

Financial Considerations

Financial considerations play a part in resource planning and acquisition because, in order to fulfill our responsibilities, PSE requires continuous access to capital markets on reasonable terms, available credit to operate the business, and the capability to execute risk management strategies.

Section I, Primary Considerations, discusses the most important of these considerations:

- the company's credit rating and how it affects the cost of credit for financing and risk management activities
- imputed debt cost associated with purchased power agreements (PPAs) and how it affects that credit rating
- financial considerations that were applied to this IRP analysis.

Section II, Further Considerations, contains:

- a detailed discussion of imputed debt issues
- summaries of relevant changes in financial accounting standards
- a description of risk management activities
- an explanation of the production tax credit and other tax incentives applied to certain resources

I. Primary Considerations

A. Credit Rating Significance

In general, financing for ongoing operations and new capital requirements comes from funds generated internally through operating cash flows, and from funds raised externally from both the debt and equity capital markets. PSE's historic reliance on purchased power does not generate cash flow, which other utilities generate from the recovery of depreciation of owned resources through rates charged to customers. Without this source of cash inflow, PSE expects to be a net borrower in order to fund the growth and maintenance of our transmission and distribution system, and the purchase of new resources. As such, continuous access to debt and equity capital markets is critical to PSE's successful execution of our capital spending plans.

To attract adequate and reasonable external debt financing, we must maintain an attractive credit and investment profile. Credit ratings are the primary measure used by investors to compare the creditworthiness of different companies. Moody's Investors Service and Standard and Poor's (S&P) are two of the major credit rating agencies.

PSE currently carries the lowest investment-grade credit rating (BBB-/Baa3). The rating affects the company in several ways. Generally, it makes our debt costs higher than they would be at a stronger rating; it limits our access to financial markets during periods of economic downturn or market stress (like credit market events, power cost fluctuations, regulatory, tax and political changes, wholesale market developments, and force majeure actions); and it provides limited cushion from a potential downgrade to non-investment grade status. Specifically related to resource planning, PSE's current rating

- increases the cost of borrowed funds used to finance capital expenditures like infrastructure improvements and new generation facilities
- limits the amount of unsecured credit extended by counterparties with whom we arrange for PPAs
- increases the cost of long-term PPAs, since providers will want compensation for the credit risk inherent in a long-term purchase contract.

Improving our credit rating to is a key part of our financial strategy. A stronger credit rating would give us better access to capital markets and a lower cost of capital, which

directly benefit customers through lower rates over time. It would increase our ability to access long-term fuel supply contracts. And it would increase our ability to access physical and financial hedging products that are a part of risk management.

PSE has taken substantial steps to strengthen the company's capital structure and achieve a higher credit rating. Since 2001, we have raised over \$500 million in new equity in three separate offerings. We have refinanced callable high-cost preferred stock and long-term debt, and increased our bank credit lines from \$375 million to \$700 million. Through this balanced approach to managing our debt portfolio, growing equity through the sale of stock, and retaining earnings, we plan to continue strengthening PSE's financial position, which we expect will lead to a higher credit rating over time.

B. Credit, Liquidity, and Risk Management

All energy transactions contain credit risk. PSE uses risk management strategies to reduce volatility in power and natural gas costs, manage unused capacity, and mitigate power costs through increasing the value of dispatching natural gas-fired electric generation plants. Execution of these risk management strategies, as well as executing future PPAs, requires credit.

In the energy industry, credit risk is defined as the potential loss resulting from a counterparty's failure to perform under one or more agreements for the purchase or sale of an energy service, energy product, or derivative thereof. Credit risk is typically calculated as the sum of amounts currently due and the replacement value of the energy under a given contract.

Firms with higher credit ratings are typically granted larger unsecured credit lines and are also able to transact with more counterparties compared to lower-rated companies. Since lower-rated firms tend to receive relatively smaller unsecured credit lines, they may be forced to rely on secured credit backed by collateral. Common forms of security used in the energy industry include cash collateral, and letters of credit issued by financial institutions such as commercial or investment banks. Posting collateral reduces liquidity and increases costs.

PSE uses liquidity facilities to fund its ongoing working capital needs. As of December 31, 2006, its facilities provided credit availability of around \$700 million through an unsecured \$500 million revolving credit line and a \$200 million accounts receivable

securitization arrangement. Credit available through the accounts receivable securitization program varies from around \$150 million to \$200 million, depending on accounts receivable and unbilled revenue balances. Given that these facilities are sized and are intended to be used primarily to fund working capital needs, they are typically not considered a source of credit to support energy credit risk. Instead, the Company relies on open trade credit from energy trading counterparties and a new credit facility established specifically to support energy hedging strategies.

