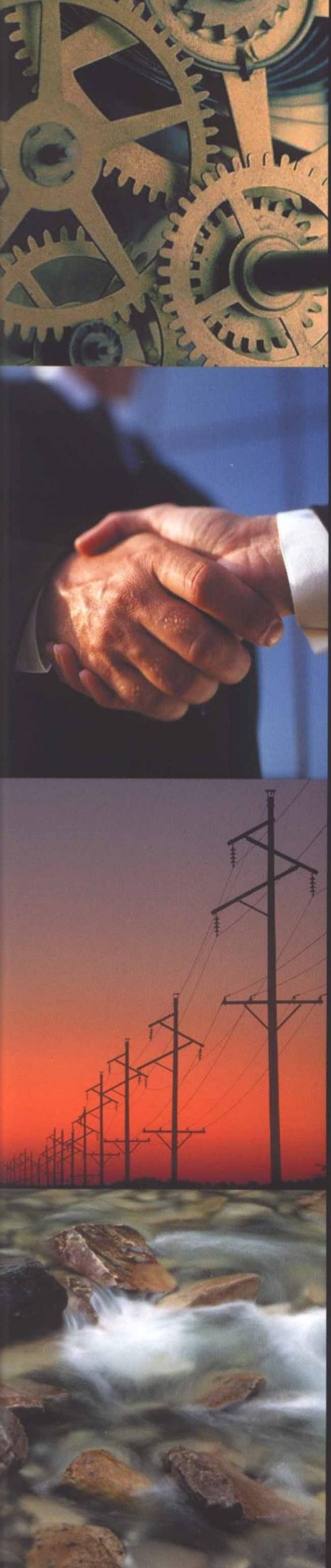


Rate Comparison: PSE and New Washington Public Power Utility

EES Consulting

Washington PUD Association

August 2008

Executive Summary

Given the proposed sale of Puget Sound Energy and the renewed interest in public power in Washington, the Washington Public Utility District Association contracted with EES Consulting, a Kirkland-based management consulting firm specializing in the energy and other natural-resource-based industries, to conduct an independent analysis of PSE's likely future rates compared to a new public utility with a projected load of 200 aMW and a service territory of 350,000 to 400,000 people.

The Washington PUD Association represents 27 public utility districts, including 22 of which provided electrical service to their communities. The voters in two other communities – Jefferson and Skagit counties – will decide this fall whether to authorize their public utility districts to become electric utilities, while voters on Whidbey Island will decide whether to create a new public utility district.

The data in this report is based on public information available regarding PSE costs and future capital plans, including PSE's integrated resource plan and filings with the Washington Utilities and Transportation Commission. In summary this study found:

- **PSE's Rates have gone up sharply since 2002.**

  On average, PSE costs have increased almost 4 percent per year since 2002, much faster than rates have increased for public power utilities and twice the national average.

- **PSE's rates are the highest in Washington, except for rates on Orcas Island.**

  Based on the most current rate schedules, average rates for residential customers in Washington range from 2.5 cents per kWh to just over 10 cents per kWh. PSE already has among the highest rates in Washington, and currently has a rate request before the UTC to increase overall rates another 9 percent.

- **PSE will need to invest $5 billion in infrastructure over the next five years, putting upward pressure on rates.**

  According to PSE, the company will need to invest $5 billion over the next 5 years for replacement and upgrade of existing infrastructure, for additional infrastructure to meet the demands of growth, for investment in new power contracts and resources, and for the additional cost of regulatory and legislative requirements. PSE also has a poor credit rating (Standard & Poor's BBB-Minus), making it more difficult and expensive for the utility to borrow money.

This added expense will put significant upward pressure on PSE's future rates. In addition, the increased exposure to the volatility in natural gas prices is likely to significantly impact future PSE retail rates.

- **PSE's future power supply cost risks are significantly higher than for public power utilities.**

  The coal-fired Colstrip Power Project in Eastern Montana is the company's single largest generating facility and faces significant added costs in a carbon-constrained environment, which other less coal dependent utilities don't face. In addition, PSE has announced plans to add significant amounts of natural gas to its resource mix, which increases risks with the volatility of natural gas prices. The company also must renew or sign new contracts with third-party power providers to meet demand. With a poor credit rating and potential foreign ownership, it is unclear whether PSE will be able to receive favorable terms in power supply transactions.

- **A new public utility would likely charge its customers much less than PSE would charge.**

  With access to low-cost power from the Bonneville Power Administration, a new public utility would be able to charge rates up to 20 percent less than the rates projected for PSE. For a hypothetical PUD using the full 200 aMW in lowest-cost power available from BPA, and serving a population base of 350,000 – 400,000 people, that would amount to a savings of up to $574 million in today's dollars over a 20 year period.

- **BPA has set aside low-cost power for new public power utilities that should be sufficient to serve a population of 350,000 to 400,000 people.**

  BPA has reserved 200 aMW of its lowest cost power for newly formed non-tribal public utilities. Based on PSE data for average residential usage, this would be sufficient to meet the needs of a service territory with a population of 350,000 to 400,000.

Introduction

EES Consulting, Inc. has been retained by the Washington PUD Association ("WPUDA") to assist in comparing the potential future rates of Puget Sound Energy, Inc. ("PSE") and a new PUD providing electric service to customers in Washington. Given the increased interest in public power in Washington and the proposed sale of PSE, the WPUDA determined that an independent analysis of PSE's future rates is appropriate. This analysis compares PSE's projected rates with a hypothetical public utility with a projected load of 200 aMW and a service territory encompassing approximately 350,000 to 400,000 people. The data in this report is based on public information available regarding PSE costs and future capital plans.

Background on PSE

PSE is a privately owned utility providing electrical power and natural gas service in the Puget Sound region of Washington State. It provides electrical power to more than 1 million customers in Island, Jefferson, King, Kitsap, Kittitas, Pierce, Skagit, Thurston, and Whatcom counties and natural gas to more than 720,000 customers in King, Kittitas, Lewis, Pierce, Snohomish and Thurston counties. The company owns fossil-fuel, hydroelectric, and wind-power plants with more than 2,400 MW of capacity.

Puget Sound Energy announced in late 2007 that it has entered into a sale and merger agreement with a foreign-based consortium of long-term infrastructure investors. According to PSE, the merger will bring $5 billion in capital over the next 5 years. This is needed for replacement and upgrade of PSE's current infrastructure, for additional infrastructure to meet growth in the service area, for investment in new power contracts and resources, and for the additional cost of regulatory and legislative requirements. In response, several public utility districts and Whidbey Island in Washington State are considering buying PSE electric facilities in their counties to retain local control and provide additional benefits to their communities.

Study Approach

The purpose of this report is to explore the potential future rates for PSE and compare those with Northwest Public Power alternatives. The first section of this report will provide a general overview of PSE's electric rates. PSE's power supply and wires rates are calculated separately in the next two sections. Finally, we provide a comparison of projected PSE rates with Northwest public power alternatives.

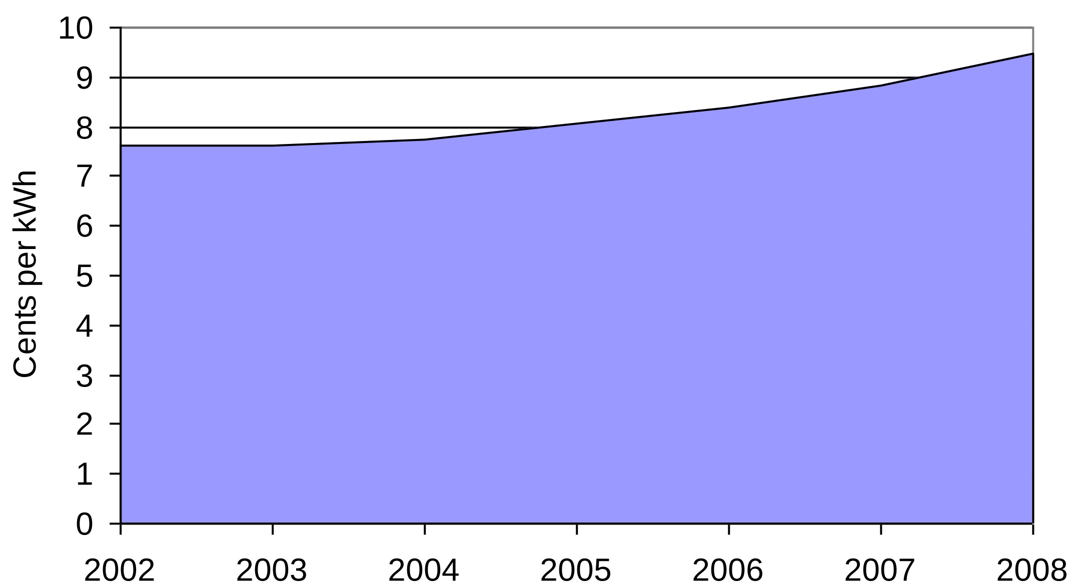
Comparison of PSE & Public Rates

History of Rates

When determining future rates, it is useful to examine the recent rate trends experienced by the utility's customers. Historically, PSE's rates were just above 7.5 cents per kWh for the residential class. However, as the chart below demonstrates, PSE costs have increased sharply, growing on average almost 4 percent per year since 2002.

For comparison, the US Energy Information Agency reports that the national average residential electricity cost grew only 2 percent per year from 1995 through 2006. The Bonneville Power Administration's priority firm rate for its customers grew on average 2.4 percent per year from 2002.

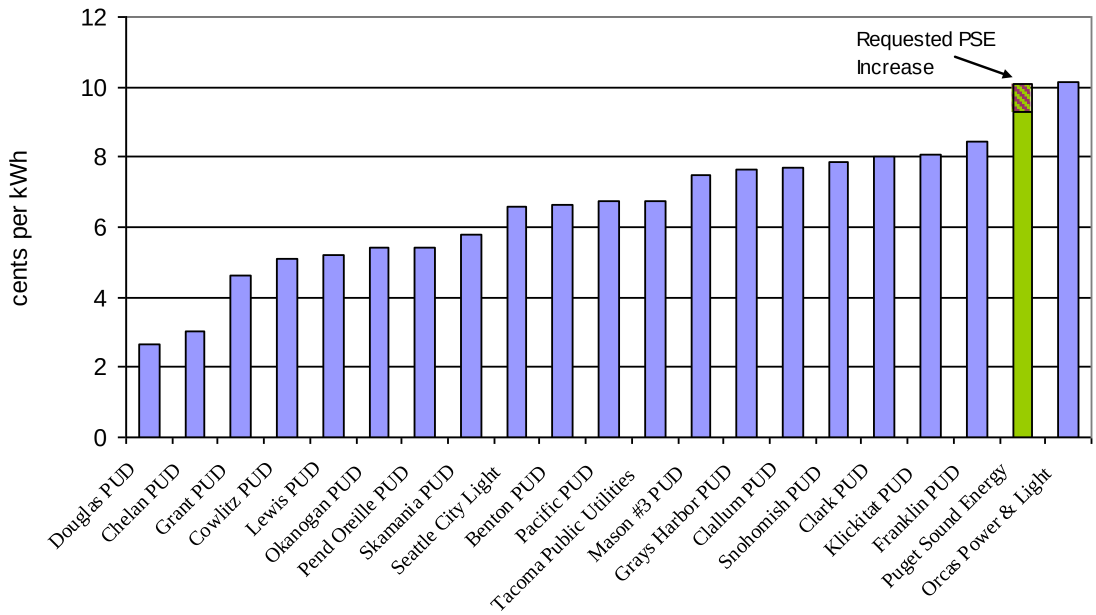
Table 1
PSE Residential Electricity Cost



Source: http://www.pse.com/insidePSE/ratereginformation/Pages/RatesElecTariffsRules.aspx

The Washington has generally enjoyed lower power costs than other areas of the nation due to access to the large hydro resources in the region. However, increased regulation and growth has recently put pressure on rates. Table 2 provides a rate comparison of current residential rates charged by Washington utilities.

