Project	**Rate-regulated activities**
Topic	**Illustrative examples on presentation and disclosures**

Introduction

Objective of this paper

1. The objective of this paper is to provide illustrative examples of the presentation in the financial statements as well as the additional disclosures that the staff recommend should be required in the notes to the financial statements. The examples are intended to assist the Board to reach decisions on those recommendations.

2. The staff has included in Appendix A extracts from the presentation and disclosures of published financial statements of the following entities:

   (a) one Canadian company: Gaz Métro (Appendix A - Example 1), and

   (b) two US companies: Xcel Energy and Puget Energy(Appendix A - Examples 2 and 3).

   We had intended also to include information from a Brazilian company filing its financial statements in the US: Cemig, but we could not reproduce the information in a legible format in this paper. Its financial statements and additional examples are available from the staff on request.

Background

3. The Board had a preliminary discussion of the presentation and disclosure requirements at its meeting in April 2009 but did not have sufficient time to reach conclusions. For ease of reference, in paragraphs 4 to 8 the staff has reproduced the general presentation and disclosure principles and disclosure requirements that were recommended in Agenda Paper 9B for the meeting in April.

General principles

4. In accordance with the Board's general approach to presentation and disclosure, the staff recommends that the standard include the following general principles:

> 1. An entity shall disclose information that enables users of its financial statements to understand the nature and economic effects of rate regulation on its financial statements.
>
> 2. An entity shall disclose information that identifies and explains the amounts recognised in its financial statements arising from rate regulation.

Disclosure requirements

5. Rate regulation can affect both the revenue-generating ability of an entity and the periods in which its revenues are recognised. It is, therefore, an important consideration in evaluating the financial performance of entities with rate-regulated operations.

Minimum disclosures for general principle 1 in paragraph 4

6. Paragraph 4 proposes that entities subject to rate regulation should disclose general information facilitating an understanding of the nature and economic effects of rate regulation. The staff believes that the following disclosures should be specified as the minimum necessary to achieve that principle:

    (a) the fact that the entity is subject to rate regulation, and a description of the nature and extent of the rate-regulated operations; and

    (b) for each set of operations subject to a different rate-setting authority:

        (i) the identity of the rate-setting authority and, if it meets the definition of a related party (see IAS 24 *Related Party Disclosures*), a statement to this effect, together with an explanation of why this is the case; and

        (ii) the process by which the entity's rates are approved, as well as information providing a basic understanding of how it has been applied including the allowed rate of return.

7. The staff believes that the following information should be disclosed in accordance with requirements that already exist in IAS 1 (paragraphs 122 and 125). However, for greater certainty, we believe it would be useful to specify the required information in this standard:

(a) the indicators management considered in reaching its conclusion that its activities are within the scope of the standard, when that determination requires significant management judgement (see Agenda Paper 9C from the April 2009 meeting). (IAS 1.122)

(b) information about how the entity estimates regulatory assets and liabilities, either:

  (i) the supporting regulatory action, for example, issuance of a final rate order or approval to accumulate amounts pending final disposition at a later date (the date being disclosed, when known), or

  (ii) the expectations of the entity regarding future regulatory actions. (IAS 1.125)

(c) a description of the regulatory risks and uncertainties affecting the eventual recovery of the assets or settlement of the liabilities and their timing. (IAS 1.125)

Minimum disclosures for general principle 2 in paragraph 4

8. Paragraph 4 proposes that entities subject to rate regulation should disclose information that identifies and explains the amounts recognised in their financial statements arising from rate regulation. The staff believes that the following disclosures should be specified as the minimum necessary to achieve that principle:

(a) for each category of item and if appropriate by classes, how it has been reflected in the financial statements and:

  (i) the carrying amount of the asset or liability in the statement of financial position;

  (ii) the income statement effect of such recognition for the period;

  (iii) the remaining period over which the carrying amount of the asset is expected to be recovered or the liability is expected to be settled;

(b) costs being amortised in accordance with the actions of a regulator, but which are not being allowed to earn a return during the recovery period as well as the remaining amounts being amortised and the remaining recovery period;

(c) when accounting for the effects of rate regulation has been discontinued since the last financial statements issued, a statement to that effect together with the reasons for the discontinuance and identification of the rate-regulated operations affected.

Staff analysis

Use of a tabular format

9. For most companies already recognising regulatory assets and liabilities in accordance with FAS 71 or GAAPs that are close to FAS 71, the staff notes that virtually all the information the staff recommends be disclosed is currently provided. However, as the Board will note from the examples, it is often available in various places throughout the financial statements in a way that can make things difficult to read and to connect.

10. In order to meet the minimum disclosure requirements proposed in paragraph 8(a), the staff thinks that entities should provide a table showing a reconciliation of the carrying amount of the various categories of regulatory items in the statement of financial position from one period end to the next. This reconciliation would show the movements in the accounts as a result of amounts recognised in the statement of comprehensive income. In the staff's view, such a table would be extremely useful in helping users to understand how the entity's reported financial results and position have been affected by rate regulation.

11. Paragraph 12 provides an example of such a table. Its main purposes are to gather all the relevant information into one note in the financial statements and to show the effect of rate-regulation that has been recognised in the financial statements. We would expect that entities would provide additional descriptive disclosure following the table, in the same way many entities currently do as illustrated by the examples in the Appendix.

12. The table below illustrates the format the staff recommends should be required and gives examples of the categories of regulatory assets and liabilities we expect would be disclosed in accordance with the recommendation in paragraph 8(a).

All amounts in CU		**Years over which recovery or settlement is expected**	**Opening balance**	**Recovered/ repaid in current period**	**Current period amount to be recovered/repaid in future periods**	**Closing balance**
Regulatory assets						
Pension and other post-retirement benefits						
Power cost adjustment (balancing accounts)						
Environmental remediation						
TOTAL			**(a)**	**(b)**	**(c)**	**(d)**
Regulatory liabilities						
Power cost adjustment (balancing accounts)						
Transmission and delivery storm reserve						
Deferred gain on property sales						
TOTAL			**(a)**	**(b)**	**(c)**	**(d)**

(a) Total regulatory assets/liabilities reported on the face of the statement of financial position at the end of the previous period.

(b) Prior period amounts included in the determination of current period rates. The totals are the effect on current period revenue and expense.

(c) Current period amounts that would otherwise have been recognised in the statement of comprehensive income to be recovered from/repaid to customers in future periods. The totals are the effect on current period expenses.