Open trade credit provided by our energy trading counterparties helps address energy credit risk. Generally however, credit limits offered by these counterparties may be increased or decreased at any time; they vary in response to changes in the perceived risk of transacting with PSE.

During 2004 we informally surveyed the major counterparties with whom we execute these strategies to better understand the relationship between the Company's S&P and Moody's ratings and the unsecured credit lines provided. That survey indicated that an improved credit rating could expand our ability to enter into hedging transactions. On the other hand, a non-investment grade rating would significantly impair the company's risk management activities. Contracting parties would constrain open credit and would likely require collateral to maintain transacting activity. A downgrade would also trigger requirements to post collateral under several of our hedging instruments. While we might be able to access additional credit or equity to cover cash requirements, our weakened financial condition would significantly increase the cost of such capital and reduce liquidity.

In the January 2007 General Rate Case order, the WUTC approved recovery of hedging costs through the power cost adjustment (PCA) mechanism by including those costs in the Power Cost Baseline Rate. Specifically, the WUTC approved recovery of costs associated with establishing and maintaining liquidity facilities that support the company's hedging activities. In early 2007 the Company established a \$350 million credit facility specifically dedicated to supporting hedging activities. The facility includes a \$175 million accordion feature which could allow the facility to grow to \$525 million subject to approval by the bank syndicate. This facility enables the Company to provide letters of credit or to make cash draws for the purpose of providing collateral required in excess of open trade credit as trading positions change in value with market pricing or credit standing movements over time. While recovery of credit costs through the PCA is an improvement, it does not change the importance of PSE's credit rating in implementing

hedging strategies as a lower credit rating would simultaneously restrict open trade credit and increase costs under the hedging credit facility.

C. Purchased Power Agreements and Imputed Debt

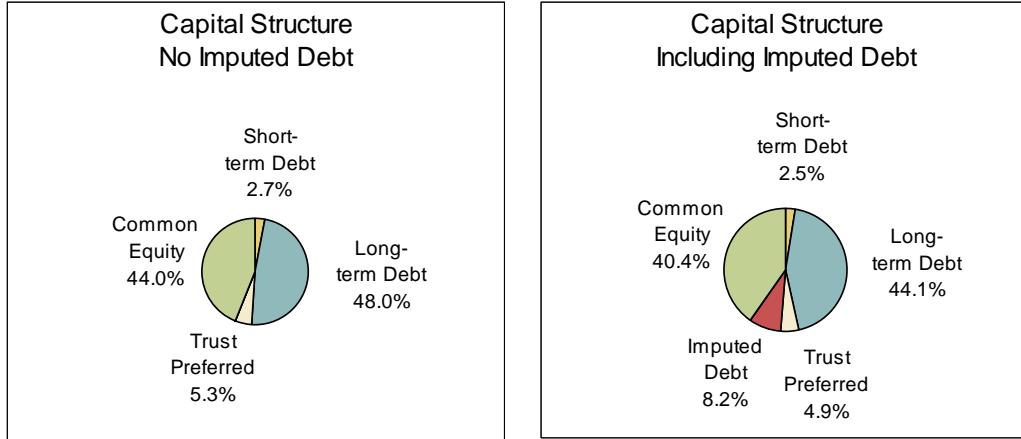
The extent of our reliance on PPAs increases the challenge of strengthening our credit rating. Rating agencies view electric utility PPAs as fixed commitments that affect a company's ability to cover debt obligations. Consequently, the agencies calculate (impute) debt associated with the capacity portion of payments made under these agreements.

PPAs are a useful resource strategy because they are an alternative to the risk and expense associated with new plant development, construction, and operation; however, they are not a physical asset and do not have an equity component. Therefore PPAs generally do not contribute to earnings, and related payments are viewed as a fixed obligation, similar to the interest on a bond. Applying imputed debt to PPAs decreases interest coverage ratios and is thus a negative factor in determining credit rating. Unless this imputed debt is offset by increased equity, it increases leverage in the balance sheet and reduces credit quality.