Table 2
Residential Electricity Unit Costs
(2008 Data)



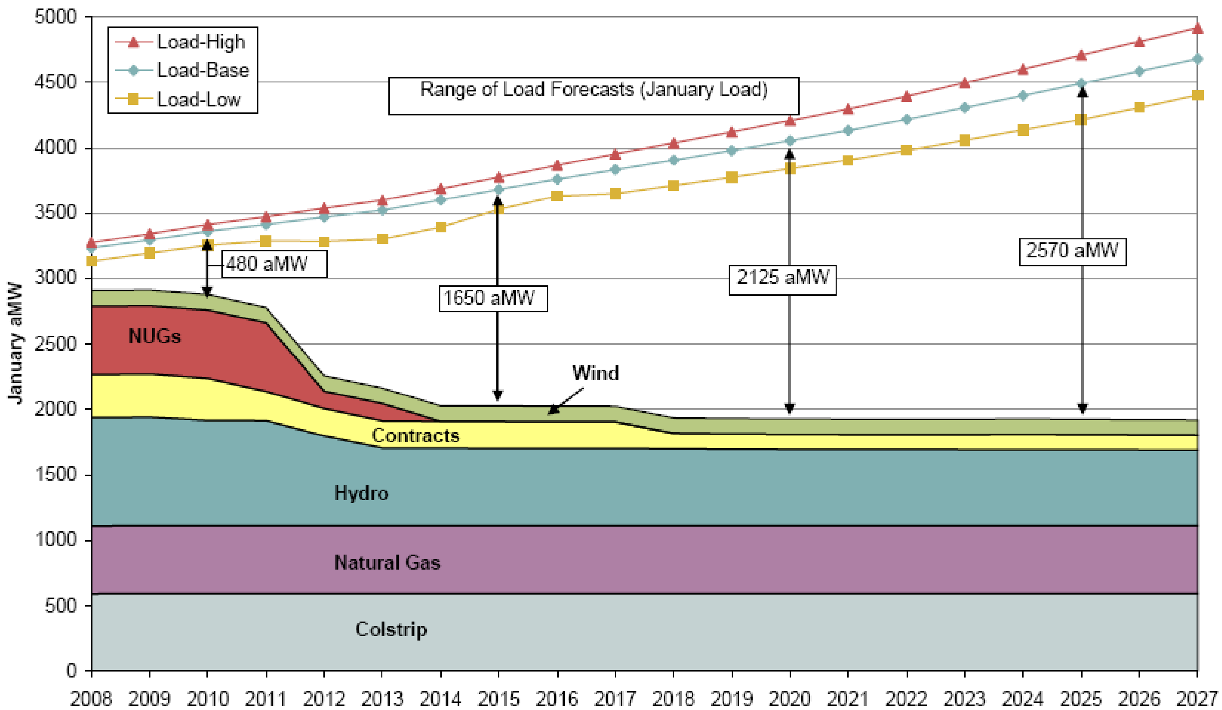
Based on the most current rate schedules, Washington electric rates for residential customers using an average of 1,000 kWh per month range from 2.5 cents per kWh to just over 10 cents per kWh. PSE rates, before the requested rate increase (below), are some of the highest in the Washington.

In December 2007, Puget Sound Energy filed a general rate case with the Washington Utilities and Transportation Commission (WUTC). This filing was updated in April 2008. PSE is requesting an overall increase in electric revenues of 9.8 percent and 11.99 percent for the residential class. This increase is, according to PSE, needed to recover investments made in 2006 and 2007 in infrastructure due to new customers, upgrades to the system and general cost increases. On July 3, 2008 PSE agreed to decrease the revenue increase requested to $165.2 million or a general rate increase of 8.99 percent. The filing did not specify how this reduction in the requested rate increase would translate into rate increases for the residential class. However, as Table 2 demonstrates, assuming that the residential rates will increase by the average increase of 9 percent, results in an average PSE residential rate above 10 cents per kWh.

Rate Pressures Due to Resource Planning Additions

PSE's current power supply portfolio is composed of natural gas-fired, hydroelectric, wind and coal (Colstrip) resources along with long-term contracts with independent power producers, other utilities and Non-Utility Generators (NUG). Table 3 below shows PSE's current resources versus projected 2008 through 2027 January loads.

Table 3
Projected 2008-27 January Loads versus Existing Resources



Source: PSE 2007 IRP

Table 3 shows that PSE will need to acquire nearly 700 aMW of new resources by 2011, 1,600 aMW by 2015 and 2,570 aMW by 2027. The recommended portfolio strategy in PSE's 2007 IRP calls for increases in demand-side resources via energy efficiency programs, wind and a small amount of biomass resource acquisition to meet renewable portfolio standards and natural-gas fired generation to meet PSE's remaining power supply requirements. It is important to note the exposure to natural gas price volatility in PSE proposed plan. The majority of new resources will consist of natural gas fired resources. Recent history has shown that the potential rate impact of relying on natural gas could be significant as demonstrated by PSE's continued requests for significant power cost rate increases as gas prices have been increasing in the last 5 years.

Rate Pressures Due to CIP Additions

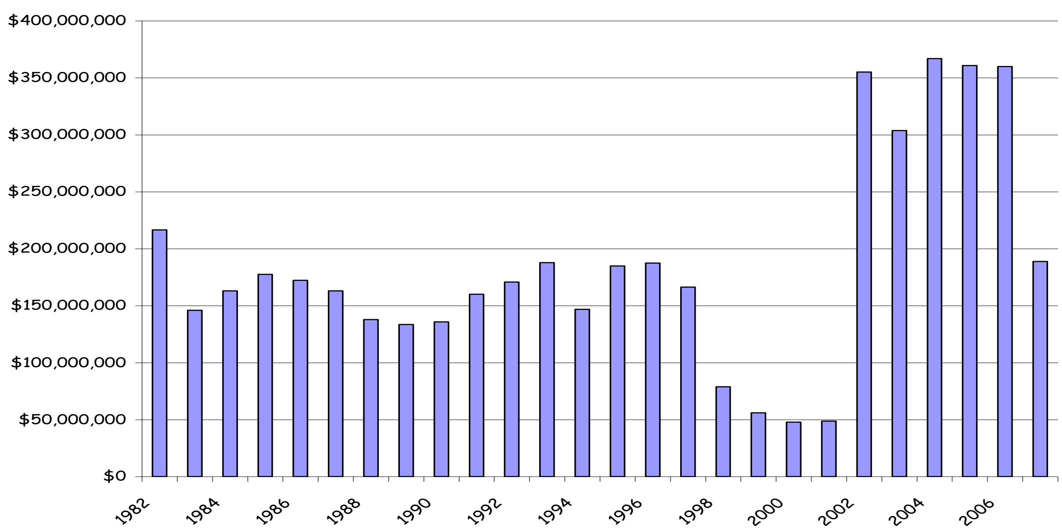
In December 2007, Puget Sound Energy filed a general rate case with the WUTC. According to the filing, the rate increase was in part due to significant increases in costs for transmission and distribution replacements and repairs. In addition, PSE's IRP states that PSE's electrical infrastructure is very old with some of the components operating since 1917. With loads projected to increase 2 percent annually, PSE faces significant challenges and capital costs to maintain and upgrade its system to reliably serve future loads. The 5-year infrastructure plan included in the 2007 IRP identifies 20 new substations, all with 25 MVA transformers, to be built in PSE's service territory between 2007 and 2011.

Residential Exchange Program

While PSE does not purchase power from the Bonneville Power Administration (BPA), PSE residential and irrigation customers receive benefits from the federal Columbia River hydroelectric system under the Northwest Power Act of 1980. Known as the Residential Exchange Program (REP), BPA payments to the private utilities in the Northwest were intended to mitigate for the disparity between residential costs for customers of higher-cost investor-owned utilities and public utilities, which received preference for low-cost power flowing from the Columbia River dams. These REP benefits are ultimately paid for by the customers of public power utilities that buy power from BPA, through higher BPA wholesale power rates.

The Residential Exchange credit was suspended in May 2007 after the Ninth Circuit Court of Appeals ruled that BPA failed to follow the law in determining level of benefits and had illegally shifted the cost of the program onto public utilities. It has since been reinstated at a lower level. One of the main issues remaining is the appropriate level of future benefits provided to the investor owned utilities. The REP had been in the range of $150 million or less annually in nominal dollars for all investor owned utilities in the Northwest through most of the years prior to the agreement between the IOUs and BPA that caused payments for the 2002-May 2007 period to balloon to more than $350 million.

Table 4
Historic Investor Owned Residential Exchange Benefits Paid



While not directly affecting PSE rates, the temporary loss of the Residential Exchange Credit in May 2007, as a result of the court decision, did significantly affect the amount PSE's residential customers paid for their electrical usage. In recent years, the REP had shielded PSE's residential customers from more than 20 percent of PSE's full power costs. When BPA suspended REP payments to investor-owned utilities, PSE passed those costs onto its residential customers, whose bills went up accordingly. While the program is expected to continue, future REP benefits are likely to be much lower than in recent years and will offset much less of PSE's future cost increases. While PSE will need to add a significant amount of new and expensive power resources, increasing its average system costs, REP is unlikely to increase in a similar manner, due to the court ruling and rate protections in the Northwest Power Act for BPA's public utility customers. In addition, PSE and the other investor-owned utilities may be required to return a portion of the excess REP payments for 2002-2007.

Forecast of PSE Rates

Power Supply

To compare power supply costs for PSE compared to a new public power utility purchasing a combination of BPA tiered rate products and/or the market-based power, we began with the average system costs (ASC) in the 2009 PSE ASC Report While these ASCs are not yet final, we believe they are the best benchmark currently available. The ASCs include the costs associated with generating and transmitting power to serve PSE's customers. In the 2009 PSE ASC Report, annual average system costs are provided in $/MWh for 2009 through 2013. ASCs were escalated by 2 percent annually beginning in 2013.

The costs associated with new resource additions were estimated using the new resources included in PSE's 2007 IRP preferred portfolio strategy. This resource plan includes adding new wind and natural gas resources. The natural gas resources included in the preferred strategy include both combined- and simple-cycle combustion turbines (CCCT and SCCT). The melded cost of PSE future resources was calculated by taking the weighted average of the ASC for existing resources and the cost for new resources.

