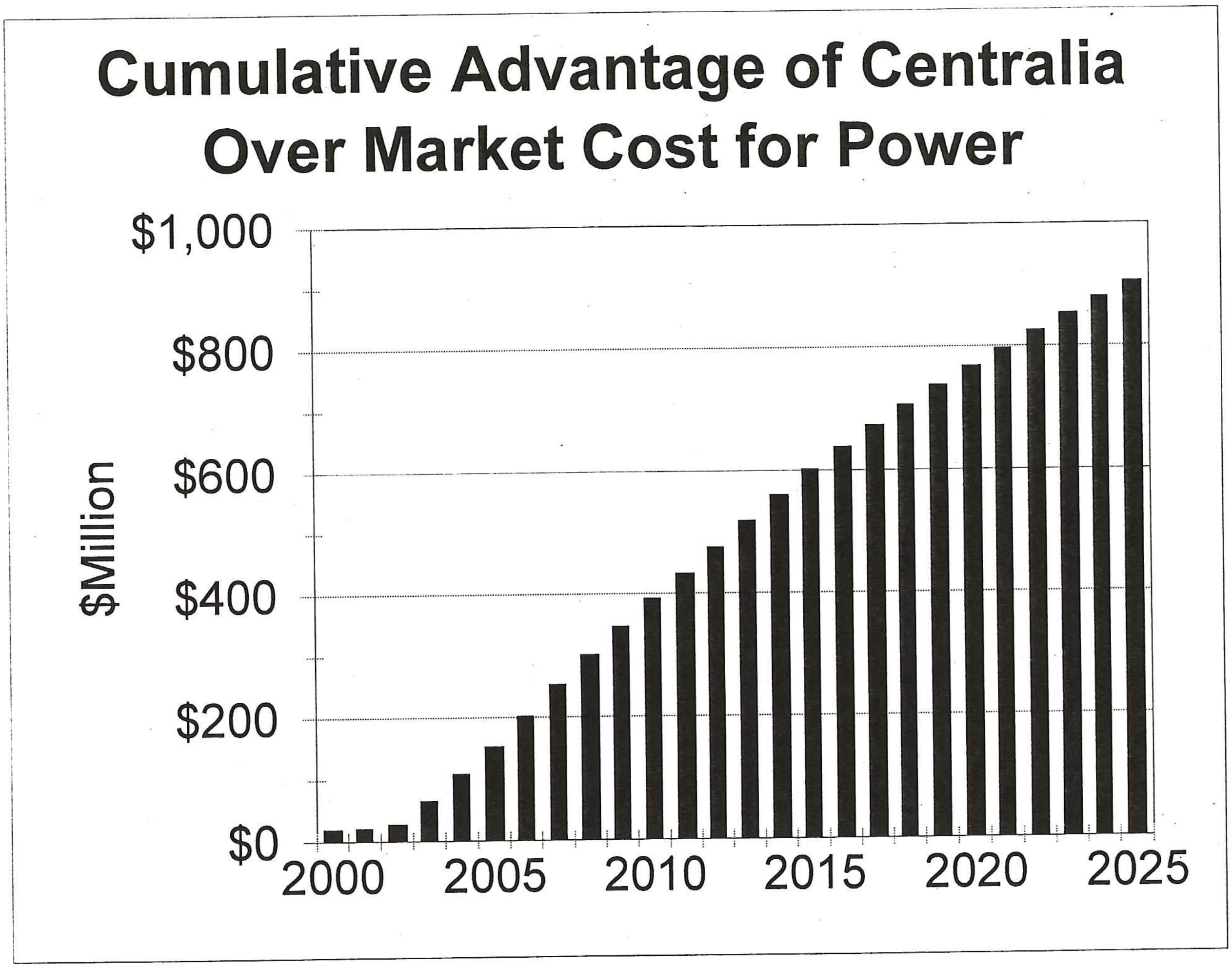
Exhibit 513
Page 4
Correction to Graph on T-500, P. 24