Our reliance on PPAs added more than \$425 million of imputed debt to PSE's year-end 2006 capital structure used in credit metrics analysis. Since the publication of our 2005 plan, S&P has modified its methodology: rather than a flat 10% imputed interest and discount rate, it bases the rate on a company's cost of debt. In 2006, PSE's discount rate changed from 10% to 7.7%, which increased our imputed debt by more than \$37 million. A majority of our energy and capacity supply comes from PPAs, so this change puts significant downward pressure on our credit rating. We have been working with the rating agencies since the early 1990s to convey that our imputed debt is somewhat mitigated by the low-cost structure of hydro-based contracts from the Mid-Columbia public utility districts.

As Figure F-1 shows, including \$425 million of imputed debt in the capital structure allowed by the WUTC in the 2007 General Rate Case reduces the equity component from 44% to 40.4%.

**Figure F-1
Capital Structure With and Without Imputed Debt**



Regulatory Treatment of Imputed Debt

Public utility commissions in California and Florida have recognized the impact of imputed debt on utility credit ratios

A literature search as of January 2007 indicates no changes in what was reported in the 2005 Least Cost Plan for Florida and California regulatory treatment of imputed debt. A December 2004 California Public Utilities Commission ruling on imputed debt or debt equivalence of PPAs (Decision 04-12-047) stated:

We decline to adopt a formal debt equivalence policy. However, we do recognize that debt equivalence associated with PPAs can affect utility credit ratios, credit ratings, and capital structure. Credit rating agencies have long recognized debt equivalence as a risk factor and we have and will continue to reflect the impact of such risk in establishing a fair and reasonable ROE and in approving a balanced ratemaking capital structure. In that regard, we have identified information that the utilities should provide in their annual cost of capital applications to enable us to better assess debt equivalence risks. Our goal is to provide the utilities with a fair and reasonable ROE and ratemaking capital structure that, among other matters, support investment-grade credit ratings.

The Florida Public Service Commission ruled in March 2004 (Docket 031093-EQ) that Florida Power and Light could account for imputed debt and make an equity adjustment to reduce the price paid for power purchased from small qualifying facilities. PSE has reviewed the major dockets at the Florida PSC web site, and has not found any evidence that would suggest any changes in their policy since 2004.

We have repeatedly found that consideration of any application of an equity adjustment should be evaluated on a case-by-case basis. We have reviewed FPL's petition, the cited S&P article, and past Commission decisions regarding the application of an equity adjustment in general, and for purposes of determining capacity payments under a Standard Offer Contract, in particular. At our request, FPL provided additional support for its position in the form of a second S&P report dated October 21, 2003. In this report, S&P indicates that it applies a 30% risk factor in its evaluation of purchased power obligations as part of its determination of the consolidated credit profile of FPL Group. Based on the above, we believe it is appropriate in this instance for FPL to make an equity adjustment as stated in the determination of capacity payments in its Standard Offer Contract.

D. Financial Considerations Applied to This IRP

In the course of developing our resource strategy, PSE considers how the selected resource portfolio and individual resources impact our incremental power costs and risk. In addition the impact on our financial strength and credit, and conversely whether our financial situation supports the resource choices, are further evaluated further during development of the annual strategic financial plan and also when a specific resource is considered for purchase or contract. The following considerations and assumptions were used during this IRP analysis.

- PSE could have a large capital need for resources concentrated over a few years prior to the time that NUG contracts expire in 2011-2012. While capital limitations during this time were not specifically analyzed in this IRP, we will need to examine the timing of replacement acquisitions to determine whether we have the financial strength to support rapid-owned resource additions.
- Short-term power bridging agreements (PBAs) are used in this IRP to cover need until long-lead resources become available. PBAs may also be used to stagger resource additions to moderate the year-to-year financing requirements of owned resources. For the generic power bridging agreements analyzed in the portfolios, we computed an equity offset cost adder to account for the effect of imputed debt. A similar approach will be applied when evaluating specific power purchase agreements during the resource acquisition process.
- The timing of regulatory recovery is not explicitly modeled in the IRP, but this may become a consideration for specific resource acquisitions. For long-lead resources, and possibly transmission, PSE may need to pursue recovery of costs for construction work in progress. Short-term retail rate changes are another potential concern.
- For evaluation of generic resources, both PPA contracts and natural gas fuel were priced at spot market without a risk management adder. This issue will be re-examined as we evaluate specific resource acquisitions.
- If the future coal market more closely resembles the natural gas market model, credit could become an issue for coal-fueled IGCC resources. This IRP does not include a credit adder for coal fuel.