Table 5
Forecast of PSE Existing and New Resource Costs ($/MWh)

Year	PSE Existing Resources	New Wind Resources	New CCCT Resources	New SCCT Resource	Melded PSE Power Supply
2010	58.4	96.3	77.6	94.1	59.6
2011	59.1	98.2	79.4	96.3	61.0
2012	59.7	100.1	81.2	98.6	65.6
2013	60.4	102.1	83.0	100.9	67.5
2014	61.6	104.2	84.9	103.3	69.3
2015	62.9	106.3	86.9	105.7	71.0
2016	64.1	108.4	88.9	108.2	72.8
2017	65.4	110.6	90.9	110.8	74.9
2018	66.7	112.8	93.0	113.5	77.4
2019	68.1	115.0	95.2	116.2	79.7
2020	69.4	117.3	97.4	119.0	82.0
2021	70.8	119.7	99.7	121.8	84.2
2022	72.2	122.1	102.0	124.8	86.6
2023	73.7	124.5	104.4	127.8	89.0
2024	75.1	127.0	106.9	130.9	91.4
2025	76.7	129.5	109.4	134.1	93.9
2026	78.2	132.1	112.0	137.3	96.4
2027	79.7	134.8	114.7	140.7	99.2
2028	81.3	137.9	117.4	144.1	102.0
2029	83.0	141.1	120.2	147.7	104.8

Based on PSE's July 2008 ASC filing, power supply costs are approximately 70 percent of total revenue requirements. Based on this assumption, the power cost increases would translate into retail rate increases of 13 percent in the first 5 years, 26 percent over the first 10 years, 40 percent over 15 years and 53 percent over the 20-year study period.

Wires

The comparison of distribution costs between PSE and public ownership is more straightforward than for the power supply costs. In general, local distribution rates for a new public power utility should not differ materially from the rates charged by PSE. Differences can occur based on individual circumstances, but a new public power utility would need to provide generally the same services and upgrades as would PSE. However, a new public power utility will benefit from a much lower cost of capital than PSE.

New Publics

In the 1970s, threats of insufficient resources to meet the region's electricity demands led to passage of the Northwest Power Act. In that Act, Congress, among other things, provided that BPA's public agency customers had a statutory right for service from BPA to meet their net requirements loads. Any new public utility is therefore likely to use BPA as a source for power supply. BPA is a significant market participant, both as a seller and buyer, and has access to all resources available on the West coast.

BPA Columbia River dams provide low-cost, reliable power to the Northwest region. However, due to growth in electricity consumption, power supply requests placed on BPA are projected to exceed the power generation from these dams. In order to address this issue, BPA has proposed offering low-cost Tier I power supply products based on its hydropower resources, and Tier 2 products based on market resources.

BPA Tier 1

Under BPA's proposal, Tier 1 power supply for new public power utilities (including new Tribal utilities) will be limited to 250 aMW in aggregate total during the term of the new 20-year HWM contracts, of which only 50 aMW will be added in any single rate period (every two years). While this limited access to low-cost BPA power has not been tested in court, this report assumes the limits will remain in place. Putting this limitation in perspective, BPA's 250 aMW reserve for newly formed public power utilities could serve all residential customers in a service territory with a population of 350,000 to 400,000.

BPA – Tier II

Tier 2 power would be available for a new public power utility to meet demand above any Tier 1 allocation. This power would be available at the time the public utility is established and without timing or quantity limits. The Tier 2 resource option will provide renewable or non-renewable power supply at a price that most likely will be very competitive to market purchases due to the size and experience of BPA. BPA generates and supplies between two and three times the power distributed by PSE.

Analytical Comparison

Based on the analysis of power cost for each entity, a hypothetical new public power utility serving a population of approximately 350,000 people could save ratepayers up to $574 million over 20 years in today's dollars. These savings would translate into retail rates up to 20 percent less than rates projected for PSE. Table 6 provides the comparison of costs for the two types of utilities.

Table 6
Comparison of Power Supply Costs

	Full HWM/Tier 1	50% of HWM/Tier 1	Status Quo =PSE Resource Cost
20-Year NPV of Power Costs (millions)	$1,461	$1,718	$2,035
Difference from Status Quo NPV (millions)	($574)	($317)	NA
Percent Difference	(28%)	(16%)	NA
Estimated Retail Rate Difference from Status Quo	(20%)	(11%)	

Additional Benefits

In addition to the benefit of cheaper BPA power, a public utility has additional benefits not available to PSE which are likely to reduce costs to rate payers. A significant component of a utility's overall costs is associated with meeting the costs of its capital expenditures. A new public utility has lower financing costs as compared to PSE options due to tax exempt financing. While PSE's average weighted cost of debt after tax is approximately 10 to 11 percent, public utilities are borrowing money today at rates between 4 and 5 percent. This difference is very significant and can translate directly into savings to the rate payers.

Additional savings can also materialize due to opportunity for increased efficiency through integrated utility operations. For example, many existing PUDs are already providing other utility services to their communities. These PUDs already have customer service and customer accounting infrastructure in place. The addition of electric service could improve local efficiency through sharing of personnel, equipment and supplies across utilities.

Finally, public power utilities are not for profit, while PSE customers pay a 10.4 percent (with a recent request for an increase to 10.8 percent pending at the WUTC) rate of return to PSE shareholders.

Technical Appendix

PSE Electricity Rates Overview

Current Rates

PSE's residential customers currently pay a fixed monthly customer charge in addition to energy charges based on monthly usage. For example, the average residential monthly charges (based on 1,000 kWh usage) is provided in Table A-1 below.

Table A-1
Average Residential Monthly Charges

	First 600 kWh (Cents per kWh)	Over 600 kWh (Cents per kWh)	Average Rate (1,000 kWh Usage) (Cents per kWh)
Customer Charge	$6.02 per month (Single Phase)		0.6020
Energy Charge	7.4314	9.2122	8.1437
Low Income Program	0.0322	0.0322	0.0322
Conservation	0.3137	0.3137	0.3137
Power Cost Adjustment	0.3245	0.3245	0.3245
Wind Power Credit	(0.1404)	(0.1404)	(0.1404)
Total	**7.9614**	**9.7422**	**9.2757**

This calculation results in an average rate of approximately 9.28 cents per kWh for a customer using 1,000 kWh per month.

Pending General Rate Increase Proposal

In December 2007, Puget Sound Energy filed a general rate case with the Washington Utilities and Transportation Commission (WUTC). This filing was updated in April 2008. PSE in this filing is requesting an overall increase in electric revenues of 9.8 percent or $179.9 million. This increase is, according to PSE, needed to recover investments made in 2006 and 2007 in energy infrastructure due to new customers, upgrades to the system and general cost increases.

According to the filings, the following categories are the main drivers for the increase:

- $55.1 million for power costs during the year;
- $10.7 million relating to new power plant additions;
- $8.5 million for transmission and distribution partially explained by increased tree trimming and storm damage expense;
- $19.9 million for storm damage relating to the December 2006 storm;
- $9.5 million for salaries, outside service, and insurance;

- $19.6 million for increased depreciation & amortization, and
- $38.0 million for increased rate base, of which $12.2 million results from an increase in the return earned by investors.

The average rate increase requested by PSE was 9.8 percent in the initial filing. This translated into a rate increase in the proposed rate for residential customers of approximately 11.99 percent. This would result in an average rate of 10.39 cents per kWh for an average usage of 1,000 kWh per month as compared to the current 9.28 cents per kWh.

On July 3, 2008 PSE agreed to decrease the revenue increase requested to $165.2 million or a general rate increase of 8.99 percent. The filing did not specify how this reduction in the requested rate increase would translate into rate increases for the residential class. The rate case is ongoing and it is not yet clear what the WUTC will allow as a final rate increase. Parties in the rate case have proposed revenue increases between $4.3 million and $107 million, much smaller than the currently requested $165 million.

Merger Potential Impacts on PSE Rates

As stated previously, Puget Sound Energy announced in late 2007 that it has entered into a sale and merger agreement with a foreign-based consortium of long-term infrastructure investors. Significant objections to the merger were filed by several parties.

According to testimony filed by the Public Council of Washington State …the most recent corporate credit rating for Puget by S&P is “BBB-“ and the Company is on “credit watch with negative implications”. Because PSE’s corporate credit rating is currently at the lowest “BBB” level, any downward movement would be to the non-investment grade level and this could cause significant increase in the cost of capital needed to operate.

Several parties to this case have filed a proposed joint settlement with the commission; however, this is not a final resolution of the case. The proposed settlement must be reviewed by the three commissioners, who can approve, reject or modify the settlement. If the commission makes major modifications, the signing parties have the option of withdrawing from the agreement.

The proposed settlement, in part, calls for additional equity to reduce the debt level at Puget Energy, the parent company of PSE. The proposal also calls for additional financial conditions to protect PSE ratepayers. PSE also agrees to specific conditions in support of programs for renewable energy, conservation and assistance to low-income customers. However, there is still concern by some parties that the merger is too risky for PSE’s ratepayers.

PSE Rate History

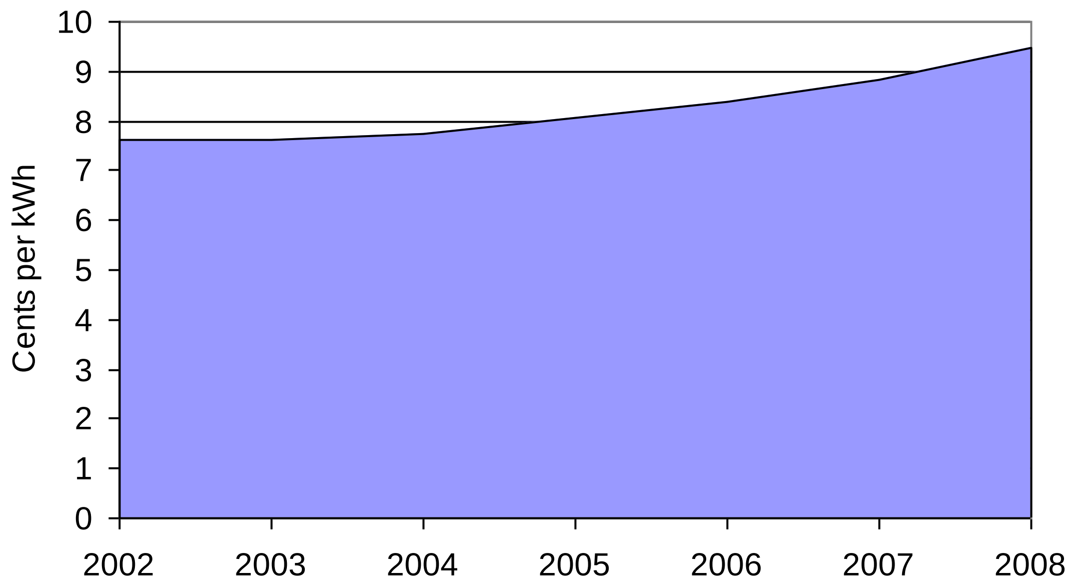
When determining future rates, it is useful to examine the recent rate trends experienced by the utility’s customers. In particular, the difference between the requested rate increases and the WUTC approved rate increase can provide useful information when projecting rates. Table A-2 provides the major rate changes approved by the WUTC in the past 5 years.

