BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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In the Matter of the Application of PACIFICORP (U 901 E), an Oregon Company, for an Order Authorizing a Rate Increase Effective January 1, 2011 and Granting Conditional Authorization to Transfer Assets, pursuant to the Klamath Hydroelectric Settlement Agreement	Application No. A.10-_A1003015_ (Filed March 18, 2010)

APPLICATION OF PACIFICORP (U-901-E) FOR AN ORDER AUTHORIZING A RATE INCREASE AND GRANTING CONDITIONAL AUTHORIZATION TO TRANSFER ASSETS PURSUANT TO THE KLAMATH HYDROELECTRIC SETTLEMENT AGREEMENT

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Date: March 18, 2010

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

In the Matter of the Application of PACIFICORP (U 901 E), an Oregon Company, for an Order Authorizing a Rate Surcharge Effective January 1, 2011 and Granting Conditional Authorization to Transfer Assets, pursuant to the Klamath Hydroelectric Settlement Agreement	Application No. A.10-______ (Filed March 18, 2010)

APPLICATION OF PACIFICORP (U-901-E) FOR AN ORDER AUTHORIZING A RATE SURCHARGE AND GRANTING CONDITIONAL AUTHORIZATION TO TRANSFER ASSETS PURSUANT TO THE KLAMATH HYDROELECTRIC SETTLEMENT AGREEMENT

Pursuant to Rules 2.1 and 3.2 of the Commission's Rules of Practice and Procedure ("Rules") and Sections 451, 454, 491, 701, 728, and 729 of the California Public Utilities Code ("PUC"), PacifiCorp, d.b.a. Pacific Power ("PacifiCorp" or "Company"), respectfully submits this application ("Application") requesting that this Commission:

- establish a non-bypassable rate surcharge beginning on January 1, 2011 in California to fund the removal of four PacifiCorp dams located on the Klamath River ("Project") to be remitted by PacifiCorp into two trust accounts to be created by the Commission at the request of the state of California, which accounts shall be managed and administered by an agency of the state of California, to hold and disburse the funds collected through the rate surcharge pursuant to the provisions of the Klamath Hydroelectric Settlement Agreement ("KHSA");

- approve an accelerated depreciation schedule that will depreciate the rate base associated with the Project on a straight-line basis over the expected period of generation, which could end as early as December 31, 2019; and
- pursuant to Section 851 of the California Public Utilities Code[1], authorize PacifiCorp to transfer the Project and related lands to the entity that will be designated to remove the dams according to the terms of the KHSA. The Section 851 authorization will be conditioned upon the completion of specific milestones set forth in the KHSA, and shall be implemented by means of a separate authorization to transfer each of the four dams, which authorizations will become effective upon the filing by PacifiCorp of a separate compliance advice letter for each of the dams confirming that all of the condition precedents for the removal of each dam have been accomplished.

As described below, PacifiCorp proposes an initial target surcharge collection totaling $13.76 million. This number represents California's share, or 8 percent, of the total initial target surcharge collection of $172 million.[2] The $13.76 million is proposed to be spread equally over a 9-year period resulting in annual collections of approximately $1.53 million a year.

The rate surcharge, along with the establishment of two trusts for the funds collected, are key components of the KHSA. The accelerated depreciation schedule and authority to transfer the Project and related lands under Section 851 are likewise important aspects of the KHSA. The KHSA, which was negotiated by numerous parties over the course of many years, is crucial to the resolution of long-standing, complex and intractable conflicts over resources in the Klamath Basin, including the Project. Importantly, the federal government and the states of

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[1] All statutory references to a Section refer to the California Public Utilities Code unless stated otherwise.
[2] The remainder of the initial total target surcharge is to be collected from PacifiCorp's Oregon customers. While the KHSA provides for a maximum customer surcharge of $200 million, the Parties to the KHSA assumed that interest will accrue at 3.5 percent on the $172 million collected, which will result in trust funds of $200 million by 2020. See Appendix H of the KHSA.

California and Oregon are all parties to the KHSA, and have endorsed its provisions. By approving this Application, consistent with the decision of the Governor of California to support the KHSA, the Commission's order will implement key provisions of the KHSA and will benefit PacifiCorp's customers as the net cost to customers under the KHSA compares favorably to the potential costs to customers if PacifiCorp continued to seek Federal Energy Regulatory Commission ("FERC") relicensing of the dams. In addition, the KHSA ensures that PacifiCorp's customers will continue to benefit from the low-cost power of the dams for at least 10 years, and until the dams are finally removed.

I. BACKGROUND

As the Commission is aware, PacifiCorp is a multi-jurisdictional utility providing electric retail service to customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp serves approximately 46,500 customers in Del Norte, Modoc, Shasta, and Siskiyou counties in Northern California.