Summary of Results
Centralia Cost and Value of Power
2000-2025

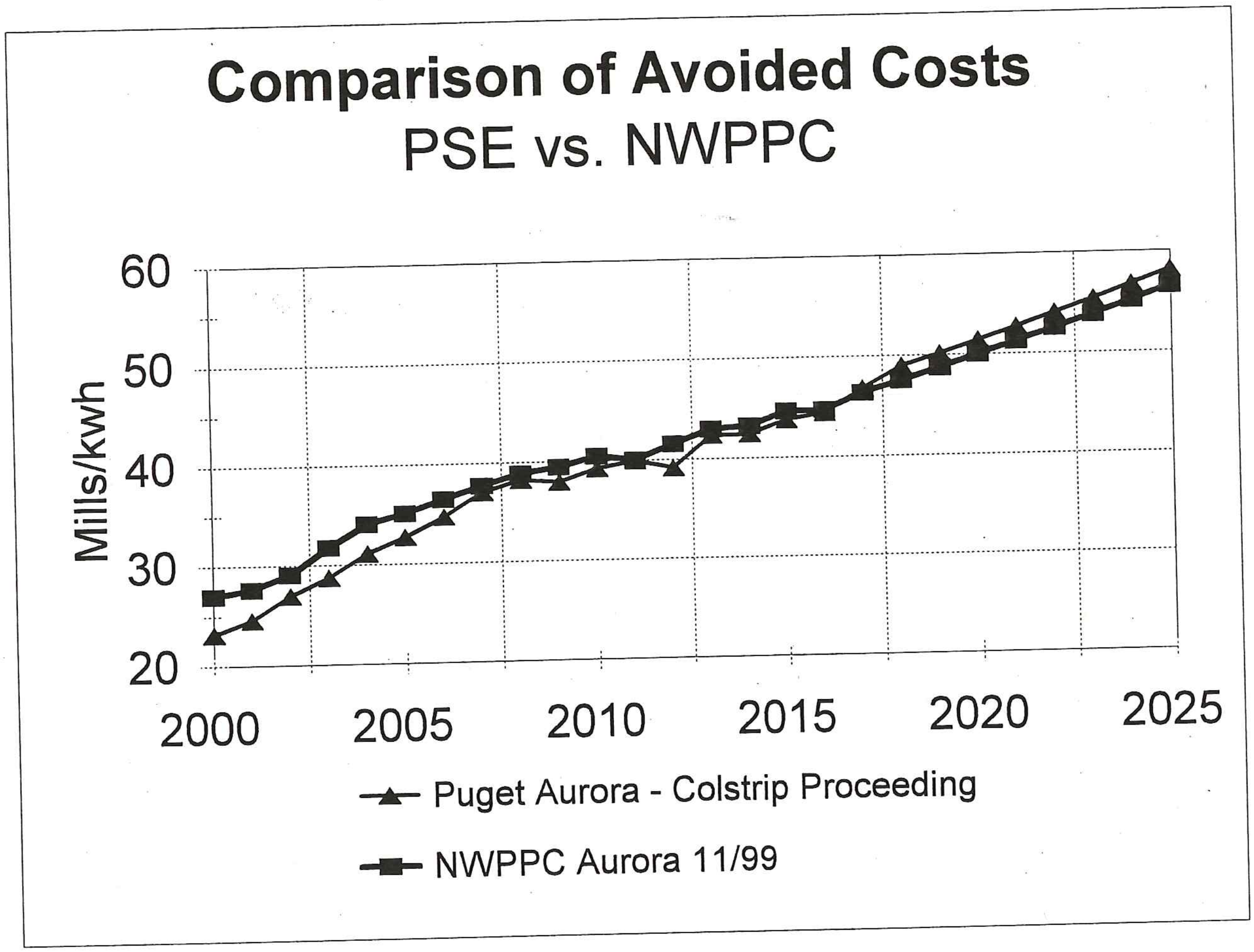
Scenario		Cost of Power	Value of Power	Years Analyzed	Minimum Required Sell Price	Sale Price to TransAlta	Gain on Sale to Make R/P Whole	Total Gain On Sale to TransAlta
1	Base Analysis	Pacificorp	NWPPC (11/99)	26	$1,129	$540	$906	$317
	Sensitivity Analyses							
2	24 Year	Pacificorp	NWPPC (11/99)	24	$1,077	$540	$854	$317
3	PSE / Aurora	PSE	NWPPC (11/99)	26	$1,127	$540	$904	$317
4	Aggressive Cost Containment	Pacificorp	NWPPC (11/99)	26	$1,264	$540	$1,041	$317
5	Pacific RAMPP-5	Pacificorp	RAMPP-5	26	$656	$540	$433	$317
6	Colstrip Equivalent	PSE	WUTC-Colstrip	26	$1,009	$540	$786	$317
7	PSE 26	PSE	PSE	26	$622	$540	$399	$317
8	Avista 26	Avista	Avista (new)	26	$744	$540	$521	$317
9	CO2 Tax	Pacificorp	NWPPC (11/99)	26	$724	$540	$501	$317