Table A-2 PSE General Rate Case History		
Date Requested	**Requested Revenue Increase**	**Approved Revenue Increase**
July 2008	$165.2 million / 8.99%	Pending
December 2007	$179.9 million / 9.7%	Pending
July 2006		$96 million / 7.1%*
February 2006	$148.8 million / 9.2%	-1.3%
April 2004	$ 81.4 million / 5.7%	$ 56.6 million /4.1%

**Note: Separate Power Cost Only Rate Case*

Historically, PSE's rates have been in the order of 7 to 8 cents per kWh for the residential class. However, as the chart below demonstrates, PSE costs have increased sharply, growing on average almost 4 percent per year since 2002. For comparison, the US Energy Information Agency reports that the national average residential electricity cost grew only 2 percent per year from 1995 through 2006. The Bonneville Power Administration's priority firm rate for its customers grew on 2.4 percent per year from 2002.

Table A-3
PSE Residential Electricity Cost



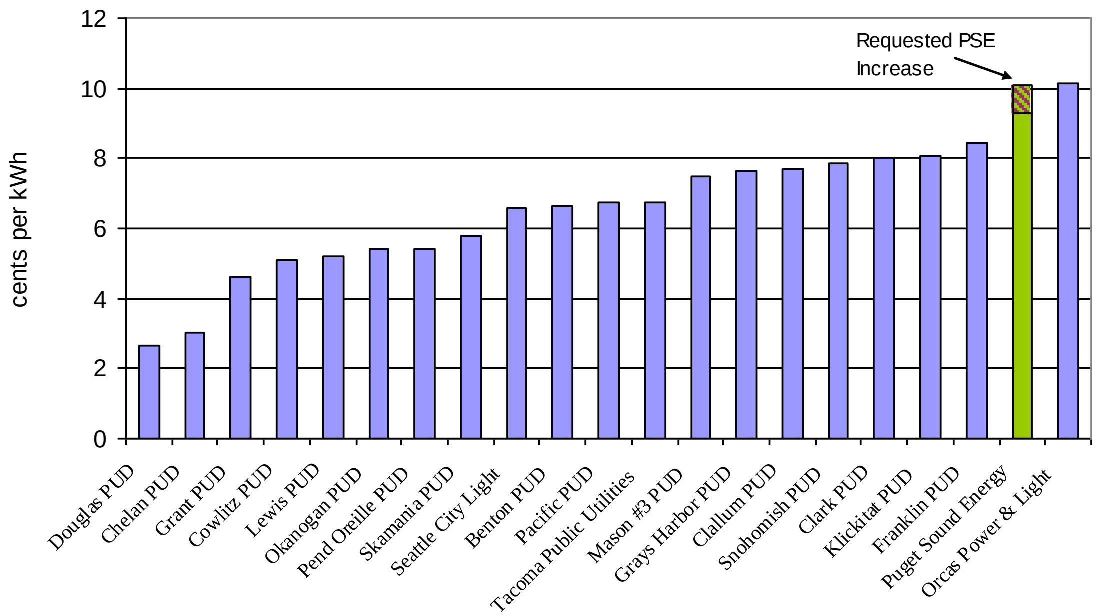
Source: http://www.pse.com/insidePSE/rateregoinformation/Pages/RatesElecTariffsRules.aspx

PSE Rate Comparisons

Washington has generally enjoyed lower power costs than other areas of the nation due to access to the large hydro resources in the region. However, increased regulation and growth has recently put pressure on rates in Washington.

Table A-4 provides a rate comparison of current residential rates charged by utilities in Washington.

Table A-4
Residential Electricity Unit Costs
(2008 Data)



Based on the most current rate schedules, average rates for residential customers in Washington using an average of 1,000 kWh per month range from 2.5 cents per kWh to just over 10 cents per kWh. PSE rates, before the recently requested rate increase of and average 9 percent, are some of the highest in the state.

Basics of Rate Setting

The first distinction often made in setting rates is the type of utility that is attempting to set the rates. Utilities are generally divided into two types by ownership—public and private utilities.

Public utilities are generally owned by a municipality, cooperative, county, or special district and are operated on a not-for-profit basis. Public utilities are generally capitalized by issuing debt and soliciting funds from customers through direct capital contributions or user rates. As nonprofit entities, public utilities do not pay federal income taxes. Finally, a public utility is usually regulated by a publicly-elected or appointed City Council, Board of Commissioners, or Board of Trustees.

In contrast, private electric utilities are capitalized by issuing debt or equity (stock) to the general public. The owners of the private utility are its equity contributors, or shareholders. Private utilities are taxable entities, and finally, they are generally regulated by state public utility commissions.

These differences in ownership and other characteristics often lead to two different methods for setting rates. By virtue of differences noted above for a public versus a private utility, their revenue requirements are based upon different elements or methodologies. Most private utilities use what is known as a "utility" or "accrual" basis of determining revenue requirement or setting rate levels. This convention calculates a utility's annual revenue requirement by aggregating a period's operation and maintenance (O&M) expenses, taxes, depreciation expense, and a "fair" return on investment. Operating expenses include the labor, materials, supplies, etc., that are needed to keep the utility functioning. Private utilities must also pay federal income taxes, along with any applicable property, franchise, sales or other forms of taxes. Next, depreciation expense is a means of recouping the cost of capital facilities over the useful lives of those facilities and also a means of generating internal cash. Finally, a return on the capital invested pays for the utility's interest expense on indebtedness, provides funds for a return to the utility's equity holders in the form of dividends, and leaves a balance for retained earnings and cash flow purposes.

In contrast to the "utility" or "accrual" method of developing revenue requirement for private utilities, public utilities follow a different method of determining annual revenue requirement. The convention used by most public utilities is called the "cash basis" of cost accounting. As the name implies, a public utility aggregates its cash expenditures to determine its total revenue requirement for a specified period of time. This methodology conforms nicely to most public utility budgetary processes, and is a very straightforward and easily understood calculation.

Under the "cash basis" approach, there are four component costs. They are operation and maintenance expenses, taxes, debt service, and capital improvements funded from rates. The operating portion of the revenue requirement, i.e., O&M and taxes, are similar under either methodology.

Table A-5 may be helpful in comparing the cash and utility accounting conventions for public and private utilities, respectively.

Table A-5
Cash vs. Utility Basis Comparison

	Cash Basis for Public Utility		Utility (Accrual) Basis for Private Utility
+	O&M Expense	+	O&M Expense
+	Taxes	+	Taxes
+	Capital Improvements Financed with Operating Revenues	+	Depreciation Expense
+	Debt Service	+	Return on Investment
Σ	= Revenue Requirement	Σ	= Revenue Requirement

Another difference between the two types of utilities is that a privately-owned utility, such as PSE, must get approval from the Washington Utility and Transportation Commission (WUTC) before changing rates. A publicly-owned utility is not regulated by the WUTC, but is regulated by a local city council, utility commission or utility board and rates must be approved before implementing by the local regulatory body. Both types of utilities have rate setting constraints by state statute.

Finally, financing of capital improvements differs significantly between the two types of utilities. Public utilities rely on cash available or tax-free financing. In addition, revenue bonds may be available for some large outlays. Private entities rely on taxable financing and equity provided by shareholders.

Rate Components

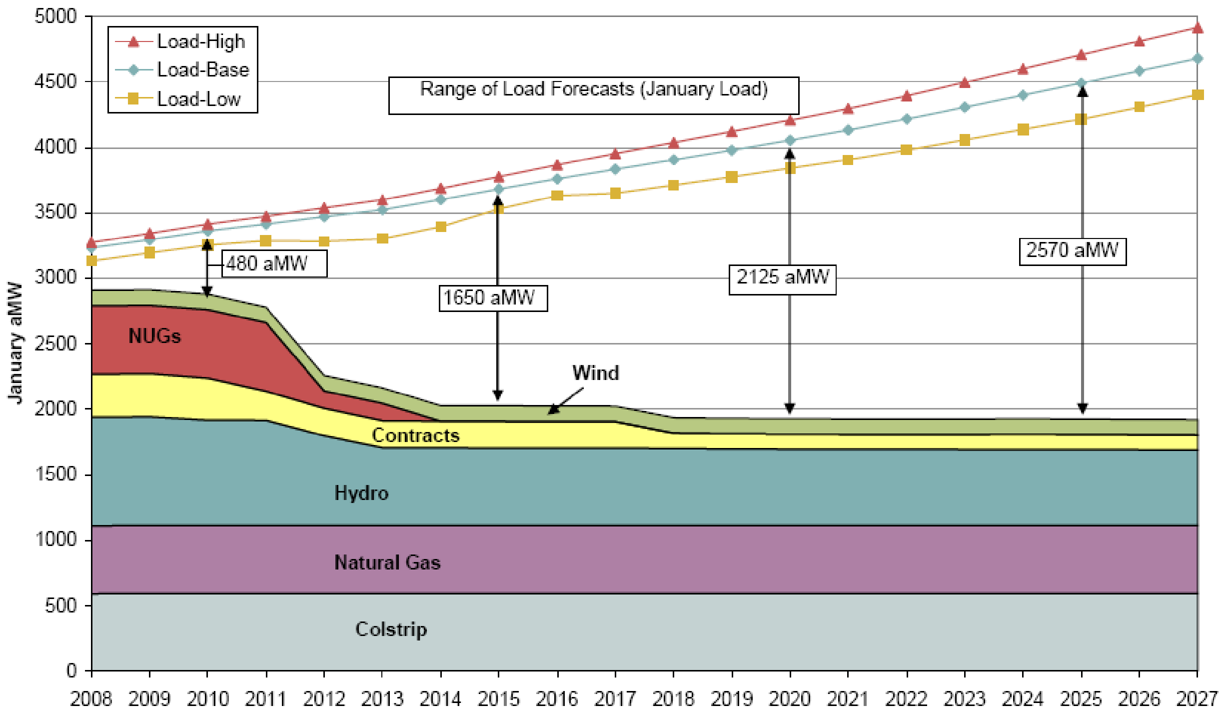
When setting rates, costs are generally separated into two different categories: power supply and wires. Power supply costs include all cost of bringing power to the utility's service area. This cost includes the actual cost of the power supply, energy and demand, any ancillary services needed to ensure reliability and shape the power to meet loads and the transmission of power from the power source to the service area. Power supply costs typically represent the larger portion of the total costs of operating an electric utility system and depend on the type of resource purchased and the price at the time of purchase. Wires expenses are those associated with traditional distribution facility construction, operations and maintenance, customer accounts, customer services, and administrative and general (A&G) expenses.

PSE Power Supply

PSE Current Power Supply Portfolio

PSE's current power supply portfolio is composed of natural gas-fired, hydroelectric, wind and coal (Colstrip) resources along with long-term contracts with independent power producers, other utilities and Non-Utility Generators (NUG). Table A-6 below shows PSE's current resources versus projected 2008 through 2027 January loads.

Table A-6
Projected 2008-27 January Loads versus Existing Resources



Source: PSE 2007 IRP

Table A-6 shows that PSE will need to acquire nearly 700 aMW of new resources by 2011, 1,600 aMW by 2015 and 2,570 aMW by 2027.