(d) Total regulatory assets/liabilities reported on the face of the statement of financial position at the end of the current period.

13. The staff is also of the view that it could be useful to users if entities identified the line items in the statement of comprehensive income that were affected. This information could be provided in the table or in the other disclosure. The staff expects that for many of the items, this would be obvious from the name of the category.

Illustrative example of the proposed table above

14. For the purpose of illustrating the proposed table, the staff has put information provided by Gaz Métro (Appendix A – Example 1) for one specific line item into this format.

	Years over which recovery is expected	**Opening balance 2007**	**Amortisation (recovered in current rates)**	**Current period amount to be recovered in future rates**	**Closing balance 2008**
Rate stabilisation account relating to temperature and wind velocity Note 4(a)	2009 - 2014	54,633	(7,130)	14,427	61,930

Recommendation and question 1 – Minimum disclosures
The staff recommends that the disclosures set out in paragraphs 5-8 should be required as the minimum necessary to achieve the principles in paragraph 4. Does the Board agree? What, if any, additional disclosures does the Board believe should be required?

Question 2 – Format of disclosures
For the reasons set out in paragraphs 9-11, the staff recommends that the tabular reconciliation illustrated in paragraphs 12 and 14 be required. Does the Board agree?

Appendix A

A1. The staff has included extracts from the presentation and disclosures of published financial statements of the following entities:

(a) one Canadian company: Gaz Métro (Example 1), and

(b) two US companies: Xcel Energy and Puget Energy (Examples 2 and 3).

A2. The extracts selected for each company are intended to illustrate particular aspects of disclosure that are important in different situations. The staff also thinks that the Board should be aware of the extensive disclosure about the nature and effect of rate regulation such entities already provide.

A3. However, the staff emphasises that we are not making any assessment of whether the extracts we have reproduced comply with the standards or other requirements of any jurisdiction.

Example 1: Gaz Métro – extract from consolidated financial report for the year ending on 30 September 2008

1. NATURE OF OPERATIONS

Gaz Métro Limited Partnership (the Partnership or Gaz Métro) is a company whose core business is the distribution of natural gas in Quebec. Gaz Métro is also, indirectly, the sole shareholder of Vermont Gas Systems, Inc. (VGS), the sole gas distributor in Vermont (U.S.A.), and since April 12, 2007, of Green Mountain Power Corporation (GMP), the second largest electricity distributor in Vermont. In addition, through its subsidiaries, joint ventures and companies subject to significant influence, Gaz Métro is involved in other mostly regulated activities relating to the transportation and storage of natural gas as well as energy and other services.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

REGULATION

Gaz Métro's core business is the distribution of natural gas by pipeline in Quebec, an activity that is regulated by the Régie de l'énergie (the Régie).

Also, through certain subsidiaries, joint ventures and companies subject to significant influence, it carries on other activities that are regulated by other bodies. Trans Québec & Maritimes Pipeline Inc. (TQM) and Champion Pipe Line Corporation Limited (Champion) are regulated by the National Energy Board (NEB). Portland Natural Gas Transmission System (PNGTS) is regulated by the Federal Energy Regulatory Commission (FERC), and VGS and GMP are regulated by the Vermont Public Service Board (VPSB).

In exercising their authority, the regulatory bodies render decisions on, among other things, system development, rate setting and the utilization of certain underlying accounting policies that are different from those otherwise applied by non-regulated enterprises. The impacts of rate regulation on the Partnership, including the carrying amount of regulatory assets and liabilities, are presented in Note 4.

DEFERRED CHARGES

Deferred charges comprise essentially costs to be recovered in future rates of which, a portion is subject to regulatory treatment.

Certain charges are deferred and then recovered in rates over various periods not exceeding 30 years depending on the nature of these charges (see Note 4).

Deferred charges related to the Development of information technology are intangible assets subject to amortization and include costs incurred by the Partnership for information system development and the cost of software and licences acquired. The Partnership amortizes these costs on a straight-line basis over the estimated useful life of each asset, which ranges from five to ten years.

Other deferred charges consist of numerous items of lesser monetary value and are amortized on a straight line basis over a weighted average period of seven years.

4. RATE REGULATION

APPROVAL OF RATES

The Partnership operates in various regulated sectors where the cost of energy and providing services are recovered in rates charged to customers. The following information presents the Partnership's main regulated enterprises and the impact of regulations on the resulting accounting treatment.

ESTABLISHMENTS REGULATED IN QUEBEC

Quebec distribution activity

The activities of the Quebec natural gas distribution activity are regulated by the Act respecting the Régie de l'énergie. Rates are established primarily on a cost of service-based method, which allows the Partnership to set its revenues each year so as to recover the expenditures it expects to incur to serve its clientele and earn a reasonable base return on deemed Partners' equity allocated to this activity. In addition, an incentive return can be earned for improving financial performance. The incentive return stems from a performance incentive mechanism that was implemented in October 2000, subsequently modified and that will expire in September 2012.

For regulatory purposes, cost of service includes deemed income and capital taxes. These deemed income and other taxes are computed as though Gaz Métro was a taxable Canadian corporation, notwithstanding the tax status and the tax rate of the Partners.

The Régie has established that the rate of return on the rate base is to be fixed using a "deemed" capital structure, in which Partners' deemed equity is in the order of 46.0%, including 38.5% that is compensated as if it were common shares and 7.5% as if it were preferred shares.

The authorized base rates of return are determined using a formula approved by the Régie. For the year ending September 30, 2008, they are 9.05% on Partners' deemed common share equity and 5.38% on deemed preferred share equity compared to 8.73% and 5.45% respectively, the preceding year. An incentive return of 0.47% has also been authorized on Partners' deemed common share equity based on anticipated productivity gains for the fiscal year compared to 0.84% the preceding year.

With respect to supply service, i.e. supplying natural gas, the Act respecting the Régie de l'énergie states that the distributor shall sell natural gas at its actual purchase cost.

ESTABLISHMENTS REGULATED ELSEWHERE IN CANADA

TQM and Champion

The main activity of TQM, in which Gaz Métro owns a 50.0% interest, and Champion, which is wholly-owned by Gaz Métro, is the transportation of natural gas. Their main activities are regulated by the NEB, an independent federal organization that regulates the international and inter-provincial aspects of the petroleum, natural gas and electricity industries with respect to revenue determination, tolls, construction and operations.