A. 2009 General Rate Case (A.09-11-015)

The Company filed its most recent general rate case in California, which is still pending before this Commission, on November 20, 2009 (A.09-11-015). Application 09-11-015 requested approval of an overall revenue requirement increase of $8.4 million to recover increased costs and an 11 percent return on equity. The proposed $8.4 million increase would represent an overall rate increase of 9.6 percent for PacifiCorp's California retail customers, effective January 1, 2011, and is necessitated by significant investments the Company is making to its system in order to continue to provide safe and reliable service.

The rate surcharge requested in this Application is in addition to the rate increase requested in A.09-11-015. However, the revenue requirement impact of the accelerated depreciation schedule requested in this Application is reflected in PacifiCorp's 2009 General Rate Case Application. That Application includes an adjustment to the depreciation allowances for rate base that reflects the shorter depreciation life for the Project assets, as well as the addition to rate base of the relicensing and settlement process costs.

II. SUMMARY OF APPLICATION

A. Rate Surcharge

PacifiCorp is requesting Commission authorization to initially collect a non-bypassable rate surcharge totaling $13.68 million. This amount represents California's proportionate share, approximately 8 percent, of the overall initial surcharge collection of $172 million. The rate surcharge is for the purpose of funding California's contribution to the removal of four PacifiCorp dams located on the Klamath River.

The dam removal is expected to occur no earlier than 2020. PacifiCorp is requesting that the dam removal surcharge become effective January 1, 2011. This will result in the $13.76 million being collected equally over a period of 9 years, which will result in an annual collection rate of approximately $1.53 million a year over the 9-year period. The collection rate may need to be adjusted in the future to reflect variations in collections due to changes in kilowatt hour ("kWh") usage or other factors. The Company will monitor collections against the target revenues and propose adjustments as necessary. In addition, the KHSA specifically requires that the surcharge not exceed 2 percent of the revenue requirement set by this Commission for PacifiCorp as of January 1, 2010. PacifiCorp has, therefore, compared the annual collection rate against its revenue requirement in California as of January 1, 2010 and confirmed that the annual collection rate does not exceed 2 percent.

Furthermore, the KHSA requires that the surcharge be allocated among customer classes in an equitable manner. PacifiCorp is proposing to allocate the surcharge among customer classes based on each class' share of generation revenues, while ensuring that the impact on each customer class does not exceed 2 percent and is not less than 1.5 percent. The surcharge will likely increase an average residential customer's monthly bill by approximately $1.61 per month, or $19.32 per year.

The proposed rate surcharge and the collection and allocation of the surcharge are consistent with the terms of the KHSA. Importantly, the KHSA also provides significant benefits to PacifiCorp's customers. The KHSA protects customers from uncertain costs related to dam removal by capping the amount of customer contributions for removal costs. The KHSA also protects customers from any liability associated with dam removal by requiring federal legislation that provides liability protection for PacifiCorp and its customers as a condition precedent to dam removal. In addition, the KHSA will provide benefits to PacifiCorp's customers as the costs to customers of dam removal under the KHSA compare favorably to the potential costs to customers of FERC relicensing and future litigation related to controversies in the Klamath Basin region. Finally, the KHSA ensures that PacifiCorp's customers will continue to benefit from the low-cost power of the dams until the dams are removed.

Pursuant to the provisions of the KHSA, the dam removal surcharge funds would be remitted by PacifiCorp to two trusts established by this Commission in response to a request from the state of California as required by the terms of the KHSA. The KHSA provides that the Commission shall create the trusts in a manner that ensures that the surcharge funds will not be taxable revenues of PacifiCorp. PacifiCorp will be responsible for collecting the surcharge, but will not have any control over the trusts. Instead, the trusts will be managed and administered by an agency of the state of California. The trustee instructions are to be developed in coordination with the federal government and the state of Oregon, which is in the process of creating parallel trusts for surcharge revenue collected from PacifiCorp customers in that state. The trustee instructions will provide specific guidance on the appropriate manner and method of management and disbursement of the trusts' funds. Furthermore, the KHSA includes specific instructions for the disposition of funds if there are any remaining unused funds or if the dams will not be removed. In any such instance, the remaining funds must be used for the benefit of customers, through contributions to the relicensing of the facilities or other beneficial programs associated with the Project, or through customer refunds.

These trusts would be similar in nature to the nuclear decommission trusts established by the Commission in Decisions 83-04-013 and 87-05-062. In D. 83-04-013, the Commission determined to authorize the use of such trusts for the purpose of financing the costs of decommissioning nuclear plants. The Commission reasoned that the trusts would: (i) assure that the funds collected would be available when needed; (ii) impose reasonable costs on customers; (iii) be flexible enough to respond to changing circumstances; and (iv) be equitable due to the levelized method of collecting ratepayer contributions, which were spread over the years of the plants' operations and over the customers benefitting from the generation produced by the reactors.