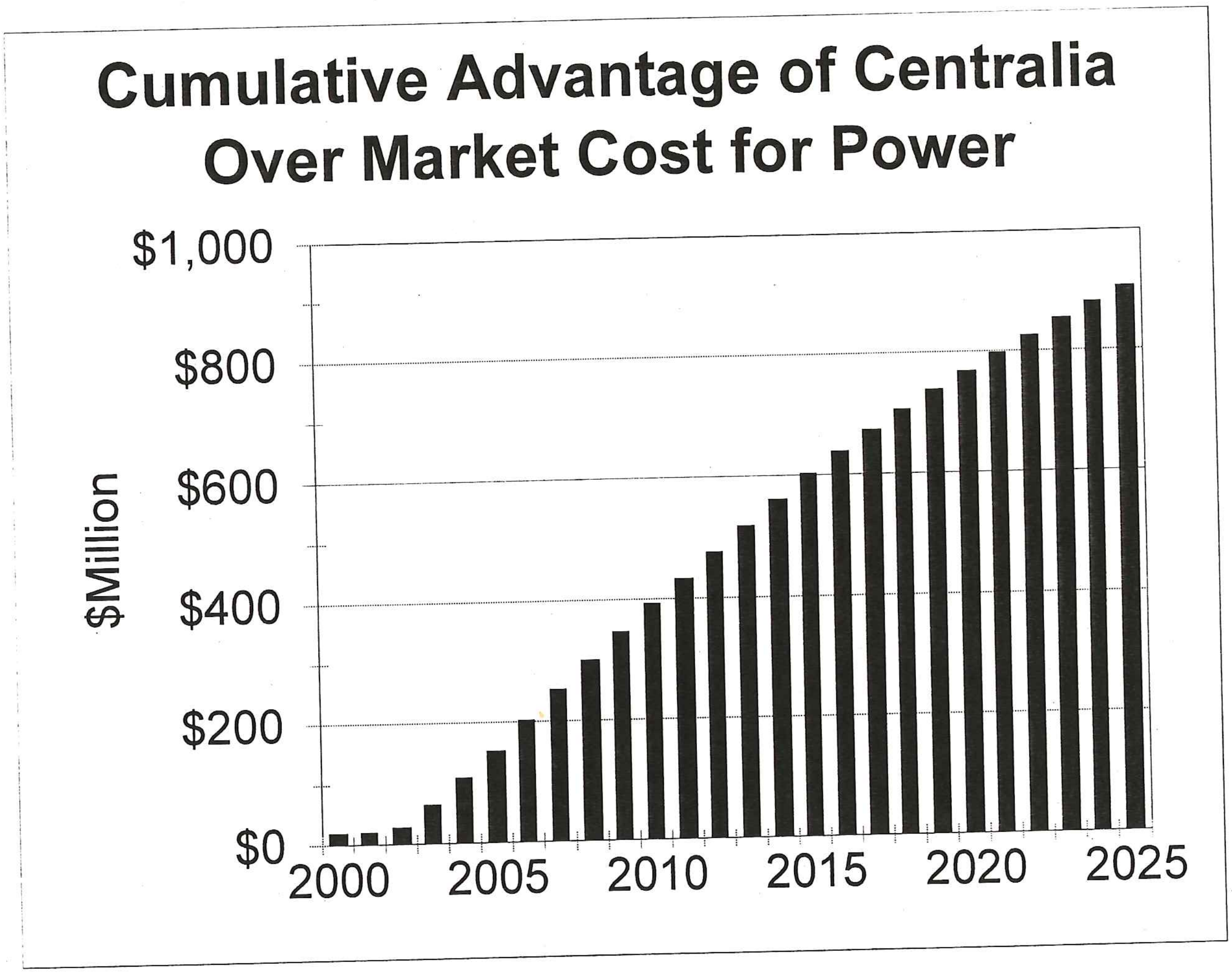
Note: All scenarios include dispatchability and capacity adders if not included in underlying forecasts