PSE Power Supply Challenges

2007 Integrated Resource Plan (IRP)

In the 2007 IRP PSE considered six scenarios when analyzing resource portfolio strategies. The six scenarios illustrate the challenges utilities currently face when making resource decisions. The six scenarios include:

1. Current Trends: Current economic, marketplace and regulatory trends continue in the future.
2. Green World: Costs associated with greenhouse gas emissions turn out to be greater than expected.
3. Low Growth: Economic growth in the region does not meet expectations.
4. Robust Growth: Economic growth in the region exceeds expectations.
5. Technology Improvements: Technological advances improve heat rates and capital costs associated with potential new resources.
6. Escalating Costs: Technological advances take place but are accompanied by higher costs than projected.

In considering 12 alternative resource portfolios PSE considered the impact of the scenarios outlined above on each resource portfolio's total costs. PSE also assessed the likelihood of each of the scenarios taking place. Due to regulatory and technological hurdles, portfolios that included coal projects without carbon capture and sequestration (CCS) were eliminated from contention as were portfolios that included Integrated Gasification Combined Cycle (IGCC).

Wind is currently the only renewable resource capable of producing power in the quantities required to meet renewable portfolio standards. Other renewable resources such as geothermal, tidal, wave, biomass and solar are not currently available in large enough quantities to be included in utilities' renewable energy strategies. Thus the emphasis on the acquisition of wind power has become universal in the utility planning world. This has created high demand for wind resources, particularly on the west coast where Northwest utilities are not only competing amongst one another for limited wind resources but with utilities in other western states, particularly California, that have aggressive renewable portfolio standards and are allowed to acquire Northwest wind resources to meet their renewable targets. All of this competition has created a scarcity of wind turbines and driven up the capital costs as well as the operation and maintenance costs associated with new wind resources.

Expiring Resource Contracts

Table A-6 illustrates that PSE needs to acquire additional resources to serve load in future years primarily due to load growth and, to a lesser extent, due to the expiration of existing resource contracts. In the past, long-term resource contracts, 15 – 20 years in length, was the norm. This is no longer the case as resource owners and purchasers prefer shorter term flexible contracts such that parties can respond to future risks, such as regulatory changes, fuel price escalation, etc. The power supply market has therefore become very fluid and accessible.

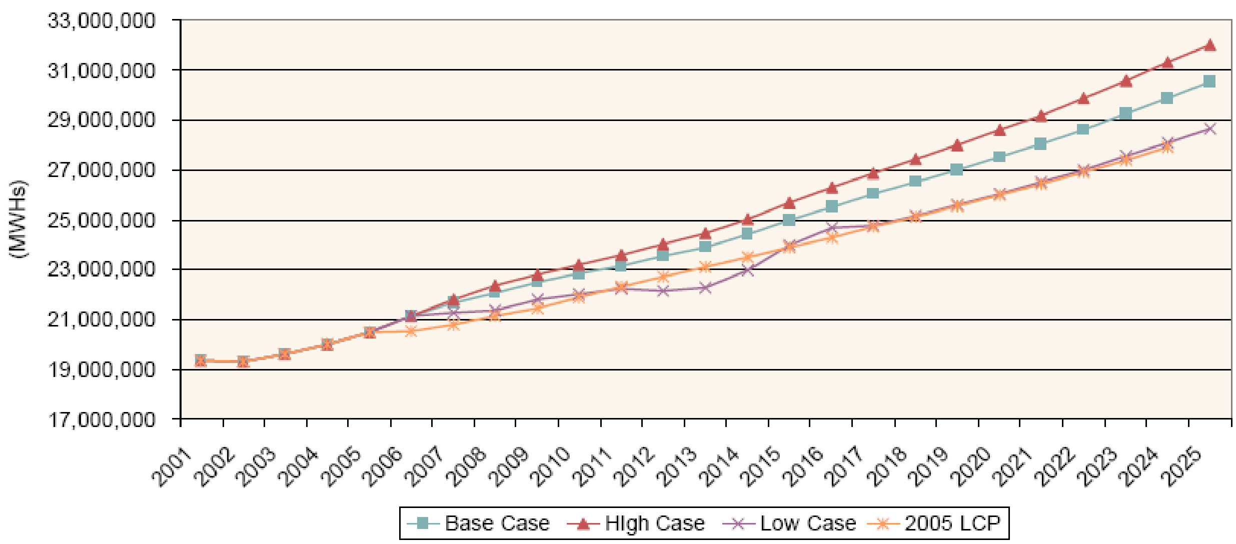
The NUG (non-utility generator) supply shown in Table A-6 consists of cogeneration plants that use natural gas to generate electricity and steam for industrial processes. All three of the cogeneration plants are located in Skagit and Whatcom counties. As shown in Table A-6, contracts with NUGs expire between 2012 and 2013.

Hydroelectricity, which provides the largest percentage of power supply in the existing resource portfolio includes owned resources and purchased power via long-term contracts with three public utility districts. As shown in Table A-6, the amount of power purchased under the long-term contracts decreases between 2011 and 2013.

Service Territory Growth

The load forecast establishes the basis for which resource acquisition decisions are made. The base case load forecast included in PSE's 2007 IRP assumes electric sales grow annually at an average rate of 2 percent. As shown below in Table A-7, this translates into base case loads growing from just over 21,000,000 MWh in 2006 to just over 30,500,000 MWh in 2025.

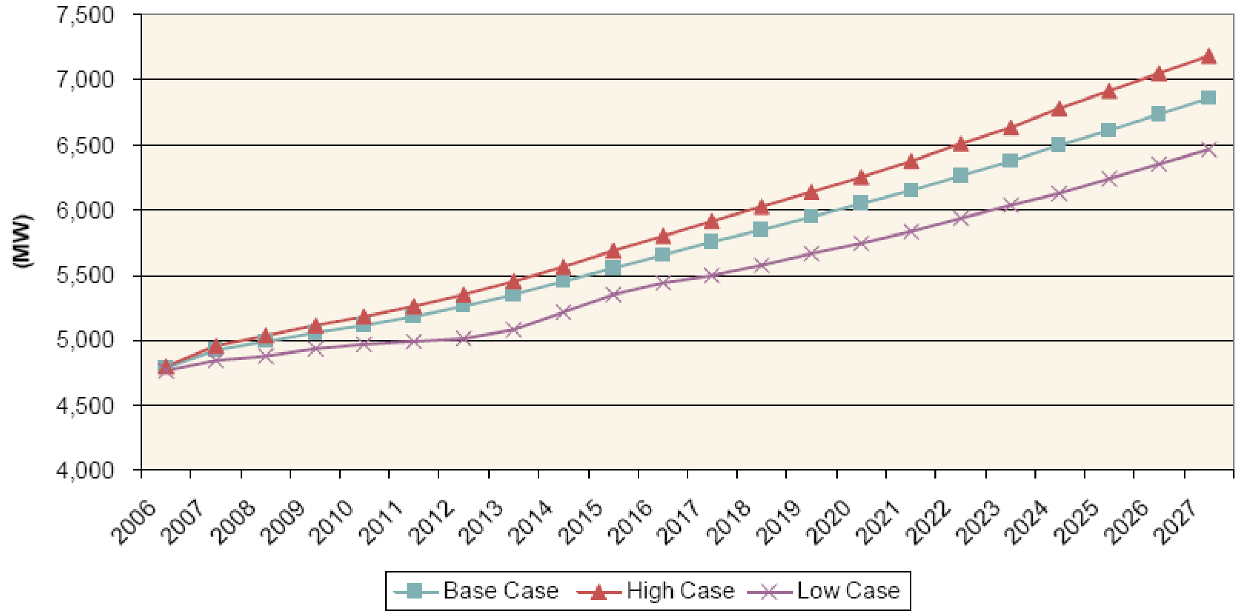
Table A-7
Electric Sales Forecast



Source: PSE 2007 IRP

The base case load forecast also includes an expectation that peak hourly loads will increase by 1.7 percent annually between 2006 and 2025 up from 4,792 MW to 6,616 MW as shown in Table A-8.

Table A-8
Peak Demand Forecast



Source: PSE 2007 IRP

The base case load forecast assumes the total number of electric customers increases at an average rate of 2 percent per year. This growth rate would translate into an increase from 1,039,372 customers in 2006 to 1,500,647 in 2025.

Due to the dependence on major commercial and manufacturing industries, the economy in PSE's service territory is dependent on the performance of national and state economies. The base case load forecast includes an expectation that employment in PSE's service territory will increase at an annual rate of 1.4 to 1.5 percent and that the U.S. economy will grow at a rate of 2.8 percent annually. The high case load forecast assumes a faster growth rate of 3.3 percent for the U.S. economy, low inflationary rates and high productivity growth. The low case load forecast assumes a slower growth rate of 2.3 percent for the U.S. economy, high inflationary rates and low productivity.

PSE's electrical infrastructure is very old with some of the components operating since 1917. With loads projected to increase 2 percent annually, PSE faces significant challenges and capital costs in order to maintain and upgrade its system to reliably serve future loads. PSE's 5-year infrastructure plan is designed to maintain existing facilities and add new components as necessary. In its 2007 IRP PSE identifies the following alternatives for addressing electric system capacity and reliability issues.

- Add new substation
- Strengthen feed to local area (new conductor)
- Improve existing facilities (substation modification, expand right-of-way, uprate system, rebalance load and modify automatic switching schemes)

- Load reduction (distributed generation, fuel switching, conservation, load control equipment and new tariffs)

The 5-year infrastructure plan included in the 2007 IRP identifies 20 new substations, all with 25 MVA transformers, to be built in PSE's service territory between 2007 and 2011. These include 4 new substations in Whatcom County, 2 new substations in Jefferson County and 1 new Substation in Skagit County.

Regulatory Impacts

It is important to keep a few key regulations in mind when projecting rates in the future. These regulations will impact the type of power that utilities can purchase from BPA and other (non-federal) suppliers.

The Renewable Portfolio Standard (RPS) mandated via I-937 requires large utilities (25,000 customers and greater) to obtain a percentage of their electricity from new renewable resources, such as solar and wind, or conservation. In addition, Substitute Senate Bill 6001 (SSB 6001) establishes statewide greenhouse gas (GHG) emissions reduction goals, and imposes an emissions performance standard on new long term base load electric generation that commences operation after July 2008. The law will impose significant restrictions on the procurement of fossil-fuel-fired generation. Coal-fired generation (both pulverized coal and integrated gasification combined cycle technologies) produces GHG emissions in excess of the new emissions standard of 1,100 pounds of CO2 per megawatt hour. The law effectively bars Washington utilities from entering into long term financial commitments for coal-fired generation unless the project successfully utilizes some form of carbon sequestration.

Additional legislation has been enacted or is on the horizon that will impact how electric utilities deal with issues related to carbon emissions. In 2008, the Washington legislature enacted into law House Bill 2815 (HB 2815) which among other provisions requires certain state agencies to work with the Western Climate Initiative, a partnership of six states and two Canadian provinces to design for a regional multi-sector market-based system to limit and reduce GHG emissions. This could be the first step in setting up a cap and trade market for carbon emissions. There are also efforts underway at the federal level to institute a national cap and trade system. In 2008, Congress failed to pass the Lieberman-Warner bill which proposed to allocate carbon allowances to load serving utilities and generators with carbon emissions through a cap and trade program. The allowances diminish over time as generators must decide whether to invest in abatement equipment or purchase allowances at the market in order to offset emissions. Congress is expected to take up the issue of cap and trade legislation again in 2009. The general consensus is that cap and trade legislation will have a better chance of passing in 2009.