II. Further Financial Considerations

A. Further Detail: Purchased Power Agreements and Imputed Debt

PPA Advantages and Disadvantages

PPAs provide PSE with an opportunity to avoid construction risk. Depending on the terms, a PPA may also avoid performance risk. If the terms are “take-or-pay,” we do not avoid performance risk because we pay whether or not the power is delivered. A “take-and-pay” PPA contract has less performance risk because we pay only when the power is available. While this risk mitigation is good, PPAs have some of the same risks as ownership and can also increase risk. As with plant ownership, PPAs can create an earnings lag when the full amount of the PPA cost is not allowed to be recovered through a power cost adjustment (PCA) mechanism until the next Power Cost Only Rate Case. PPAs can have increased risk compared to ownership due to loss of operational flexibility and counterparty risk.

With some PPAs, PSE does not have the operational flexibility to displace the contract when power is available in the market at lower prices. While a fixed-price PPA provides stability for the price of that power, it may not contribute to the lowest portfolio cost of all power needs. Plant ownership provides the operational flexibility of choosing to maintain and run the plant in a way that maximizes the plant’s useful life. PPA sellers, on the other hand, choose the maintenance schedule that is best for them and could offer their plant at current fair market value, giving PSE the choice of buying the plant outright. That opportunity to purchase the plant provides some flexibility to a PPA, but there is a perception that purchasing the plant means PSE is paying for the facility twice—once by purchasing the power through the PPA and once again at contract termination.

We can report mostly good experiences for counterparty risk, as our counterparties have fulfilled their commitment to deliver. But this is not always true, and could change in the future. For example, the provider of a contract for firm gas supply defaulted and PSE received only partial compensation for the cost of replacement gas. In 2006, at the request of the PPA suppliers, PSE was asked to consider restructuring two fixed-price PPAs because the seller is experiencing financial distress in the later years of the contract. Mitigation of counterparty risk is managed through credit relationships and limits.

Imputed Debt Methodologies

Utilities have used PPAs in the past as an alternative to the risk and expense of new plant development, construction, and operation. However, entering into long-term PPAs creates fixed obligations that can increase a utility's financial risks.

Both Moody's Investors Service and Standard & Poor's (S&P) use a quantitative methodology to calculate the risk of PPAs and the impact of that risk on the creditworthiness of electric utilities. The methodologies, while different from one another, were designed to make a fair comparison between electric utilities that own and generate power vs. utilities that contract for power.

In general, imputed debt is described in the 1994 update of S&P 1992 Corporate Finance Criteria:

To analyze the financial impact of purchased power, S&P employs the following financial methodology. The net present value of future annual capacity payments (discounted at 10%), multiplied by a "risk factor" (which in PSE's case is 30%) represents a potential debt equivalent—the off-balance sheet obligation that a utility incurs when it enters into a long-term purchase power contract.

PSE's IRP, and our screening of potential resource acquisitions, includes a cost of equity to neutralize the reduction in credit quality from imputed debt for all PPAs. As described previously, the debt rating agencies consider long-term take-or-pay and take-and-pay contracts equivalent to long-term debt; hence there is a cost associated with issuing equity to rebalance the company's debt/equity ratio. Imputed debt in the IRP is calculated using a similar methodology to that applied by S&P. The calculation begins with the determination of the fixed obligations that are equal to the actual demand payments, if so defined in the contract, or 50% of the expected total contract payments. This yearly fixed obligation is then multiplied by a risk factor. PSE's current contracts have a risk factor of 30%, a change that occurred in May 2004. Prior to this change, PSE contracts had risk factors between 15% and 40%. Imputed debt is the sum of the present value, using a 7.7% discount rate (the company's current average cost of long-term debt), and a mid-year cash flow convention of this risk-adjusted fixed obligation. The cost

of imputed debt is the return on the amount of equity that would be acquired to offset the level of imputed debt to maintain the Company's capital and interest coverage ratios.

Imputed Debt's Effect on Capital Structure

Figures F-2 and F-3 show that the financial ratios with imputed debt are eroding PSE's financial strength as measured by the credit rating agencies. Total capitalization is approximately equal to year-end 2006, but the percentage mix of debt and equity is as allowed in the January 2007 General Rate Case order from the WUTC.