Comparison of Avoided Cost Estimates

Forecast:	RAMPP-4 PP&L	RAMPP-5 PP&L	Aurora Colstrip PSE	Centralia PSE	Centralia Avista	11/99 Avista	NWPPC 1998 Plan	NWPPC 11/99	Used In Scrubber Negotiation
Vintage:	1997	1999	1999	1999	1999	1999	1998	1999	1996
Year									
1999	14.6	16.2			22.5	21.9	25.3	25.3	13.6
2000	14.7	22.9	23.1	27.6	22.8	26.5	27.0	26.9	13.9
2001	15.1	23.8	24.6	27.4	23.8	27.0	28.1	27.6	14.3
2002	15.7	24.7	27.0	27.9	24.3	27.3	29.8	29.0	14.8
2003	16.3	25.9	28.8	28.3	25.0	27.5	30.6	31.7	15.4
2004	17.6	26.9	31.1	28.8	25.6	27.8	31.9	34.1	16.3
2005	18.1	27.8	32.8	31.1	26.2	28.0	32.7	35.1	16.8
2006	20.7	28.9	34.7	33.1	26.9	28.3	34.1	36.4	18.4
2007	21.0	30.0	37.1	35.0	27.5	30.3	35.1	37.7	18.8
2008	23.7	32.0	38.3	36.3	28.2	32.3	36.2	38.9	20.5
2009	27.9	33.1	38.0	36.0	28.9	34.3	38.6	39.4	22.9
2010	37.1	34.2	39.3	37.3	29.7	36.3	39.0	40.5	27.8
2011	38.4	35.3	40.0	38.0	30.4	*37.2*	40.4	40.0	28.8
2012	39.7	36.5	39.2	36.8	31.2	*38.1*	42.2	41.5	29.8
2013	41.1	37.6	42.4	40.2	31.9	*39.1*	43.4	43.0	30.8
2014	42.5	38.9	42.5	40.2	32.7	*40.1*	45.4	43.2	31.9
2015	43.9	40.2	43.8	41.6	33.6	*41.1*	46.1	44.6	33.0
2016	45.5	41.5	44.4	42.3	34.4	*42.1*	48.6	44.6	34.2
2017	47.0	42.9	46.8	44.2	35.3	*43.1*	*49.8*	46.4	35.4
2018	48.7	44.4	48.9	46.5	36.1	*44.2*	*51.1*	*47.5*	36.7
2019	50.4	45.9	*50.2*	*47.6*	37.0	*45.3*	*52.3*	*48.7*	38.0
2020	52.1	47.4	*51.4*	*48.8*	38.0	*46.5*	*53.6*	*49.9*	39.3
2021	53.9	49.1	*52.7*	*50.0*	*38.9*	*47.6*	*55.0*	*51.2*	40.7
2022	55.8	50.7	*54.0*	*51.3*	*39.9*	*48.8*	*56.4*	*52.5*	42.1
2023	57.8	52.4	*55.4*	*52.6*	*40.9*	*50.0*	*57.8*	*53.8*	43.6
2024	59.8	54.2	*56.8*	*53.9*	*41.9*	*51.3*	*59.2*	*55.1*	45.2
2025	61.9	56.0	*58.2*	*55.2*	*43.0*	*52.6*	*60.7*	*56.5*	46.8