New Resource Options

In order to determine future power supply rates, it is necessary to determine available resources and the cost of new resources. Non-federal supply-side resource options include a wide array of generation technologies and market mechanisms. Generation technologies include fossil-fueled resources (e.g., gas-fired and coal plants), nuclear, and renewables (e.g., wind, solar, geothermal). Wholesale market purchases are also included as a supply-side resource option.

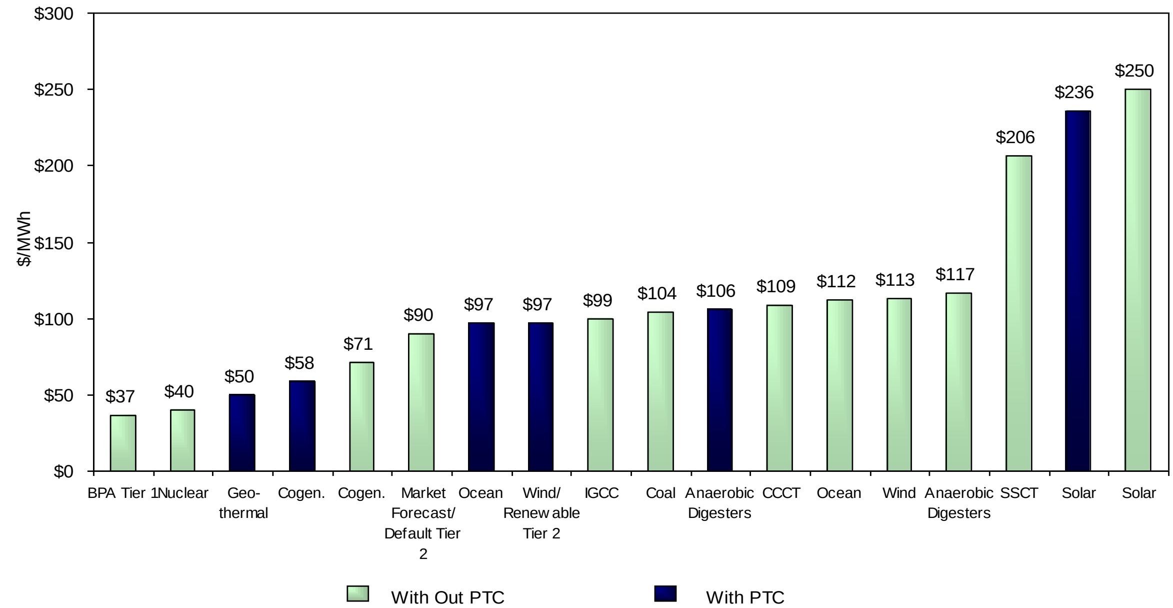
Estimated cost information for both renewable and non-renewable resources is based on current market prices for plant equipment and a survey of published resource planning studies. The Council's 5th Power Plan (updated January 2007) and Integrated Resource Plans (IRPs) developed by regional utilities in the Pacific Northwest in 2007 were surveyed to provide a benchmark for capital, fixed and variable O&M, and environmental mitigation costs. Due to recent technological advancements in wave and tidal powered generation, studies from the Electric Power Resource Institute (EPRI) were employed to estimate the cost of wave and tidal powered generation. Cost estimates were reviewed by internal EESC engineers to ensure that the cost assumptions are consistent with current market construction costs for the various resources considered. Using this data, average costs were calculated and used as estimates for base case resource costs.

Non-renewable resources considered include coal, IGCC, nuclear, Combined Cycle Combustion Turbine (CCCT), and Simple Cycle Combustion Turbine (SCCT). Fuel costs associated with these resources were based on calculating natural gas commodity prices using an assumed average annual market heat rate of 8,000 Btu/kWh and the market price forecast fuel prices included in regional studies and published forward natural gas prices.

Renewable resources considered include wind, wave, geothermal, landfill gas, biomass cogeneration, dairy-based anaerobic digesters and solar. The benefit of renewables lies in the expectation that most resource options have environmentally appealing aspects. In addition, renewable projects can provide protection against fuel price risk. Renewable projects also provide diversification of fuel consumption limiting the risks associated with relying on one type of fuel which may have volatile prices.

Table A-9 summarizes nominal 20-year levelized costs of supply-side resources options. Forecast BPA Tier 1 rates are included for comparison purposes. Renewable resource costs are shown with and without the federal production tax credit (PTC). The PTC is a significant cost factor as illustrated by the fact that wind power with the PTC has a lower cost than a CCCT, IGCC and coal and a higher cost if the project is not eligible for the PTC. The coal resource shown below does not include the costs associated with CCS technology.

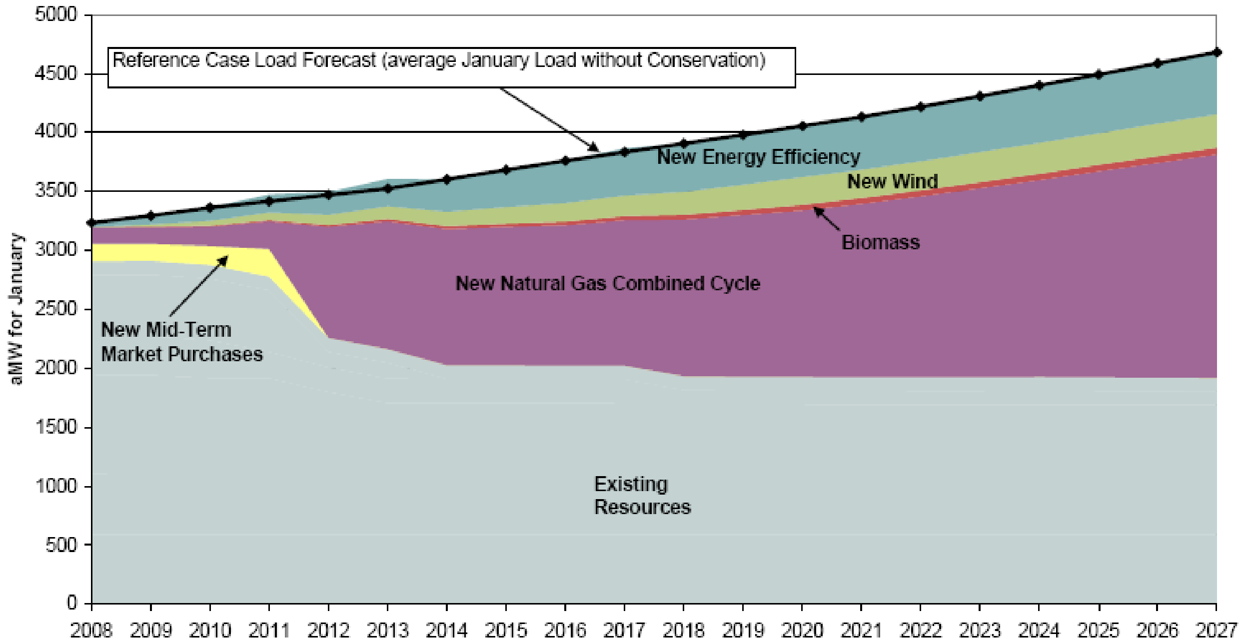
Table A-9
Resource 20-Year Levelized Costs
2008 Dollars



PSE's 2007 IRP Proposed Portfolio Strategy

The recommended portfolio strategy in PSE's 2007 IRP calls for increases in demand-side resources via energy efficiency programs, wind and a small amount of biomass resource acquisitions to meet renewable portfolio standards and natural-gas fired generation to meet PSE's remaining power supply requirements. Table A-10 graphically illustrates the new resources PSE intends to deploy in order to fill in the resource gaps shown in Table A-6.

Table A-10
PSE 2007 IRP Preferred Portfolio Strategy



Source: PSE 2007 IRP

Through the IRP process PSE identified the portfolio strategy illustrated in Figure A-7 as the "lowest reasonable cost resource strategy". In doing so PSE noted that it will reassess the trade-offs between gas and coal if CCS technology proves to be viable. Based on current CCS research activities PSE believes it will know by 2012 if CCS technology can be employed by 2021. As such, the preferred portfolio strategy could be altered in later years to include coal with CCS technology. It is important to note the exposure to natural gas price volatility in PSE proposed plan. The majority of new resources will consist of natural gas fired resources. Recent history has shown that the potential rate impact of relying on natural gas could be significant as demonstrated by PSE's continued requests for significant power cost rate increases as gas prices have been increasing in the last 5 years.

Forecast of PSE Power Costs

To compare power supply costs for a new public utility purchasing from a combination of BPA tiered rate products and/or the market to PSE power supply costs, the average system costs (ASC) included in the 2009 PSE ASC Report were used to assess PSE's power costs associated with its existing resource portfolio. The ASC costs were published as part of BPA's WP-07 supplemental wholesale power rate adjustment proceeding. PSE staff worked with BPA staff on the assumptions that went into calculating PSE's ASC. While these ASCs are not yet final, we believe they are the best benchmark currently available. The ASCs include the costs associated with generating and transmitting power to serve PSE's customers. In the 2009 PSE ASC Report, annual average system costs are provided in $/MWh for 2009 through 2013. ASCs were escalated by 2 percent annually beginning in 2013.

The costs associated with new resource additions were estimated using the new resources included in the 2007 IRP preferred portfolio strategy shown above. This resource plan includes adding new wind and natural gas resources. The natural gas resources included in the preferred strategy include both combined- and simple-cycle combustion turbines (CCCT and SCCT). The melded cost of PSE future resources was calculated by taking the weighted average of the ASC for existing resources and the new resource costs for new resources. The resource costs that were included in this calculation are shown below in Table A-11. The new resource costs shown below are based on the heat rates, availability factors, capital costs and operation and maintenance costs included in the PSE 2007 IRP. An exception to this is that the capital costs associated with wind were increased from $2,000/kW to $2,500/kW to reflect cost increases experienced by wind developers over the past year.

Fuel prices are highly volatile and have a significant impact on the costs associated with thermal resources. Historic daily fuel prices are used to examine daily fluctuations in the future; however, long term estimates depend on supply and demand for fuel which is both heavily influenced by several integrated factors that are difficult to predict. The volatility in natural gas prices will impact PSE's power supply costs (and therefore retail rates) significantly in the future as PSE becomes increasingly reliant on natural gas fired resources.

Gas commodity prices included in the calculation of CCCT and SCCT costs were calculated using an assumed average annual market heat rate of 8,000 Btu/kWh and the forecast annual market prices included BPA's "FY 2009 Average System Cost Report for Puget Sound Energy" (the "2009 PSE ASC Report") circa July 8, 2008. This methodology and market price forecast were utilized so that an apples-to-apples comparison could be made to the forecast of PSE's average system costs that are included in the ASC report. Using this methodology delivered gas prices were assumed to be $7.6/MMBtu in 2010, increasing to $9.8/MMBtu in 2020 and $12.3/MMBtu in 2029. Forecast delivered gas prices include an assumed transportation fee of $0.5/MMBtu in 2010 escalating at 3 percent annually to $0.9/MMBtu in 2029.