**Figure F-2
Illustrative Base Case Excluding Imputed Debt**

Capital Component	Illustrative Amount	Capital Structure	Cost Rate	Pre-tax WACC	WACC	After-tax WACC
Short-term Debt	\$128,655	2.70%	6.66%	0.18%	0.18%	0.12%
Long-term Debt	\$2,287,200	48.00%	6.64%	3.19%	3.19%	2.07%
Trust Preferred	\$252,545	5.30%	8.54%	0.45%	0.45%	0.29%
Imputed Debt						
Common Equity	\$2,096,600	44.00%	10.40%	7.04%	4.58%	4.58%
Total	\$4,765,000	100.00%		10.86%	8.40%	7.06%

**Figure F-3
Illustrative Base Case Including Imputed Debt**

Capital Component	Illustrative Amount	Capital Structure	Cost Rate	Pre-tax WACC	WACC	After-tax WACC
Short-term Debt	\$128,655	2.48%	6.66%	0.17%	0.17%	0.11%
Long-term Debt	\$2,287,200	44.07%	6.64%	2.93%	2.93%	1.90%
Trust Preferred	\$252,545	4.87%	8.54%	0.42%	0.42%	0.27%
Imputed Debt	\$425,000	8.19%	7.70%	0.63%	0.63%	0.41%
Common Equity	\$2,096,600	40.40%	10.40%	6.46%	4.20%	4.20%
Total	\$5,190,000	100.00%		10.60%	8.35%	6.90%

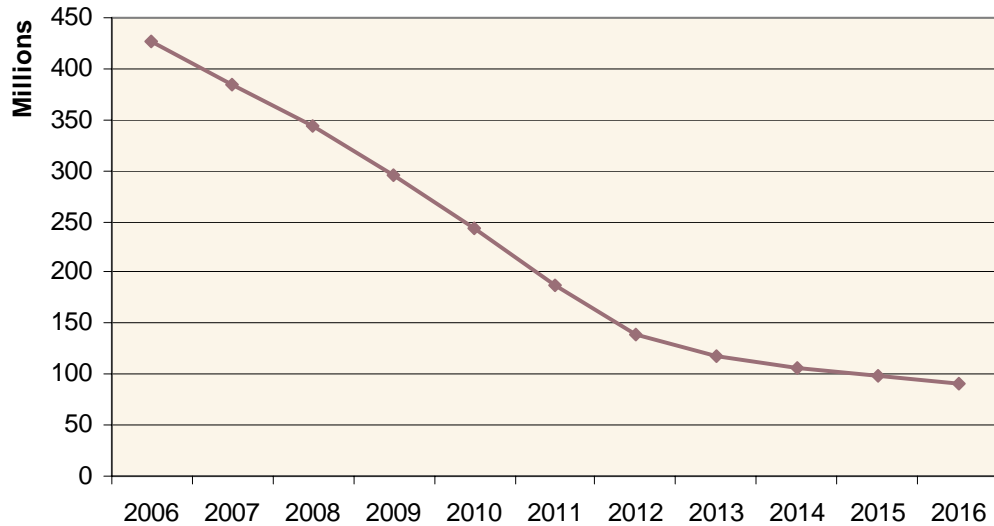
The pretax interest coverage ratio is reduced from over 2.7 to less than 2.5, and the ratio of debt to capital is increased from 57% to over 60%.

**Figure F-4
Financial Ratios With and Without Imputed Debt**

	No <u>Imputed Debt</u>	Includes <u>Imputed Debt</u>
Weighted Return on Equity	4.58%	4.20%
Tax impact	<u>/ 65%</u>	<u>/ 65%</u>
Pre-tax Weighted ROE	= 7.05%	= 6.46%
Cost of Debt	<u>+ 3.82%</u>	<u>+ 4.15%</u>
Pre-tax Cost of Capital	= 10.87%	= 10.61%
Cost of Debt	/ 3.82%	/ 4.15%
Pre-tax Interest Coverage	2.85 x	2.56 x
S&P Benchmark for "BBB" rating	2.4x - 3.5x	2.4x - 3.5x
Ratio Debt to Capital	56.0%	59.6%
S&P Benchmark for "BBB" rating	52% to 62%	52% to 62%