Note: All Figures in italics are extrapolated at 2.5% assumed inflation
All estimates for "flat" power without ancillary service or locational adders


Comparison of Avoided Costs
PSE vs. NWPPC
Mills/kwh
60
50
40
30
20
2000
2005
2010
2015
2020
2025
Puget Aurora - Colstrip Proceeding
NWPPC Aurora 11/99


Cumulative Advantage of Centralia Over Market Cost for Power
$Million
$1,000
$800
$600
$400
$200
$0
2000
2005
2010
2015
2020
2025

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Page 9
Correction to Ex. 501, P. 7

BASE ANALYSIS

NWPPC Aurora Value of Power Revised 12/29/99	Source	2000	2001	2002	2003
Non-fuel Revenue Requirement	PP&L	$34,328	$44,764	$49,658	$45,177
Unit 1 Fuel	PP&L	$33,114	$33,651	$33,973	$34,734
Unit 2 Fuel	PP&L	$32,939	$33,604	$34,565	$35,549
Total		$100,380	$112,019	$118,196	$115,460
PP&L Share of Output	PP&L	3,873,072	3,877,197	3,867,687	3,893,872
Ownership / Operating cost mills/kwh	PP&L	25.92	28.89	30.56	29.65
Aurora Forecast from NWPPC	11/29	26.92	27.59	29.05	31.74
Extrapolation Beyond Forecast @ 2.5%					
Value of Power Before Shaping:		26.92	27.59	29.05	31.74
Add Dispatch @ 1.71 proportioned		1.71	1.75	1.84	2.02
Value with Dispatch Benefit	Avista	28.63	29.34	30.89	33.76
Add 1.00 mills capacity benefit	Avista	29.63	30.34	31.89	34.76
Output mwh @ 100% of Plant	PP&L	8,153,836	8,162,520	8,142,498	8,197,625
Cost of Power ($Millions)	3252.515	$211.33	$235.83	$248.83	$243.07
Value of Power ($Millions)	4115.13	$241.62	$247.66	$259.69	$284.91
Cost/Value of Sulphur Credits	-42.749	$9.78	$10.10	$1.99	($6.61)
Net Value of Plant vs. Market:	819.8651	$20.51	$1.73	$8.86	$48.44
	905.3631				
Present Value @	0.0716	$19.14	$1.51	$7.20	$36.74
Cumulative Present Value:		$19	$21	$28	$65

		24 Years	26 Years
Gain on Sale Required for Breakeven:		$853.27	$905.37
Book Value, Plant:	Avista	$116.51	$116.51
Book Value, Mine:	PP&L	$107.20	$107.20
Total Sale Price Required:		**$1,076.99**	**$1,129.08**
Actual Sale Price:	PP&L	$554.00	$554.00
Minimum % Gain On Sale To Ratepayers		**258.34%**	**274.12%**