This organization approves the tolls based on the annual cost of service, which includes a specified annual return on capital, as well as operations expenses, taxes and amortization. A toll schedule based on the estimated cost of service is applied for the current year and the differences between estimated and actual cost of service are included in the tolls for the following year.

The current rate of return on equity is based on the rate of return formula approved by the NEB and adopted during hearing RH-2-94 on the cost of capital of a number of pipeline companies. The deemed equity ratio is 30.0% of the rate base in the case of TQM and 46.0% in the case of Champion. TQM's authorized return is 8.71% for its fiscal year ending December 31, 2008 compared to 8.46% for the preceding year. On December 17, 2007, TQM filed a cost of capital application with the NEB for the years 2007 and 2008. The application requests the approval of an 11.0% return on 40.0% deemed common equity. TQM will maintain its current tolls until a final decision is announced. For Champion, the authorized return on equity is 9.05% for its fiscal year ending September 30, 2008, compared to 8.73% for the preceding year.

ESTABLISHMENTS REGULATED IN UNITED STATES

VGS and GMP

VGS and GMP, two indirectly wholly-owned subsidiaries of Gaz Métro, are regulated by the VPSB. Their rates are established using a cost of service-based method, which enables them to fix their revenues so as to recover the expenditures they expect to incur to serve their clientele and earn a reasonable base return on deemed shareholder's equity. Deemed shareholder's equity was 55.0% of the rate base for the 2008 and 2007 fiscal years for VGS and 52.2% and 52.8% in 2008 and 2007 respectively for GMP. The allowed base rate of return on equity, which is fixed by the VPSB, has been 10.50% since October 1, 2006 for VGS and is 10.21% for GMP since January 1, 2008, compared with 10.25% from January 1 to December 31, 2007.

A rate agreement was approved by the VPSB on September 21, 2006 and came into force on October 1 of that year. It includes a quarterly natural gas price adjustment formula for VGS and the ability to submit an annual rate application for the other items, excluding gas costs. GMP has a similar quarterly adjustment mechanism for the price of electricity and an annual rate for other items since February 1, 2007.

PNGTS

PNGTS, in which Gaz Métro owns a 38.3% indirect interest, operates a gas pipeline in the northeastern United States. It is regulated by the FERC in accordance with the terms and conditions of the Natural Gas Act for the regulation of natural gas transportation tolls.

The objective of the FERC regulations is to ensure the proper recovery of expenditures in rates that also include a reasonable base return on Partners' equity. On April 1, 2008, PNGTS filed a general rate case under Section 4 of the Natural Gas Act. A decision has not yet been rendered. The hearings are scheduled to begin on March 10, 2009.

IMPACT OF RATE REGULATION ON CONSOLIDATED FINANCIAL STATEMENTS

To reflect current or expected regulatory body measures, the accounting policies adopted by the Partnership may differ from the policies that would normally be adopted by a non-regulated enterprise. Set out below is a description of these differences and their impacts on the financial statements.

REVENUE RECOGNITION

The accounting policies are described under Revenue Recognition in Note 2 and the impacts of these policies are described under Regulatory Assets and Liabilities of this note.

PROPERTY, PLANT AND EQUIPMENT AND AMORTIZATION

The impact of rate regulation on the accounting treatment of these assets is described under Property, plant and equipment in Note 2.

If the accounting standards for entities subject to rate regulation were not used, the capitalized equity component of the return for certain construction projects, the corresponding income and the subsequent amortization of these items would not be recognized.

Realized gains and losses on the disposal of retired properties are, as prescribed by present regulations, recorded mainly as adjustments of accumulated amortization related to property, plant and equipment instead of being included directly in income.

In the absence of regulatory accounting for entities subject to rate regulation, the costs of retiring property, plant and equipment that are capable of being estimated would result in liabilities in the balance sheet. The offset would be recorded as an increase in the costs of property, plant and equipment. The Partnership records these liabilities as an increase of accumulated amortization as the amortization expense, which includes a retirement cost component, is recorded.

The Partnership is unable to make a reasonable estimate of the monetary impact of these practices on the value of property, plant and equipment, amortization expense or other components of the financial statements.

EMPLOYEE FUTURE BENEFITS

The Quebec distribution activity expenses the costs of pension benefits and other post-employment benefits when they are disbursed in accordance with the method of recovering costs in rates. Further details about the impact of rate regulation on the accounting treatment of these items are provided under Employee future benefits in Notes 2 and 17 and under Regulatory assets and liabilities of this note.

In the absence of regulatory accounting for entities subject to rate regulation, the cost of defined pension plan benefits and other post-employment benefits would be determined by a projected benefit method prorated according to eligible years of service and expensed as the services would be rendered by the employees. If this practice had been adopted, an additional pension plan and other post-employment benefit liability of $13,605,000 and $9,608,000 would have been presented in the balance sheet as at September 30, 2008 and 2007, and the costs recorded would have been $5,132,000 and $3,979,000 higher in 2008 and 2007 respectively. However, these costs would have been included in the rate application so as to recover such amount from customers, thereby eliminating the impact on income.

INCOME TAXES

For its income from its regulated activities, the Partnership has elected to record income taxes on the taxes payable method as described in Handbook Section 3465. Future income tax assets and liabilities relating to differences between the tax value and the carrying amount of assets and liabilities are not recorded because it is expected that future income taxes will be included in rates approved by Canadian regulatory bodies and billed to customers in future rates. In the absence of regulatory accounting for enterprises subject to rate regulation, the Partnership would have used the tax liability method. Under this method, future income tax assets and liabilities are recognized as described above. The future income tax assets and liabilities are measured using enacted or substantively enacted tax rates and laws at the date of the financial statements for the years in which the temporary differences are expected to reverse. As at September 30, 2008, adoption of the tax liability method would have led to recognition of an additional future income tax liability on the balance sheet of $92,516,000 compared to $107,646,000 as at September 30, 2007.

ACQUISITION OF A SUBSIDIARY

In connection with the acquisition of GMP on April 12, 2007, the Partnership used the carrying amount of assets acquired and liabilities assumed in the purchase price allocation and attributed the full amount of the excess purchase price to goodwill. Under regulated accounting, assets included in the rate base yield a return through cash flows. Since these future cash flows are regulated, the fair value of assets is equivalent to their cost. If the accounting standards for entities subject to rate regulation were not applied, the purchase price allocation would have differed, since the Partnership would have remeasured the assets and liabilities at their fair value. It is not possible to reasonably determine the monetary impact of these practices on the purchase price allocation, value of intangible assets or other accounts.