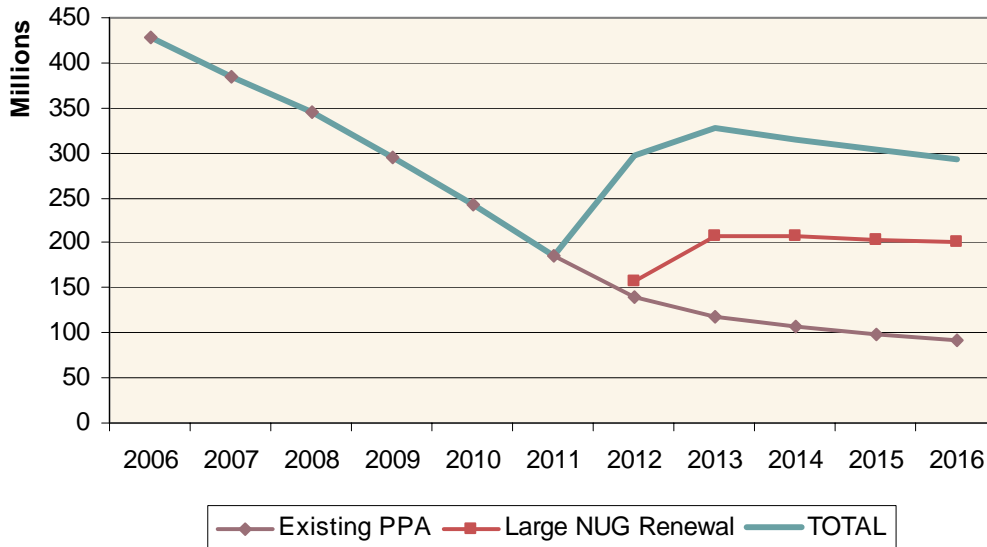
PSE has a number of PPAs outstanding, with termination dates from 2010 through 2037. In aggregate, these PPAs resulted in imputed debt of approximately \$425 million in 2006. Figure F-5 reflects existing contracts, including the 20-year PPA with Chelan County PUD that begins in 2011, but excludes imputed debt associated with possible renewal of a number of PPAs that expire between 2011 and 2019.

Figure F-5
Imputed Debt, Existing PPAs



PSE has several large contracts with four large nonutility generators (NUGs) in northwestern Washington that expire between 2011 and 2013. If we were to replace these expiring contracts with new 20-year contracts, priced at the Aurora forecast prices, the imputed debt could increase to about \$325 million in 2013. This is likely a low estimate, because prices for fixed-rate contracts generally have a forward premium and a credit premium that would increase contract payments. In addition, the estimate may also be low because it does not include imputed debt from possible contracts for power from renewable resources and possible power bridging agreements (PBAs) that may be used to partially fill the near-term resource need. Figure F-6 illustrates future imputed debt under these circumstances.

Exhibit F-6
Imputed Debt with Selected Contracts Replaced at Market Prices



B. Accounting Changes

Purchased Power and Lease Accounting

The Financial Accounting Standards Board (FASB) Emerging Issues Task Force (EITF) issued EITF 01-8 in 2001. EITF 01-8 gives criteria to determine whether an arrangement should be accounted for as a lease under FASB Statement 13, "Accounting for Leases." Power supply agreements in which PSE has the right to control the use of the underlying property, plant or equipment may be considered a lease for accounting purposes and will thus require lease accounting. Such right to control is to be assessed with respect to, among other things, the amount of power PSE may purchase from the generating facility; PSE's right to control access to the underlying property, plant, or equipment; and the relevant contract pricing structure. These determinations may lead to lease accounting under the agreements.

Derivative and Hedge Accounting

In June 1998, the FASB issued Statement 133 (FAS 133), “Accounting for Derivative Instruments and Hedging Activities,” which established accounting and reporting standards for derivative contracts and hedging activities. The purpose of FAS 133 is to improve the quality of financial reporting by requiring that contracts with comparable characteristics be accounted for similarly. FAS 133 has the potential to increase volatility of reported earnings due to the requirement to record the unrealized gains and losses from derivatives on a company’s books. In April 2003, the FASB issued Statement 149 (FAS 149), an amendment to FAS 133 that clarified the definition of derivatives and the implementation of this statement for financial instruments. If certain criteria are met as defined in FAS 133 or FAS 149, then PSE may be required to mark-to-market the agreement and record the mark-to-market effect either in the equity section of the balance sheet or in the income statement. Depending on the mark-to-market accounting, it may adversely impact PSE’s cost of equity and corporate credit rating, and the ultimate cost of the PPA to PSE customers.

Variable Interest Entities

In December 2003, the FASB issued a revision to Interpretation 46 (FIN 46), “Consolidation of Variable Interest Entities.” Consolidated financial statements are to include subsidiaries in which the enterprise has a controlling financial interest. That requirement has usually been applied to subsidiaries in which an enterprise has a majority voting interest, but in many circumstances the enterprise’s consolidated financial statements do not include variable interest entities with which it has similar relationships. The primary objective of FIN 46R is to provide guidance on the identification of and the financial reporting for entities over which control is achieved through means other than voting rights—such entities are known as variable interest entities. Depending on specified criteria, FIN 46 may require PSE to consolidate entities providing long-term PPAs. Such consolidation requires PPA suppliers to provide their detailed financial information to determine the applicability of FIN 46 and, if necessary, consolidation of their financial statements. Depending on the capital structure of the PPA supplier, the consolidation may adversely impact PSE’s corporate credit rating and the ultimate cost of the PPA to PSE customers.