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Correction to Ex. 501, P. 8

NWPPC Aurora Value of Power Revised 12/29/99	2004	2005	2006	2007	2008
Non-fuel Revenue Requirement	$47,159	$46,646	$46,435	$46,180	$49,845
Unit 1 Fuel	$35,273	$36,059	$38,322	$39,114	$40,280
Unit 2 Fuel	$35,143	$36,551	$38,331	$39,010	$40,971
Total	$117,575	$119,257	$123,088	$124,304	$131,096
PP&L Share of Output	3,870,048	3,845,230	3,977,927	3,962,682	4,016,576
Ownership / Operating cost mills/kwh	30.38	31.01	30.94	31.37	32.64
Aurora Forecast from NWPPC	34.10	35.11	36.44	37.69	38.90
Extrapolation Beyond Forecast @ 2.5%					
Value of Power Before Shaping:	34.10	35.11	36.44	37.69	38.90
Add Dispatch @ 1.71 proportioned	2.17	2.23	2.31	2.39	2.47
Value with Dispatch Benefit	36.27	37.34	38.76	40.08	41.38
Add 1.00 mills capacity benefit	37.27	38.34	39.76	41.08	42.38
Output mwh @ 100% of Plant	8,147,469	8,095,221	8,374,583	8,342,488	8,455,950
Cost of Power ($Millions)	$247.53	$251.07	$259.13	$261.69	$275.99
Value of Power ($Millions)	$303.64	$310.33	$332.95	$342.70	$358.32
Cost/Value of Sulphur Credits	($6.82)	($7.03)	($6.96)	($6.97)	($6.94)
Net Value of Plant vs. Market:	$62.93	$66.30	$80.78	$87.98	$89.28
Present Value @	$44.53	$43.78	$49.78	$50.60	$47.91
Cumulative Present Value:	$109	$153	$203	$253	$301

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepaye

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Correction to Ex. 501, P. 9

NWPPC Aurora Value of Power Revised 12/29/99	2009	2010	2011	2012	2013
Non-fuel Revenue Requirement	$49,860	$49,954	$50,084	$50,289	$50,524
Unit 1 Fuel	$41,380	$42,684	$44,373	$46,681	$47,999
Unit 2 Fuel	$41,805	$43,503	$45,034	$46,545	$47,562
Total	$133,045	$136,140	$139,491	$143,516	$146,085
PP&L Share of Output	4,026,506	4,077,035	4,131,729	4,204,368	4,216,136
Ownership / Operating cost mills/kwh	33.04	33.39	33.76	34.13	34.65
Aurora Forecast from NWPPC	39.45	40.46	40.03	41.51	42.96
Extrapolation Beyond Forecast @ 2.5%					
Value of Power Before Shaping:	39.45	40.46	40.03	41.51	42.96
Add Dispatch @ 1.71 proportioned	2.51	2.57	2.54	2.64	2.73
Value with Dispatch Benefit	41.95	43.03	42.57	44.15	45.69
Add 1.00 mills capacity benefit	42.95	44.03	43.57	45.15	46.69
Output mwh @ 100% of Plant	8,476,854	8,583,231	8,698,377	8,851,300	8,876,077
Cost of Power ($Millions)	$280.09	$286.61	$293.67	$302.14	$307.55
Value of Power ($Millions)	$364.12	$377.88	$379.00	$399.61	$414.44
Cost/Value of Sulphur Credits	($6.94)	($6.91)	($6.94)	($6.91)	($6.90)
Net Value of Plant vs. Market:	$90.96	$98.19	$92.28	$104.37	$113.79
Present Value @	$45.56	$45.89	$40.25	$42.48	$43.22
Cumulative Present Value:	$347	$393	$433	$475	$519

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepaye

NWPPC Aurora Value of Power Revised 12/29/99	2014	2015	2016	2017	2018
Non-fuel Revenue Requirement	$46,504	$47,201	$47,996	$48,854	$49,854
Unit 1 Fuel	$49,231	$50,587	$52,241	$53,914	$55,720
Unit 2 Fuel	$48,785	$50,115	$51,780	$53,184	$54,958
Total	$144,521	$147,903	$152,016	$155,952	$160,532
PP&L Share of Output	4,216,437	4,216,856	4,216,546	4,229,946	4,234,950
Ownership / Operating cost mills/kwh	34.28	35.07	36.05	36.87	37.91
Aurora Forecast from NWPPC	43.21	44.62	44.65	46.38	*50.1*
Extrapolation Beyond Forecast @ 2.5%				45.76	46.91
Value of Power Before Shaping:	43.21	44.62	44.65	45.76	46.91
Add Dispatch @ 1.71 proportioned	2.74	2.83	2.84	2.91	2.98
Value with Dispatch Benefit	45.95	47.46	47.48	48.67	49.89
Add 1.00 mills capacity benefit	46.95	48.46	48.48	49.67	50.89
Output mwh @ 100% of Plant	8,876,710	8,877,591	8,876,939	8,905,149	8,915,685
Cost of Power ($Millions)	$304.25	$311.37	$320.03	$328.32	$337.96
Value of Power ($Millions)	$416.77	$430.19	$430.38	$442.32	$453.69
Cost/Value of Sulphur Credits	($6.90)	($6.90)	($6.90)	($6.89)	($6.89)
Net Value of Plant vs. Market:	$119.42	$125.72	$117.24	$120.89	$122.61
Present Value @	$42.32	$41.58	$36.19	$34.82	$32.95
Cumulative Present Value:	$561	$602	$639	$673	$706