The new resource costs shown below include transmission costs. Transmission costs were estimated by applying a 1 percent escalator to BPA's current transmission rates (base, load shaping, scheduling, control and dispatch, generation reserves, regulation and frequency response and spinning and supplemental reserves). The 2010 transmission charge is assumed to be $2.71/kilowatt-month. The wind resource costs shown also include firming/integration charges equal to $10.6/MWh in 2010, escalating at 3 percent annually.

Table A-11 Forecast of PSE Existing and New Resource Costs ($/MWh)					
Year	**PSE Existing Resources**	**New Wind Resources**	**New CCCT Resources**	**New SCCT Resource**	**Melded PSE Power Supply**
2010	58.4	96.3	77.6	94.1	59.6
2011	59.1	98.2	79.4	96.3	61.0
2012	59.7	100.1	81.2	98.6	65.6
2013	60.4	102.1	83.0	100.9	67.5
2014	61.6	104.2	84.9	103.3	69.3
2015	62.9	106.3	86.9	105.7	71.0
2016	64.1	108.4	88.9	108.2	72.8
2017	65.4	110.6	90.9	110.8	74.9
2018	66.7	112.8	93.0	113.5	77.4
2019	68.1	115.0	95.2	116.2	79.7
2020	69.4	117.3	97.4	119.0	82.0
2021	70.8	119.7	99.7	121.8	84.2
2022	72.2	122.1	102.0	124.8	86.6
2023	73.7	124.5	104.4	127.8	89.0
2024	75.1	127.0	106.9	130.9	91.4
2025	76.7	129.5	109.4	134.1	93.9
2026	78.2	132.1	112.0	137.3	96.4
2027	79.7	134.8	114.7	140.7	99.2
2028	81.3	137.9	117.4	144.1	102.0
2029	83.0	141.1	120.2	147.7	104.8

The preferred resource portfolio in PSE's 2007 IRP includes a new 746 MW CCCT coming on-line in 2012. There is a significant (7.5 percent) increase in PSE's melded power supply costs between 2011 and 2012 due to this resource addition. Cost increases in other years are more modest because the IRP doesn't call for such large resource additions. On average the PSE melded power supply costs shown above increase by 3 percent annually.

Table A-11 shows PSE's power supply costs increasing from $59.6/MWh in 2010 to $71.0/MWh in 2015 (19 percent increase), $82.0/MWh in 2020 (38 percent increase), $93.9/MWh in 2025 (58 percent increase) and $104.8/MWh in 2029 (76 percent increase), the end of the 20-year study period. In PSE's July 2008 ASC filing power supply costs were 70 percent of total revenue requirements. Assuming power supply costs are 70 percent of total costs, the power cost increases would translate into retail rate increases of 13 percent in the first 5 years, 26 percent over the first 10 years, 40 percent over 15 years and 53 percent over the 20-year study period. These rate increases would translate into an increase in residential retail rates from the current 9.3 cents/kWh to 10.5 cents/kWh in 2015, 11.7 cents/kWh in 2020, 13.0 cents/kWh in 2025 and 14.2 cents/kWh in 2029.

PSE Wires Rate Forecast

Wires expenses are those expenses associated with traditional distribution facility construction, operations and maintenance, customer accounts, customer services, and administrative and general (A&G) expenses.

The comparison of distribution costs between PSE and public ownership is more straightforward than for the power supply costs discussed above. In general, it is not anticipated that local distribution rates of PSE will differ materially from the rates charged by a new public utility. Differences can occur based on individual circumstances, but the new utility will need to provide the generally same services and upgrades as would be provided by PSE. A new public utility may benefit compared to PSE due to its much lower cost of capital but this benefit has not been included in this report.

Based on PSE's ASC filing, the recent rate increase and PSE's description of additional capital requirements for the distribution system, a low and base case forecast of wires rates were developed for PSE. This forecast is provided in Table A-12.

Table A-12
Forecast of PSE Wires Costs ($/MWh)

Year	Low Projected Wires Cost	Base Projected Wires Cost
2010	25.0	30.0
2011	25.5	30.6
2012	26.0	31.2
2013	26.5	31.8
2014	27.1	32.5
2015	27.6	33.1
2016	28.2	33.8
2017	28.7	34.5
2018	29.3	35.1
2019	29.9	35.9
2020	30.5	36.6
2021	31.1	37.3
2022	31.7	38.0
2023	32.3	38.8
2024	33.0	39.6
2025	33.6	40.4
2026	34.3	41.2
2027	35.0	42.0
2028	35.7	42.8
2029	36.4	43.7

Potential Wires Cost Savings

A significant component of a utility's overall costs is associated with meeting the costs of its capital expenditures. While the analysis performed in this report assumes the wires rate stay the same under either utility option, a new public utility may be able to realize additional savings due to lower financing costs for public utilities as compared to PSE options. A new public utility under certain circumstances will be eligible to obtain financing at a tax-exempt rate, which is much lower than the cost of capital experienced by any investor owned utility. Alternatives to taxable revenue bonds include obtaining financing from a large commercial bank. Revenue bonds are considered to be the least cost and most efficient form of financing. However, the new utility should evaluate its options more closely once a final organizational structure is decided upon and an acquisition appears more imminent.

The amount of these capital costs in a utility's rates is a function of the overall size of the planned capital expenditures and the way in which these costs are funded. In addition, in the case of a purchase of existing facilities, the new utility will need to finance the purchase of the existing facilities. While PSE's average weighted cost of debt after tax is approximately 10 to 11 percent, public utilities are borrowing money today at rates between 4 and 5 percent. This difference is very significant and can translate directly into savings to the rate payers.

According to PSE, a lower PSE credit rating would detrimentally impact PSE's access to capital and make it difficult for PSE to operate[1]. PSE states that the actual effects would be determined, in part, by the level of the downgrade. The impact of a downgrade would include, but would not be limited to, the following:

- Higher long-term borrowing costs on long-term debt, preferred stock, hybrid securities, etc.;
- Higher short-term borrowing costs as reflected in credit facility pricing grids and likely higher spreads on commercial paper issuances;
- Potential loss of access to the commercial paper markets;
- Possible inability to renew credit facilities;
- Potential collateral calls from energy credit counter parties;
- The demand for collateral or up-front payments by those providing new energy resources to PSE;
- Counterparties may no longer provide trade credit for energy hedging activities;

Additional savings for a public power utility can also materialize due to opportunity for increased efficiency through integrated utility operations. For example, many existing PUDs are already providing other utility services to their communities. These PUDs already have customer service and customer accounting infrastructure in place. The addition of electric service could improve local government efficiency through sharing of personnel, equipment and supplies across utilities.

[1] Puget Energy's Vice President of Finance and Treasurer, in PSE Response to Public Counsel Data Request No. 026(d) in the concurrent Rate Case

PSE Rates in Context with Northwest Public Power Alternatives

BPA Power Supply

BPA is a federal agency that markets wholesale electricity and transmission to the Pacific Northwest's utilities. Because BPA markets energy from its hydro generation and transmission at cost, rather than at market prices, it has traditionally provided some of the lowest cost electricity in the nation. BPA provides about half the electricity used in the Northwest and operates over three-fourths of the region's high-voltage transmission. As such, the future price and availability of BPA power is a critical factor in evaluating future power supply costs.

A new public utility in the Northwest has two options for receiving the benefit of the Federal Columbia River Power System ("FCRPS") through BPA. The first option is to sign a contract with BPA and obtain a share of the FBS power available. The second option is to pursue exchange benefits for the residential and small irrigation customers of the utility. This section provides some background information on each of these options.

Future BPA Rates

BPA Columbia River dams provide low-cost reliable power to the Northwest region. Because of these dams the electricity prices in the Northwest have historically been below the rest of the nation. However, due to growth in electricity consumption, power supply requests placed on BPA are projected to exceed the power generation from these dams. In order to address this issue, BPA has developed a new proposal for offering power supply products.

BPA is proposing two different pricing tiers for future power contracts beginning in October 2011. Tier 1 is intended to capture the costs of BPA's current resources and Tier 2 is intended to capture the costs of additional resources acquired by BPA to serve its customers' loads in excess of their Tier 1 allocation. The general structure of the products that BPA intends to make available at Tier 1 rates will remain essentially unchanged from the products that it currently provides. BPA is proposing to offer a variety of Tier 2 rate alternatives which are described later in this section. Rate forecasts have been developed for both Tier 1 and Tier 2 for the study period.

BPA is preparing to offer new contracts to its customer utilities that will be radically different from the current agreements. The contracts will, for the first time, limit the amount of power that customers can buy at melded, cost-based rates. The limit for each customer will be calculated based on 2010 loads. BPA will sell this limited power at rates that are based on the embedded costs of the existing federal system. Any additional power that customers need will only be available at incremental prices. BPA customers can elect to purchase additional power from

BPA at Tier 2 rates or from non-federal resources or a combination of the two. An impact of this change is that power from the existing system (known as Tier 1) is almost guaranteed to be the lowest cost resource available to utilities, but any additional power from BPA is may not be lower cost than other, non-federal market alternatives.

Under BPA's proposal, customers' allocations of Tier 1 power will be determined based upon actual loads less committed resources or the High Water Mark (HWM) during the period October, 2009 through September, 2010 (FY 2010). HWMs will also be created for new public utilities that form after the initial HWM contracts are executed. HWMs for new publics (including new Tribal utilities) will be limited to 250 aMW in aggregate total during the term of the HWM contracts, of which only 50 aMW will be added in any single rate period (every two years). While this limited access to lower cost BPA power has not yet been tested in court, this report assumes that the limits will remain in place.

Once a new public utility qualifies for service under BPA's standards of service, it must provide a three-year binding notice before it will be eligible to purchase power from BPA using its HWM (i.e. before it can purchase Tier 1 power). If a new utility satisfies BPA's standards of service on December 31, 2009, it could begin purchasing Tier 1 power in January 1, 2013. For at least the first three years of operation the new utility would likely have to purchase all of its power supply at BPA Tier 2 or market prices. In addition to the three year waiting period, BPA is proposing to release the 200 MW reserved for new public utilities in annual 50 MW increases. Thus a new public utility with a load greater than 50 aMW would need to purchase some market-based power, at least in the early years, even after the waiting period. If requests by new publics exceed the 50 aMW rate period limit, BPA will phase in the HWMs for new publics proportionally. If new requests exceed the 250 aMW limit, each new request will be proportionally reduced. An additional complication in determining how much Tier 1 power a new public utility would receive is the fact that BPA has reserved 40 aMW of the 250 aMW for new Tribal utilities. So, the amount of Tier 1 power a hypothetical new public utility would receive is dependent on the amount of Tier 1 service requested by other new public and Tribal utilities.

While the details related to the Tier 1 and Tier 2 resources are complicated, BPA does provide a significant benefit to the regions public utilities as a power supplier. BPA has significant experience operating a very complex hydro system and has experience operating in the active power markets. In addition, BPA is an important player in the West coast power markets, both as a seller and buyer, and could obtain favorable prices due to the size of purchases and the financial stability of the organization. Finally, in the uncertain wholesale electric market, public power utilities are guaranteed access to BPA power, significantly increasing their options and reducing their risks.