C. Risk Management

Starting with the Western energy crisis, and continuing through the recent escalation in natural gas prices, energy markets have experienced substantial volatility.

Consequently, market participants have taken steps to improve their risk management. This includes taking a more structured approach to managing price exposure, and the use of better modeling tools. The market offers a variety of fixed-priced contracts and financial instruments to hedge a company's price risk exposure.

PSE balances numerous risk factors when obtaining energy resources to meet customer load. We must analyze these factors to (1) deliver reliable energy when our customers demand it, (2) serve our customers at a reasonably low cost while mitigating price volatility, and (3) enhance the value of PSE's energy resources to reduce power and gas costs. PSE uses risk management strategies to reduce volatility in power and gas costs, manage unused capacity, and increase the operational flexibility of assets.

A variety of hedging tools can reduce price volatility for power customers. We engage in forward market fixed-price purchases (both in physical gas and power purchase contracts and through financial market derivatives) to lock in gas prices, to purchase power as needed, and to acquire winter-peaking capacity hedges. In addition, our resources give us the flexibility to store hydroelectric energy where possible, to dispatch and displace generation as market conditions provide economic signals, and to use transmission to move energy from resources to load.

Several factors limit our strategic options. Market liquidity is one, as there may not be sellers of the hedge transactions we seek. Market conditions may also make certain products very expensive. For example, an option contract such as a call—which is the right, but not the obligation, to purchase energy at a predetermined price—might be a very attractive means to manage load variability risk. But in volatile markets, the cost might be prohibitive. Counterparty issues limit our options: We may not be able to obtain a range of financially strong counterparties to reduce the risk of default, and our own credit position can limit our ability to enter into hedging transactions.

With a higher credit rating, counterparties would extend us more open credit, thereby enabling us to expand our hedging capacity for the power and gas portfolios without incurring costs to post collateral and without increasing debt. This benefits customers, as the company gains increased hedging capacity, without additional credit costs. With a better credit rating, PSE anticipates counterparties would be willing to sell us more fixed-

price supply or other hedge transactions, thereby expanding our hedging capability. We would continue to link hedging strategies to price signals, fundamental analysis, and risk analysis; but when prices are opportunistic we believe it is important to have the capacity and flexibility to hedge more and further forward in time.

D. Tax Incentives

Production Tax Credit

In December 2006, the federal production tax credit (PTC) for wind and other renewable energy technologies was extended for one additional year – through December 31, 2008. The PTC provides a \$19 per megawatt-hour (MWh) or 1.9 cents per kilowatt-hour (kWh) tax credit for electricity generated over the first 10 years of a wind project’s operation.

The bill also extended the 30% solar energy investment tax credit (ITC) for homeowners and businesses for one additional year, through the end of 2008.

**Figure F-7
Production Tax Credits for Renewable Resources**

Resource	PTC Rate	Term	Comments
(1) Wind	\$19 / MWh	10 years	Extended through 12/31/2008 2006 Rate = \$19 / MWh = 1.2981 * 1.5 ¢ / kwh
(2) Closed-loop biomass	\$19 / MWh	10 years	
(3) Open-loop biomass	\$10 / MWh	10 years	\$10 = 50% * 1.5 * 1.2981
(4) Geothermal & Solar	\$19 / MWh	5 years	For Solar projects, the 30% investment tax credit provides more incentive than the \$19 / MWh PTC.
(5) Small irrigation power	\$10 / MWh	5 years	
(6) Landfill gas power	\$10 / MWh	5 years	
(7) Trash combustion facilities	\$10 / MWh	5 years	

Source:

Federal Register March 31, 2006.