ALLOWANCE FOR VACATION

The Partnership recognizes the cost of vacation granted to employees in income when such costs are disbursed, in accordance with the recovery of costs through rates.

If the accounting standards for entities subject to rate regulation were not applied, the Partnership should use accrual accounting to recognize vacation payable. If the Partnership had applied this practice, it would have recognized a liability equal to the amount of vacation payable as at September 30, 2008, i.e. $7,352,000. The allowance would have been $7,135,000 as at September 30, 2007 and the impact on 2008 fiscal year income would be the difference between the allowance for the 2008 and the 2007 fiscal years.

REGULATORY ASSETS AND LIABILITIES

Regulatory assets represent the costs the Partnership expects to recover from its customers in future years through the rate setting process, as approved by the various regulatory bodies. Regulatory liabilities represent revenues the Partnership expects to return to its customers in future years through the rate setting process.

Regulatory assets and liabilities would not be recorded in the same manner if rates were not regulated. They arise from amounts that were not considered in the initial annual rate application, or that represent actual differences in revenues or costs from estimates initially presented when the application was filed. In accordance with the present regulatory framework, interest is generally accumulated on the regulatory asset and liability account balances, which will be recovered or returned through rates charged to customers in the future.

Regulatory assets are included in the balance sheet under Deferred charges (see Note 9) and regulatory liabilities are included under Accounts payable and accrued liabilities and Deferred credits (see Note 13).

The following table presents the net carrying amount of the regulatory assets and liabilities as at September 30, 2008 and 2007:

	Years recovery or settlement expected		2008		2007
REGULATORY ASSETS (LIABILITIES)					
Rate stabilization account related to temperature and wind velocity (a)	2009-2014	$	**61,930**	$	54,633
Rate stabilization account related to inventory variances (a)	2009-2010	$	**1,429**	$	8,826
Expenses (credits) related to energy costs (b)	2009	$	**20,348**	$	(33,064)
Grants paid (c)	2009-2018	$	**105,821**	$	106,834
Expenses related to financial instruments (d)	2009-2016	$	**32,930**	$	74,620
Expenses related to Global Energy Efficiency Plan (e)	2009-2010	$	**5,259**	$	7,261
Expenses related to pension plan funding (f)	2009-2022	$	**20,092**	$	13,303
Expenses related to Green Fund duty (g)	2009-2010	$	**14,106**	$	-
Customers' share of overearnings (h)	2009-2010	$	**(18,756)**	$	(22,715)
Reserve related to Energy Efficiency Fund (h)	2009-2012	$	**(17,254)**	$	(17,305)
Financing expenses (i)	2009-2038	$	**8,767**	$	9,604

(a) To alleviate the unpredictable and uncontrollable impacts of certain events on its activities, the Régie has authorized the Quebec distribution activity to use various rate stabilization accounts. The unpredictable impacts for which the Régie authorizes stabilization accounts include mainly the impact of temperature fluctuations and, since October 1, 2007, wind velocities on revenues, as well as the impact on income of natural gas inventory variances during the year. The annual variations are amortized so as to be recovered or returned in rates starting in the second subsequent year over periods of five years for temperature and wind and over one year for inventory variances.

A net amount of $14,427,000 to be recovered from customers was recorded in the rate stabilization accounts for temperature (warmer than normal) and wind velocity (stronger than normal) variations during the year, compared with a net amount of $21,253,000 solely for temperature (warmer than normal) variations during the previous year. As mentioned previously, during the 2007 fiscal year, revenue normalization by the Quebec distribution activity did not take account of the wind factor, which therefore directly affected the Sector's profitability.The amortization expense of the rate stabilization account related to temperature and wind velocity amounts to $7,130,000 in 2008 and $8,254,000 in 2007.

Adjustments for inventory variances totalling $1,504,000 in 2008 and $579,000 in 2007 have been deferred to the 2010 and 2009 fiscal years respectively instead of being expensed immediately in income under Direct costs. The amortization expense of the rate stabilization account related to inventory variances amounts to $8,901,000 during the 2008 fiscal year, whereas no amount was recorded for the 2007 fiscal year.

In the absence of regulatory accounting for entities subject to rate regulation, income for the 2008 fiscal year would have been affected by the utilization of a different approach for establishing rates. The impacts of a different approach are impossible to determine a priori.

(b) The impact of rate regulation on the accounting treatment of these assets is described under Inventories in Note 2. The expenses (credits) related to energy costs (natural gas and electricity), are composed of offsets related to inventory revaluations and other adjustments to the cost of energy distributed that are necessary to eliminate the impacts from the sale of the commodity on income, as prescribed by the Régie and the VPSB. These amounts are then returned to or recovered from customers in the form of a rate adjustment, over a period of three months for electricity and over a period of 12 months for natural gas. In the absence of regulatory accounting for this situation, a customer account receivable or account payable would have been recorded in the balance sheet in place of the deferred charges or credits because these costs are, by law, fully borne by customers who must ultimately pay for the costs incurred. In substance, these accounts only represent differences in billings to customers that are corrected within a period of three months for electricity and within a period of 12 months for natural gas.

(c) Grants paid are mainly amounts given to customers to convert their equipment so they can sign a service contract with Gaz Métro. These amounts are deferred and then amortized over the periods covered by the contracts (generally five years) or longer (ten years) when the customers in question do not have the flexibility to switch to an alternative energy without making a substantial investment. Under the Partnership's regulatory accounting, amortization commences in the year following the inception of the contract. In the absence of regulatory accounting, the amortization period for grants would have been matched to the periods covered by the underlying service contracts, generally five years, and amortization would have commenced at the inception of the contract. In light of these differences, an additional amortization of deferred charges of $6,656,000 in 2008 and $7,270,000 in 2007 would have been recorded and included in the rate application.

(d) The expenses related to financial instruments represent the net impacts of remeasurements of the derivative financial instruments related to the distribution utilities. These financial instruments mature over eight years. Since October 1, 2006, derivative financial instruments have to be presented in the balance sheet and remeasured at their fair value. In the absence of regulatory accounting for entities subject to rate regulation, the offset of these remeasurements, which is presently included in deferred charges, should be recorded directly in income. If regulatory treatment had not been applied, the Partnership would have modified its hedge strategies so that the change in fair value of the financial instruments related to businesses in this sector, which amount to $41,690,000 and $3,162,000 during the 2008 and 2007 fiscal years respectively, would not affect results. It is therefore impossible to determine what the impact would have been on results.