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepaye

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Correction to Ex. 501, P. 11

NWPPC Aurora Value of Power Revised 12/29/99	2019	2020	2021	2022	2023
Non-fuel Revenue Requirement	$51,028	$52,013	$52,367	$52,034	$52,607
Unit 1 Fuel	$57,113	$58,541	$60,005	$61,505	$63,042
Unit 2 Fuel	$56,332	$57,740	$59,184	$60,664	$62,180
Total	$164,474	$168,295	$171,556	$174,203	$177,830
PP&L Share of Output	4,234,950	4,234,950	4,234,950	4,234,950	4,234,950
Ownership / Operating cost mills/kwh	38.84	39.74	40.51	41.13	41.99
Aurora Forecast from NWPPC	*51.3*	*52.6*	*53.9*	*55.3*	*56.7*
Extrapolation Beyond Forecast @ 2.5%	48.08	49.28	50.51	51.78	53.07
Value of Power Before Shaping:	48.08	49.28	50.51	51.78	53.07
Add Dispatch @ 1.71 proportioned	3.05	3.13	3.21	3.29	3.37
Value with Dispatch Benefit	51.13	52.41	53.72	55.07	56.44
Add 1.00 mills capacity benefit	52.13	53.41	54.72	56.07	57.44
Output mwh @ 100% of Plant	8,915,685	8,915,685	8,915,685	8,915,685	8,915,685
Cost of Power ($Millions)	$346.26	$354.30	$361.17	$366.74	$374.38
Value of Power ($Millions)	$464.81	$476.20	$487.89	$499.86	$512.13
Cost/Value of Sulphur Credits	($6.89)	($6.89)	($6.89)	($6.89)	($6.89)
Net Value of Plant vs. Market:	$125.43	$128.79	$133.60	$140.01	$144.64
Present Value @	$31.46	$30.14	$29.18	$28.54	$27.51
Cumulative Present Value:	$738	$768	$797	$826	$853

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepaye

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Correction to Ex. 501, P. 12

NWPPC Aurora Value of Power Revised 12/29/99	2024	2025
Non-fuel Revenue Requirement	$53,923	$55,271
Unit 1 Fuel	$64,619	$66,234
Unit 2 Fuel	$63,735	$65,328
Total	$182,276	$186,833
PP&L Share of Output	4,234,950	4,234,950
Ownership / Operating cost mills/kwh	43.04	44.12
Aurora Forecast from NWPPC	*58.1*	*59.5*
Extrapolation Beyond Forecast @ 2.5%	54.40	55.76
Value of Power Before Shaping:	54.40	55.76
Add Dispatch @ 1.71 proportioned	3.46	3.54
Value with Dispatch Benefit	57.85	59.30
Add 1.00 mills capacity benefit	58.85	60.30
Output mwh @ 100% of Plant	8,915,685	8,915,685
Cost of Power ($Millions)	$382	$390
Value of Power ($Millions)	$524.71	$537.61
Cost/Value of Sulphur Credits	($7)	($7)
Net Value of Plant vs. Market:	$149.43	$154.37
Present Value @	$27	$26
Cumulative Present Value:	$880	$905

Gain on Sale Required for Breakeven:
Book Value, Plant:
Book Value, Mine:
Total Sale Price Required:
Actual Sale Price:

Minimum % Gain On Sale To Ratepaye

Exhibit 513 is responsive to the direction given by the Hearing Examiner at page 770 of the transcript.