<http://a257.g.akamaitech.net/7/257/2422/01jan20061800/edocket.access.gpo.gov/2006/pdf/E6-4668.pdf>

PTCs add significantly to the economics of wind projects. The 2006 level of \$19/MWh is equivalent to a customer rate, or revenue requirement, benefit to PSE customer payments of about \$29/MWh in the first of year. The PTC rate escalates with inflation over time but only applies to the first 10 years of generation. With escalation and the 10-year term, the 20-year levelized reduction in customers' revenue requirement is about \$23 / MWh. The following table illustrates the calculation for a hypothetical project producing 1 MWh:

Figure F-8
Application of Production Tax Credits to a Hypothetical Project

		MWh	PTC	Revenue Required
	1/1/2006	-	0	0
1	2006	1	\$ 19.00 ¹	29.23
2	2007	1	\$ 20.00	30.77
3	2008	1	\$ 20.00	30.77
4	2009	1	\$ 21.00	32.31
5	2010	1	\$ 21.00	32.31
6	2011	1	\$ 22.00	33.85
7	2012	1	\$ 23.00	35.38
8	2013	1	\$ 23.00	35.38
9	2014	1	\$ 24.00	36.92
10	2015	1	\$ 24.00	36.92
11	2016	1	\$ -	\$ -
12	2017	1	\$ -	\$ -
13	2018	1	\$ -	\$ -
14	2019	1	\$ -	\$ -
15	2020	1	\$ -	\$ -
16	2021	1	\$ -	\$ -
17	2022	1	\$ -	\$ -
18	2023	1	\$ -	\$ -
19	2024	1	\$ -	\$ -
20	2025	1	\$ -	\$ -
8.4%	NPV	8.79		\$ 199.43
	Levelized			\$ 22.68

¹ 2006 Rate = \$19 / MWh = 1.2981 * 1.5 ¢ / kwh. Future rates assume escalation of 2.5% per year. All PTC rates are rounded to the closest \$1 / MWh or 0.1 ¢ / kwh.

Clean Coal Tax Incentives

The Energy Policy Act of 2005 created two ITCs for integrated coal gasification combined cycle (IGCC) and advanced combustion facilities. IGCC projects may receive a 20% credit, capped at \$800 million. Other advanced coal-based projects may receive a 15% credit, capped at \$500 million. The credits are available only to projects certified by the Secretary of Treasury, in consultation with the Secretary of Energy. In addition, the EAct creates a 20% ITC for certified industrial gasification projects. The total amount of gasification credits allocable is limited to \$350 million. A good summary of different elements of the EAct affecting coal projects can be found at <http://www.coal.org/PDFs/KeyCoalIncentives0705.pdf>.

These three different tax incentives combine to total \$1.65 billion of tax credits. The projects must be certified by the Secretary of Energy, before receiving credits. On November 30, 2006, the U.S. Department of Energy and the Internal Revenue Service allocated about \$1 billion of tax credits for nine projects: three utility IGCC projects (totaling \$400 million), two utility advanced coal projects (totaling \$250 million), two industrial gasification projects, and two others that were not identified. The balance of about \$650 million will be available for allocation in 2007. The 2007 application period closes on October 1, 2007. Energy Northwest applied for \$107 million in tax credits for proposed private owners of their Pacific Mountain Energy Center (Kalama) project and was not mentioned as being selected.

Since the clean coal credits are expected to be used projects currently under development, this IRP assumed that tax credits would not be available to PSE for lowering the cost of IGCC plants.

PSE's Tax Credit Appetite

PSE's use of tax credits is limited by tax law to a maximum of 25% of what the Company would have otherwise paid; it is further limited because resulting current taxes cannot be reduced below the level of tax calculated via the alternative minimum tax methodology. Based on PSE's federal tax payments in 2003–2005, the appetite for tax credits for these years ranged from \$17 million to over \$21 million. The PTC expected in 2007 from the Hopkins Ridge and Wild Horse wind projects is about \$21 million. Thus, under PSE's current taxable income, our two existing wind projects have filled our appetite for tax credits.

Even though the tax credit appetite is filled at this time, we have several alternatives to capture these incentive benefits.

- First, renewable energy received through PPAs should reflect the PTC in the PPA pricing.
- Second, as our earnings grow through time, additional tax credit appetite will arise and could be used to develop small renewable projects.
- Third, the PTC rules contain provisions for rolling forward the benefit 20 years if it cannot be used in the current year. This alternative approach would likely be considered for a smaller project with limited PTCs that may be able to be used by PSE in good earnings years. If benefits were passed through to customers when power is generated, then customer costs would increase by the carrying cost on the unused credit account.
- Fourth, the financial markets have developed hybrid financings that use tax equity investors who are able to use the tax credits. These hybrid financing structures were developed for government-owned utilities that pay no federal tax. We have investigated several hybrid structures and will continue to pursue those that make economic sense for our customers.