(e) The deferred charges related to the Global Energy Efficiency Plan are composed of the differences between the actual net impact on income and the amount projected at the beginning of the year in the rate application. These amounts are deferred and then completely amortized in the second fiscal year following the year they were incurred. If regulatory treatment had not been applied, these differences would have been included in income when incurred and no amortization expense would have been recorded. In the absence of regulatory accounting, income before income taxes would have been $2,002,000 higher in 2008 and $622,000 lower in 2007.

(f) VGS and GMP record unamortized net actuarial losses, unamortized past service costs and the remaining transitional obligation as a regulatory asset reflective of the recovery mechanism for pension and other post-employment benefits costs in the utility's jurisdiction. In the absence of regulatory accounting, the regulatory asset would have been reduced by $5,770,000 and the accrued benefit liabilities would have been reduced by the same amount, with no impact on income. The residual balance would have affected the GMP purchase price allocation. As previously explained, the Partnership is not able to determine what the impact would have been on the purchase price allocation.

(g) Since October 1, 2007, the Partnership is subject to the annual Green Fund duty. Deferred charges related to the Green Fund duty comprise two components. The first is the Green Fund duty for the first quarter of the 2008 year which has not been charged to customers of $13,271,000. This amount will be amortized over the next twelve months to be recovered in rates. The second component is the difference between the Green Fund duty paid during the 2008 year and the amount recovered from customers based on their actual consumption during this period. The $835,000 difference has been deferred and will be amortized to be recovered in rates during the 2010 fiscal year.

If regulatory treatment had not been applied, these differences would have been included in income when incurred and no amortization expense would have been recorded.

(h) The customers' share of overearnings is composed of amounts relating to the Quebec distribution activity and GMP. Additional information about the Quebec distribution activity's performance incentive mechanism is provided in Note 16. Under that mechanism, the Régie requires the customers' share of the overearnings to be returned to them, primarily in the form of rate reductions in the year following the approval of such overearnings. Part of the customers' share of the overearnings is also transferred to a fund for energy efficiency projects. Customers' share of GMP's excess return is returned to them in the form of a rate reduction over 12 months after the excess is approved by the VPSB. These liabilities are recorded in the years they arise.

(i) Financing expenses are transaction costs relating to long-term debt related to regulated operations. They are amortized on a straight-line basis in accordance with regulatory requirements. If regulatory treatment had not been applied, these transaction costs would have been applied against long-term debt and amortized using the effective interest method. Deferred charges and long-term debt would have been reduced by $8,767,000 and $9,604,000 as at September 30, 2008 and 2007 respectively. The impact of using a different expensing method is negligible.

RISKS AND UNCERTAINTIES

The risks and uncertainties related to the aforementioned regulatory assets and liabilities are periodically monitored and assessed. If the Partnership considered that certain amounts would probably not be recovered or returned through future rate adjustments, following interventions by the Régie or the VPSB, the value of the underlying asset or liability would be adjusted accordingly.

9. DEFERRED CHARGES

	2008	2007
Rate stabilization account related to temperature and wind velocity(a), (c)	$ 61,930	$ 54,633
Rate stabilization account related to inventory variances (a), (c)	1,429	8,826
Expenses related to energy costs (a), (c)	20,348	-
Grants paid (a), (c)	105,821	106,834
Expenses related to financial instruments (Note 22) (a)	32,930	74,620
Expenses related to Global Energy Efficiency Plan (a), (c)	5,259	7,261
Expenses related to pension plan funding (a)	20,092	13,303
Expenses related to Green Fund duty (a)	14,106	-
Financing expenses (a), (c)	8,767	9,604
Development of information technology (b), (c)	46,266	52,902
Other (c)	24,232	12,395
	$ 341,180	$ 340,378

(a) The impact of rate regulations on the accounting treatment of these assets is described in Note 4.

(b) As at September 30, 2008, the costs and accumulated amortization of deferred charges for development of information technology are $100,263,000 and $53,997,000 compared with $99,088,000 and $46,186,000 in 2007. During the 2008 year, the Partnership capitalized $5,541,000 in information technology development costs compared to $4,788,000 in 2007.

(c) Amortization of deferred charges including development of information technology is $46,636,000 in 2008 and $42,387,000 in 2007 and the amortization of financing expenses included in interest on long-term debt is $3,870,000 in 2008 and $4,338,000 in 2007. The reduction in deferred charges related to energy costs, including natural gas supply, transportation and storage, is $70,994,000 in 2008 and $57,980,000 in 2007.

13. DEFERRED CREDITS

	2008	2007
Credits related to energy costs (a)	$ -	$ 33,064
Customers' share of overearnings (a)	18,756	22,715
Gain on transfer (Note 10(a))	2,056	4,096
	$ 20,812	$ 59,875

(a) The impact of rate regulation on the accounting treatment of these liabilities is described in Note 4.

16. RESULTS AND BALANCE SHEET

The incentive return is $13,175,000 for the Quebec natural gas distribution activity in 2008 compared to $11,537,000 in 2007 and includes for the current year:

- Productivity gains of $4,839,000 included in authorized rate of return;
- Gaz Métro's $4,336,000 share in the return in excess of the return authorized by the Régie of $17,449,000; and
- The performance incentive related to the achievement of the Global Energy Efficiency Plan (GEEP) of $4,000,000.

In accordance with the sharing arrangement established in Decision D-2007-47 with respect to the performance incentive mechanism, Gaz Métro included all of these incentive return components in its income for the year. This incentive return is subject to the final approval of the Régie based on its review of the regulatory report that should be submitted in December 2008. Of the $13,113,000 overearnings balance, $11,618,000 was included in Deferred credits and will be returned to customers in the form of a rate reduction in the 2010 fiscal year, and $1,495,000 was contributed to the Energy Efficiency Fund.

Following the review of the regulatory report for the fiscal year ended September 30, 2007, the Régie approved, in December 2007, the overearnings calculation of $12,915,000 and authorized Gaz Métro to retain its $3,229,000 share as a performance incentive, which was included in income for the 2007 year. Of the $9,686,000 overearnings, $7,418,000 has been included in Deferred credits and will be returned to customers in the form of a rate reduction in the 2009 fiscal year and $2,268,000 was contributed to the Energy Efficiency Fund.

Example 2: Xcel Energy – extract from 10-K for the year ending on 31 December 2007

A4. Xcel Energy is a holding company, with subsidiaries engaged primarily in the utility business. In 2007, Xcel Energy's continuing operations included the activity of four wholly owned utility subsidiaries that serve electric and natural gas customers in eight states.