Pages 2-4 replace the graphs which appear at page 3, 5, and 24 of Mr. Lazar's testimony, Exhibit T-500. The remaining pages correct pages 1, 2, 4, and 7-12 of Exhibit 501.

Two corrections to the analysis of Mr. Lazar, identified in the record, are reflected in Exhibit 513.

First, at Tr. 697, Mr. Lazar accepted that the value of power he represented as being Puget's estimates from the "Colstrip" proceeding were shifted by one year. Mr. Lazar has checked this, and Mr. Harris was correct. This data appears in the column marked "Aurora Colstrip PSE" on page 2 of Exhibit 501, and was also used to calculated Scenario 6 on page 1 of Exhibit 501. The magnitude of this correction is to increase the present value of the plant and minimum required sale price by approximately $170 million over the life of the plant.

Second, at Tr. 749, Mr. Lazar accepted (and checked on the stand) that he had omitted the 1 mill capacity adder in computing the value of power in his Exhibit 501, Pages 7-12. This error persisted in several of the scenarios, carrying forward to Page 1 of Exhibit 501, where the results are summarized. Page 5 of Exhibit 513, in the same format as Page 1 of Exhibit 501, has corrected for this error in each of the scenarios in which it occurred, which is all except Scenarios 6 and 8. The magnitude of this correction is to increase the present value of the plant and minimum required sale price by approximately $100 million over the life of the plant, but this amount varies slightly with each scenario.

Pages 7 and 8 of Exhibit 513 are corrections of pages 4 and 6 of Exhibit 501, reflecting the corrections noted above. Pages 9-14 of Exhibit 513 correct pages 7-12 of Exhibit 501 for Mr. Lazar's Base Analysis to reflect the error identified by the Hearing Examiner at Tr. 749.

Ex. 513 therefore consists of the following pages:

Page	Description
1	This page
2	Replacement graph for page 3 of Ex. T-500
3	Replacement graph for page 5 of Ex. T-500
4	Replacement graph for page 24 of Ex. T-500
5	Correction of Ex. 501, P. 1
6	Correction of Ex. 501, P. 2
7	Correction of Ex. 501, P. 4
8	Correction of Ex. 501, P. 6
9-14	Correction of Ex. 501, P. 7-12

Exhibit T-500, Errata Sheet 2, correcting the testimony of Mr. Lazar so that it is consistent with late filed Exhibit 513.

Corrections to the testimony of Jim Lazar as originally printed and distributed 12/8/99.

Page 2, line 10	*$1.1 billion* should read **<u>$900 million</u>**
Page 11, line 8	*$1.4 billion* should read **<u>$1.1 billion</u>**
Page 11, line 10	"*three*" should be "**<u>two</u>**"
Page 11, line 13	*$900 million - $1.3* billion should read **<u>$724 million - $1.26 billion</u>**
Page 12, Lines 1-11	*$1.4 billion* should read **<u>$1.1 billion</u>** *$1.3 billion* should read **<u>$1.0 billion</u>** *$914 million* should read **<u>$724 million</u>**
Page 15, line 26	*$1.4 billion* should read **<u>$1.1 billion</u>**
Page 16, line 3	*$651 million* should read **<u>$1.0 billion</u>**
Page16, line 3	"*20%*" should be "**<u>90%</u>**"
Page 17, line 12	*$1.497 billion* should read **<u>$1.129 billion</u>**
Page 17, line 15	*$653 million* should read **<u>$655 million</u>** **"or about 20% higher than the selling price to TransAlta."** should be restored
Page 21, line 22	*$1.4 billion to $900 million* should read **<u>$1.1 billion to $724 million</u>**
Page 25, line 4	*$1.5 billion* should read **<u>$1.3 billion</u>**
Page 27, line 22	*three* should read **<u>two</u>**