Table A-13 below provides different scenarios in which a hypothetical 200 aMW new utility would purchase varying amounts of Tier 1 and market-priced power.

Table A-13 New Public Utility Purchase Scenarios (aMW)					
		Scenario 1 – Full HWM/Tier 1		*Scenario 2 – 50% of HWM/Tier 1*	
Year	**Purchased Power Requirements (1)**	**Tier 1 (2)**	**Market (3)**	**Tier 1**	**Market**
2010	200	0	200	0	200
2011	204	0	204	0	204
2012	208	0	208	0	208
2013	212	50	162	25	187
2014	216	50	166	25	191
2015	221	100	121	50	171
2016	225	100	125	50	175
2017	230	150	80	75	155

(1) Assumes new public utility satisfies BPA's standards of service and applies for a HWM on December 31, 2009.
(2) Incremental Tier 1 service to new publics limited to 50 aMW each rate period (every two years). Assumes HWM is equal to 2010 load of 200 aMW.
(3) Market purchase could be via a BPA Tier 2 product or a non-federal purchase and could be renewable or non-renewable energy.

Using the assumptions included in Table A-13 for a hypothetical new public, a third scenario would be that no Tier 1 power is available and the new public's load must be served using only market-priced power. Scenarios 1 (full Tier 1 service available) and 3 (no Tier 1 service available) would provide the bookends for the new public power supply scenarios, with Scenario 2 (half of the desired Tier 1 purchase available) falling between these values. The forecast power supply costs associated with each of these scenarios will be examined in the next section of this report. Forecast Tier 1 prices are only a third of forecast market prices. As such, forecast power supply costs vary greatly between scenarios.

Availability of BPA Resources for New Publics

According to the current BPA proposal, the amount of low cost BPA power available for new publics (including new Tribal utilities) will be limited to 250 aMW in aggregate total during the term of the HWM contracts of which only 50 aMW will be added in any single rate period (every two years). Putting this limitation in perspective, BPA's 250 aMW reserve for newly formed public utilities could serve all residential customers in a service territory with a population of 350,000 to 400,000. If both residential and commercial customers are served, the BPA set aside would provide for a service territory with a population of 150,000 to 200,000 As this study demonstrates, access to BPA's low cost power supply will be very important for the creation of a new public utility that expects to charge lower rates than PSE will be offering.

In the 1970s, threats of insufficient resources to meet the region's electricity demands led to passage of the Northwest Power Act. In that Act, Congress, among other things, provided that BPA's public agency customers had a statutory right for service from BPA to meet their net requirements loads. BPA therefore has the obligation to serve public utilities in the Northwest.

Forecast of Public Utility Power Costs

The next step in the analysis explored the cost of resources to a new public utility. As discussed previously, different assumptions related to the amount of BPA Tier 1 power will significantly impact the power supply cost to the utility. As Table A-9 demonstrates, Tier 1 power is significantly lower priced compared to any new resource or market purchase.

Three resources were considered in the calculation of power supply costs for a new public utility: BPA Tier 1, Mid-Columbia ("Mid-C") market and a generic wind project. The Mid-C market and generic wind project costs are dependent on many variables and should be considered illustrative of current pricing trends.

Forecast wind costs include the following assumptions:

- Capacity factor = 30 percent
- Fixed operation and maintenance costs = $43/MWh, escalating at 3 percent annually
- Variable operation and maintenance costs = $2/MWh, escalating at 3 percent annually
- Firming/integration = $10/MWh, escalating at 3 percent annually
- Capital costs = $2,500/kilowatt
- Production tax credit = $20/MWh, escalating at 3 percent annually
- Borrowing rate = 5 percent

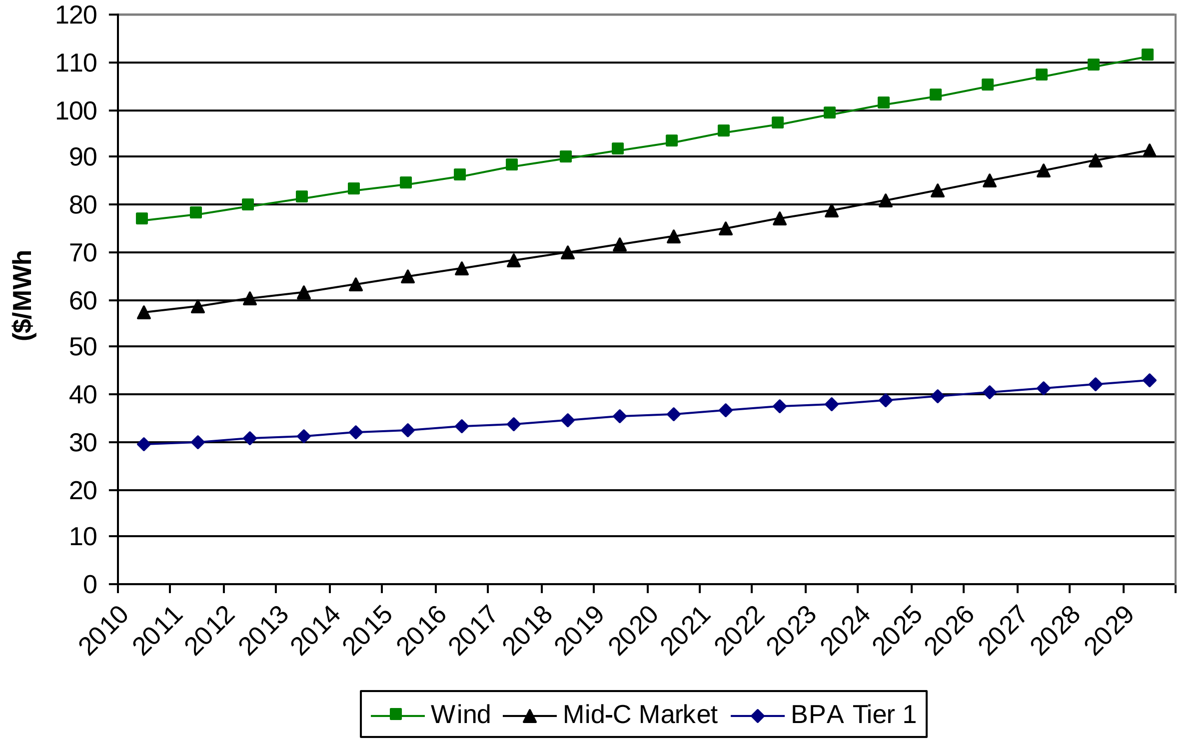
The capacity factor, O&M and capital cost assumptions per the assumptions for a generic wind resource in the PSE 2007 IRP. The borrowing rate is based on the estimated borrowing rate that a public utility could acquire today, rather than what PSE would have to pay. The analysis assumes that Congress extends the PTC through December 31, 2009 and that the PTC is applicable for the first 10 year of operation. The firming/integration costs are based on BPA's current wind integration charges and forecast firming charges included in regional studies (including results shown in the Northwest Power and Conservation Council's March 2007 Northwest Wind Integration Action Plan).

Forecast Mid-C markets included in this analysis are per the prices included BPA's "FY 2009 Average System Cost Report for Puget Sound Energy" (the "2009 PSE ASC Report") circa July 8, 2008. This particular market price forecast was used so that an apples-to-apples comparison could be made to the forecast of PSE's average system costs that are included in the ASC report.

For this study BPA Tier 1 rates were assumed to be based on current priority firm on- and off-peak energy, demand and load variance rates escalated at 2 percent annually beginning in 2010.

The base case forecast resource costs are shown below in Table A-14.

Table A-14
Forecast Base Case Resource Costs



The resource costs shown above are assumed to be reflective of the resource options available to a new utility. Power supply costs for Scenarios 1 and 2 will be estimated later in this report using the resource costs shown above and the purchase quantities (aMW) shown in Table A-6. Estimated transmission costs are also included in the estimated power supply costs. Transmission costs were estimated by applying a 1 percent escalator to BPA's current transmission rates (base, load shaping, scheduling, control and dispatch, generation reserves, regulation and frequency response and spinning and supplemental reserves). The 2010 transmission charge is assumed to be $2.71/kilowatt-month or $4.6/MWh assuming a load factor of 63 percent.

Comparison of Power Supply Options for New Publics

New public utilities could either sign a contract with BPA that includes the proposed tiered rate methodology (TRM) or sign an alternative contract. Under this scenario a new public utility's power supply would consist of the following:

- Purchase Tier 1 power to the extent available under the 200 aMW allocation to new publics (including the 50 aMW phase in included in TRM)
- Purchase non-federal power or a BPA Tier 2 product to serve load requirements above its HWM (assumed to be market-priced power for study purposes)

Two scenarios were examined in this study under the above power supply portfolio. In one scenario the new public utility would receive Tier 1 power equal to its HWM. In the second scenario the new public would only receive 50 percent of its HWM via a Tier 1 purchase. The relevant purchase amounts are shown in Table A-13.

The other power supply option we have included in this analysis for comparison purposes is the "status quo" scenario. In this scenario we have calculated estimated power supply costs for the new public assuming it remains in PSE's service territory. In this case the estimated power supply costs are based on the following:

- Purchase all power requirements at PSE's Melded Power Costs (as shown in Table A-11).

We have estimated a range of power cost savings under both new public compared to the status quo scenario detailed above. The results are summarized below.

Range of Power Costs Savings for New Publics that Sign a TRM Contract with BPA

Based on the assumed PSE power supply costs for existing and new resources and forecast BPA Tier 1 and market prices detailed above a range of power cost savings was calculated for a new public that signs a TRM contract and receives either all of its HWM at Tier 1 rates or half of its HWM at Tier 1 rates (as shown in Table A-13).

The estimated retail rate increases reflect total rate increases between 2010 and 2029 and assume that 70 percent of PSE's revenue requirement is attributable to power supply costs. Table A-15 below show 20-year net present values (NPV) of total power supply costs assuming a discount rate of 5 percent. NPV is a calculation which represents a future stream of benefits or costs into a value today. Costs and benefits are generally examined on a NPV basis in order to compare future streams in a consistent manner.

Table A-15
Comparison of Power Supply Costs

	Full HWM/Tier 1	**50% of HWM/Tier 1**	**Status Quo =PSE Resource Cost**
20-Year NPV of Power Costs (millions)	$1,461	$1,718	$2,035
Difference from Status Quo NPV (millions)	($574)	($317)	NA
Percent Difference	(28%)	(16%)	NA
Estimated Retail Rate Difference from Status Quo	(20%)	(11%)	

Table A-15 shows that retail rates would be 28 percent less than the status quo if the new public utility could purchase all of its HWM at Tier 1 rates and 16 percent less if only half of its HWM could be purchased at Tier 1 rates. This assumes that power supply costs are 70 percent of the utility's total revenue requirement.

As shown above 20-year NPV savings range from $317 million to $574 million depending on the share of power supply the new public utility can acquire at Tier 1 rates. These savings would translate into retail rates that are 11 to 20 percent less than the status quo (purchasing from PSE).