A5. The paragraph and table below is note 17 to the financial statements that specifically deals with regulatory assets and liabilities:

Note 17

Xcel Energy's regulated businesses prepare its consolidated financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 1 to the consolidated financial statements. Under SFAS No. 71, regulatory assets and liabilities can be created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of Xcel Energy's business that is not regulated cannot use SFAS No. 71 accounting. If changes in the utility industry or the business of Xcel Energy no longer allow for the application of SFAS No. 71 under GAAP, Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in its consolidated statement of income. The components of unamortized regulatory assets and liabilities of continuing operations shown on the consolidated balance sheets at Dec. 31 are presented in the table below.

	See Note(s)	Remaining Amortization Period	2007	2006
		(Thousands of Dollars)		
Regulatory Assets				
Current regulatory asset — Unrecovered fuel costs	1	Less than one year	$ 73,415	$ 258,600
Pension and employee benefit obligations	10	Various	$ 387,127	$ 475,815
AFDC recorded in plant[(a)]		Plant lives	189,698	179,023
Conservation programs[(a)]		Various	119,839	124,123
Contract valuation adjustments[(b)]	12	Term of relatedcontract	106,649	109,221
Losses on reacquired debt	1	Term of related debt	73,002	74,420
Environmental costs	15,16	Generally four to six years once actual expenditures are incurred	55,038	35,715
Renewable resource costs		One to two years	51,785	49,902
Net asset retirement obligations[(c)]	1,15	Plant lives	39,891	54,550
Unrecovered natural gas costs	1	One to two years	22,505	17,943
State commission accounting adjustments[(a)]		Various	13,828	13,950
MISO Day 2 costs	1	To be determined in future rate proceedings	12,035	11,014
Nuclear fuel storage		Four years	11,578	14,473
Nuclear decommissioning costs		To be determined in future rate proceedings	11,149	9,325
Rate case costs	1	Various	9,630	8,689
Other		Various	11,689	10,982
Total noncurrent regulatory assets			$ 1,115,443	$ 1,189,145
Regulatory Liabilities				
Current regulatory liability — Overrecovered fuel costs[(d)]			$ 34,451	$ 4,279
Plant removal costs	1,15		$ 906,996	$ 920,583
Pension and employee benefit obligations	10		205,133	196,803
Contract valuation adjustments[(b)]	12		108,533	56,745
Investment tax credit deferrals			72,686	78,205
Deferred income tax adjustments	1		59,282	67,002
Gain on sale of emission allowances	1		21,334	7,417
Interest on income tax refunds			3,472	5,233
Over recovered fuel costs			149	10,054
Other			12,402	22,615
Total noncurrent regulatory liabilities			$ 1,389,987	$ 1,364,657

(a) Earns a return on investment in the ratemaking process. These amounts are amortized consistent with recovery in rates.
(b) Includes the fair value of certain long-term purchased power agreements used to meet energy capacity requirements.
(c) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.
(d) Included in other current liabilities of $419,209 and $347,809 at Dec. 31, 2007 and 2006, respectively, in the consolidated balance sheets.

Example 3: Puget Energy – extract from 10-K for the year ending on 31 December 2008

A6. Puget Energy is a holding company that owns Puget Sound Energy, Inc. Puget Sound Energy is a public utility incorporated in the state of Washington that furnishes electric and natural gas services in a territory covering 6,000 square miles, primarily in the Puget Sound region. The company operates rate-regulated activities.

NOTE 21. *Regulation and Rates*

ELECTRIC REGULATION AND RATES
STORM DAMAGE DEFERRAL ACCOUNTING

On February 18, 2005, the Washington Commission issued a general rate case order that defined deferrable catastrophic/extraordinary losses and provided that costs in excess of $7.0 million annually may be deferred for qualifying storm damage costs that meet the Institute of Electrical and Electronics Engineers (IEEE) outage criteria for system average interruption duration index. PSE's storm accounting, which allows deferral of certain storm damage costs, was subject to review by the Washington Commission at the end of the current three-year period, which was December 31, 2007. In PSE's electric general rate case, the annual threshold at which qualifying storm costs may be deferred has been increased to $8.0 million beginning with calendar year 2009. In 2008, PSE incurred $11.4 million in storm-related electric transmission and distribution system restoration costs, of which $1.4 million was deferred. In 2007, PSE incurred $38.3 million in storm-related electric transmission and distribution system restoration costs, of which $29.3 million was deferred.

ELECTRIC GENERAL RATE CASE
On October 8, 2008, the Washington Commission issued its order in PSE's electric general rate case filed in December 2007, approving a general rate increase for electric customers of $130.2 million or 7.1% annually. The rate increase for electric gas customers was effective November 1, 2008. In its order, the Washington Commission approved a weighted cost of capital of 8.25%, or 7.00% after-tax, and a capital structure that included 46.0% common equity with a return on equity of 10.15%.

On January 5, 2007, the Washington Commission issued its order in PSE's electric general rate case filed in February 2006, approving a general rate decrease for electric customers of $22.8 million or 1.3% annually. The rates for electric customers became effective January 13, 2007. In its order, the Washington Commission approved a weighted cost of capital of 8.4%, or 7.06% after-tax, and a capital structure that included 44.0% common equity with a return on equity of 10.4%. The Washington Commission had earlier approved (on June 28, 2006) a power cost only rate case (PCORC) increase of $96.1 million annually effective July 1, 2006.

POWER COST ONLY RATE CASE
PCORC, a limited-scope proceeding, was approved in 2002 by the Washington Commission to periodically reset power cost rates. In addition to providing the opportunity to reset all power costs, the PCORC proceeding also provides for timely review of new resource acquisition costs and inclusion of such costs in rates at the time the new resource goes into service. To achieve this objective, the Washington Commission approved an expedited five-month PCORC decision timeline rather than the statutory 11-month timeline for a general rate case.

On March 20, 2007, PSE submitted a PCORC filing to request approval of an updated power cost baseline rate beginning September 2007. The PCORC filing also requested recovery of ownership and operating costs of the Goldendale generating facility (Goldendale) through retail electric rates. On May 23, 2007, PSE filed updated power costs due to changes in market conditions of natural gas and other costs which resulted in a revised proposed increase of $77.8 million or 4.4% annually. On July 5, 2007, a settlement agreement in this PCORC signed by PSE and certain other parties to the proceeding was filed with the Washington Commission, the terms of which included an electric rate increase of $64.7 million.

On August 2, 2007, the Washington Commission approved the settlement agreement and authorized an increase in PSE's electric rates of $64.7 million or an average increase of 3.7% annually effective September 1, 2007. The investment in Goldendale was found prudent, thus allowing for recovery of certain ownership and operating costs through electric retail rates effective September 1, 2007 along with updating other power costs.

In accordance with the August 2, 2007 Washington Commission order approving the PCORC settlement, PSE and other parties agreed to conduct a collaborative stakeholder review of the PCORC process to consider the scope and timing of the PCORC mechanism. The collaborative review included but was not limited to: (1) the number of PCORCs that a company will be allowed to file in any given year; (2) the number and timing of updates that a company may submit in the PCORC process; (3) the items directly associated with power costs that may be included and considered in a PCORC filing; and (4) whether the number and timing of updates may vary depending on if other parties can easily verify. On December 12, 2007 the collaboration filed a final report with the Washington Commission reporting that the parties were not able to reach agreement on revisions to the PCORC mechanism and that the parties would address such issues in the Company's pending general rate case filing. On January 15, 2009, the Washington Commission issued an order that authorized the continuation of the PCORC with certain modifications to which the Washington Commission staff and the Company agree. The five procedural modifications to the PCORC include extending the expected procedural schedule from five to six months, limiting the power cost updates to one per PCORC unless an additional update is allowed by the Washington Commission as part of the compliance filing, prohibiting the overlap of PCORC and general rate cases (except for requests for interim rate relief), shortening data request time from ten to five business days, and requiring the Company to provide its AURORA data files to Public Counsel and interveners at the outset of a case.

ACCOUNTING ORDERS AND PETITIONS

On April 26, 2006, the Washington Commission approved an accounting petition on a temporary basis to defer an $89.0 million one-time capacity reservation charge along with accrual of interest at the authorized after-tax rate of return. As part of the general rate case order of January 5, 2007, the Washington Commission approved the regulatory accounting treatment that had been approved in the accounting petition. The payment was made in relation to an agreement for the purchase of power from Chelan County PUD (Chelan). PSE and Chelan have entered into an agreement which provides for the purchase of 25.0% of the output of Chelan's Rock Island (622 MW) and Rocky Reach (1,237 MW) dams on the Columbia River. The agreement called for PSE to make a one-time payment of $89.0 million on April 27, 2006. Then, upon the expiration of the existing contracts in 2011, PSE will begin purchasing 25.0% of the output at the projects' costs for the next 20 years.

On April 11, 2007, the Washington Commission approved PSE's petition for issuance of an accounting order that authorizes PSE to defer certain ownership and operating costs (and associated carrying costs) PSE incurred related to its purchase of Goldendale during the period prior to inclusion in PSE's retail electric rates in the PCORC. The deferral is for the time period from March 15, 2007 through September 1, 2007. As of December 31, 2008, PSE had established a regulatory asset of $11.8 million. Recovery of these costs over a period of three years began November 2008 as allowed in the October 2008 general rate case order.

On April 13, 2007, PSE filed an accounting petition for a Washington Commission order authorizing the deferral and use of net revenues from the sale of Renewable Energy Credits (RECs) and Emission Reduction Allowances (ERA) to further the development of renewable generation resources in Washington State or to be credited to customers. The accounting petition also requests approval of amortization of the deferred REC and ERA proceeds to expense.

On May 30, 2007, PSE agreed to extend the terms of the existing leases of its Bellevue corporate office complex from ten years to 15 years. PSE's lease agreement included a one-time right to purchase the office complex. PSE elected to monetize the value of this purchase option and negotiated for a cash payment of $18.9 million, net of transaction fees, in exchange for the termination of the purchase option. PSE received authorization for deferred accounting treatment of the net proceeds in the 2007 General Rate Case. Amortization began effective November 1, 2008 for a period of 12 years.

On May 21, 2008, PSE filed an accounting petition for a Washington Commission order authorizing the deferral of a settlement payment of $10.7 million incurred as a result of the recent settlement of a lawsuit in the state of Montana over alleged damages caused by the operation of Colstrip.

On May 28, 2008, the Washington Commission authorized PSE to defer to a maximum of $2.3 million of costs associated with the FERC required studies of Baker River Dam. The accounting petition allows PSE to defer costs incurred from January 8, 2007 through December 31, 2010.

On November 5, 2008, PSE filed an accounting petition for a Washington Commission order authorizing the deferral and recovery of interest due the IRS for tax years 2001 to 2006 along with carrying costs incurred in connection with the interest due. In October 2005, the Washington Commission issued an order authorizing the deferral and recovery of costs associated with increased borrowings necessary to remit deferred taxes to the IRS.

On November 6, 2008, PSE filed an accounting petition for a Washington Commission order authorizing accounting treatment and amortization related to payments received for taking assignment of Westcoast Pipeline Capacity. The accounting petition seeks deferred accounting treatment and amortization of the regulatory liability to power costs beginning in November 2009 and extending over the remaining primary term of the pipeline capacity contract through October 31, 2018.

On November 15, 2008, PSE filed an accounting petition for a Washington Commission order determining that its newly acquired Mint Farm complies with the Washington State greenhouse gases (GHG) emissions performance standard. Under this standard PSE can defer the costs associated with Mint Farm until the cost of the plant is included in rates. The Company is currently deferring both variable and fixed costs as allowed. The Mint Farm purchase was completed on December 5, 2008. On December 23, 2008 the Washington Commission set this matter for hearing. PSE expects to receive an order by the third quarter 2009.

On December 30, 2008, the Washington Commission approved an order authorizing the sale of Puget Energy and PSE to Puget Holdings subject to a Settlement Stipulation which included 78 conditions. Items included in the conditions that may affect the financial statements are dividend restrictions for Puget Energy and PSE. These items are discussed in Note 6. In addition, the conditions provided for rate credits of $10.0 million per year due to merger savings and a lower return by the investor consortium over a ten-year period beginning at the closing of the transaction.

RESIDENTIAL EXCHANGE DEFERRED ASSET

On May 21, 2007, the BPA notified PSE and other investor-owned utilities that BPA was suspending payments related to its residential exchange program (REP) due to adverse Ninth Circuit Court of Appeals (Ninth Circuit) decisions of May 3, 2007. The Ninth Circuit concluded in its decisions that certain BPA actions in entering into residential exchange settlements in 2000 were not in accordance with the law. BPA suspended payments under the REP as a result of the Ninth Circuit decisions. As a result of the BPA suspension of payment, PSE filed revisions to the tariffs which pass through the benefits of the REP to all residential and small farm customers. The Washington Commission approved the termination of the Residential Exchange Credit effective June 7, 2007. Under Federal law investor-owned utilities receiving REP benefits must pass-through the benefits to their residential and small farm electric customers.

On August 29, 2007, the Washington Commission approved PSE’s accounting petition to defer as a regulatory asset the excess REP benefit provided to customers and accrue monthly carrying charges on the deferred balance from June 7, 2007 until the deferral is recovered from customers or BPA. The accounting petition sought approval to record carrying costs on the deferred balance until the deferred balance is recovered from customers. In March 2008, BPA and PSE signed an agreement pursuant to which BPA (on April 2, 2008) paid PSE $53.7 million in REP benefits for fiscal year ending September 30, 2008, which payment is subject to true-up depending upon the amount of any REP benefits ultimately determined to be payable to PSE. In April 2008, the Washington Commission approved PSE’s tariff filing seeking to pass-through the net amount of the benefits under the interim agreements to residential and small farm customers. The Washington Commission also approved PSE’s request to credit the regulatory asset amount of $33.7 million against the $53.7 million payment and pass-through to customers the remaining amount of approximately $20.0 million, which occurred during the second quarter 2008. These amounts did not affect PSE’s net income. PSE began amortization of the accrued carrying charges on the regulatory asset totaling $3.1 million at September 30, 2008 on November 1, 2008 over a two year period as determined in PSE's electric general rate case. On October 30, 2008, the Washington Commission approved PSE's tariff request to resume the REP pass-through credits to residential electric customers. The result is a 9.9% reduction to residential electric customers bill without an impact on earnings.

PRODUCTION TAX CREDIT

PSE has a tariff schedule which passes the benefits of the Production Tax Credit (PTCs) to customers based on estimated generation of the PTC credits. PSE may adjust the PTC tariff annually based on differences between the PTC credits provided to the customers and the PTC credits actually earned, plus estimated PTC credits for the following year, less interest associated with the deferred tax balance for the PTC credits. The tariff is not subject to the sharing bands in the PCA. Since customers receive the benefit of the tax credits as they are generated and the Company does not receive a credit from the IRS until the tax credits are utilized, the Company is reimbursed for its carrying costs for funds through this calculation.

On October 30, 2006, PSE revised its PTC electric tariff to increase the revenue credit to customers from $13.1 million to $28.8 million, effective January 1, 2007. On December 12, 2007, PSE revised its PTC electric tariff to decrease the revenue credit to customers from $28.8 million to $28.6 million, effective January 12, 2008. PSE will be revising the tariff effective January 1, 2009 based on a filing made in the fourth quarter 2008.

PCA MECHANISM

In 2002, the Washington Commission approved a PCA mechanism that triggers if PSE's costs to provide customers' electricity varies from a power cost baseline rate established in a rate proceeding. The cumulative maximum pre-tax earnings exposure due to power cost variations over the four-year period ending June 30, 2006 was limited to $40.0 million plus 1.0% of the excess. In October 2005, the Washington Commission approved a shift to an annual PCA measurement period from January through December starting in 2007. On January 5, 2007, the Washington Commission approved the continuation of the PCA mechanism under the same annual graduated scale without a cumulative cap for excess power costs. All significant variable power supply cost variables (hydroelectric and wind generation, market price for purchased power and surplus power, natural gas and coal fuel price, generation unit forced outage risk and transmission cost) are included in the PCA mechanism.

The PCA mechanism apportions increases or decreases in power costs, on a calendar year basis, between PSE and its customers on a graduated scale:

	Annual Power Cost Variability		July-December 2006 Power Cost Variability[1]	Customers' Share	Company's Share
+/-	$20 million	+/-	$10 million	0%	100 %
+/-	$20 - $40 million	+/-	$10 - $20 million	50 %	50 %
+/-	$40 - $120 million	+/-	$20 - $60 million	90 %	10 %
+/-	$120 million	+/-	$60 million	95 %	5 %

GAS REGULATION AND RATES

GAS GENERAL RATE CASE

On October 8, 2008, the Washington Commission issued its order in PSE's natural gas general rate case filed in December 2007, approving a general rate increase for natural gas rates of $49.2 million or 4.6% annually. The rate increases for natural gas customers were effective November 1, 2008. In its order, the Washington Commission approved a weighted cost of capital of 8.25%, or 7.00% after tax and a capital structure that included 46.0% common equity with a return on equity of 10.15%.

[1] *In October 2005, the Washington Commission in its PCORC order allowed for a reduction to the power cost variability amounts to half the annual power cost variability for the period July 1, 2006 through December 31, 2006*

On January 5, 2007, the Washington Commission issued its order in PSE's natural gas general rate case, granting an increase for natural gas customers of $29.5 million or 2.8% annually, effective beginning January 13, 2007 which resulted in an increase in gas margin of approximately 9.8% annually. In its order the Washington Commission approved the same weighted cost of capital of 8.4%, or 7.06% after-tax and capital structure that included 44.0% common equity with a return on equity of 10.4%, consistent with the Company's electric operations.

PURCHASED GAS ADJUSTMENT

PSE has a PGA mechanism in retail natural gas rates to recover variations in gas supply and transportation costs. Variations in gas rates are passed through to customers, therefore PSE's gas margin and net income are not affected by such variations. On September 25, 2008, the Washington Commission approved PSE's requested revisions to its PGA tariff schedules resulting in an increase of $108.8 million or 11.1% on an annual basis in gas sales revenues effective October 1, 2008. The rate increase was the result of higher costs of natural gas in the forward market and a reduction of the credit for the accumulated PGA payable balance. The PGA rate change will increase PSE's revenue but will not impact the Company's net income as the increased revenue will be offset by increased purchased gas costs.

The following rate adjustments were approved by the Washington Commission in relation to the PGA mechanism during 2008, 2007 and 2006:

EFFECTIVE DATE	PERCENTAGE INCREASE (DECREASE) IN RATES	ANNUAL INCREASE (DECREASE) IN REVENUES (DOLLARS IN MILLIONS)
October 1, 2008	11.1 %	$ 108.8
October 1, 2007	(13.0) %	(148.1)
October 1, 2006	10.2 %	95.1