B. Accelerated Depreciation

PacifiCorp is also requesting the approval of an accelerated depreciation schedule for its remaining investment in the Project. The Company proposes to depreciate the net book value of its remaining investment in the Project on a straight-line basis over the expected remaining period of generation, which is anticipated to end as early as December 31, 2019. The relicensing and settlement process costs have been reflected in PacifiCorp's General Rate Case Application and are proposed to be amortized on a straight-line basis over the same period as the Project facilities. If the revised depreciation schedule is approved in this proceeding, it will be implemented as part of a final Commission decision in the General Rate Case proceeding. The annual rate impact of the revised depreciation schedule as well as the addition to rate base of the relicensing and settlement process costs is approximately $330,000.

C. Section 851 Approval

Finally, PacifiCorp is requesting authorization, under Section 851, to transfer the Project and related lands to the entity that will be designated to remove the dams. This authorization is to be conditioned upon the accomplishment of key milestones set forth in the KHSA, specifically:

1. the passage of federal legislation which contain provisions that are materially consistent with Section 2.1.1.A of the KHSA;
2. the availability of sufficient funds to cover the estimated costs of dam removal, provided by the states of California and Oregon, as set forth in Section 4.1 of the KHSA;
3. an Affirmative Determination by the Secretary of the U.S. Department of the Interior determining that: (i) the costs of dam removal will not exceed available funds; (ii) removal of the dams will advance restoration of the salmonid fisheries of the Klamath Basin; and (iii) removal of the dams is in the public interest, as required in Section 3 of the KHSA; and
4. the issuance by the Dam Removal Entity ("DRE") of the DRE Notice, as defined in Section 7.4.1 of the KHSA, at such time as all necessary permits and approvals have

been obtained for the removal of a main stem dam ("Facility"), all contracts necessary for Facility Removal have been finalized, and Facility Removal is ready to commence.

Due to the fact that the DRE may finalize the required permitting and contracting for removal of each of the Facilities at different times, the KHSA provides that the DRE shall issue a DRE Notice for each such Facility, when and as appropriate.[3] Accordingly, PacifiCorp proposes that the requested Section 851 transfer authorization would be implemented by means of a separate authorization to transfer each Facility, which authorizations will become effective upon the filing by PacifiCorp of a separate compliance Advice Letter filing for each such Facility pursuant to General Order No. 96-B, Electric Industry Rule 5.1. Such "Tier 1" Advice Letters as defined by this rule are appropriate when taking actions specifically authorized by a prior Commission decision or order. As Tier 1 Advice Letters implement specific provisions of Commission decisions, and become effective upon filing, they do not require further action such as a Commission resolution. If the Commission, in this proceeding, conditionally approves the transfer of the Project assets subject to the fulfillment of the conditions precedent set forth above, at the appropriate time, PacifiCorp will seek to exercise the authority for the transfer by objectively demonstrating to the Commission through Tier 1 Advice Letters that all the conditions for removal of each of the Facilities have been met.

Following the issuance of a Commission decision in this proceeding conditionally authorizing the transfer of assets subject to the filing of such an Advice Letter, the Commission shall retain regulatory jurisdiction over the Project, and PacifiCorp shall maintain the status quo

[3] In addition to the four main stem dams, PacifiCorp also seeks authorization to transfer other Project assets to the DRE and the states of Oregon and California, pursuant to the KHSA. Under the terms of the KHSA, the transfer of the Keno dam, the PacifiCorp Hatchery Facilities, and specified Klamath Hydroelectric Project lands to said entities are to occur upon the issuance by the DRE of a DRE Notice for particular main stem dam associated with such assets. See KHSA, Sections 7.4 and 7.6.

with regard to its ownership and operation of each portion of the Project until such time as the compliance Advice Letters are filed.

III. STATUTORY AND REGULATORY REQUIREMENTS

A. Statutory and Other Authority (Rule 2.1)

Rule 2.1 requires that all applications state clearly and concisely the authorization or relief sought; cite by appropriate reference the statutory provision or other authority under which Commission authorization or relief is sought; and be verified by the applicant. The relief being sought is summarized in Section II above and is further described in the testimony and supporting exhibits accompanying this Application. The statutory and other authority under which this relief is being sought includes Rules 2.1 and 3.2, Sections 451, 454, 491, 701, 728, 729, and 851 of the PUC, and prior decisions, orders and resolutions of this Commission. This Application has been verified by an officer of PacifiCorp as provided in Rules 1.1 and 2.1.

B. Proposed Categorization, Need for Hearing, Issues to be Considered, and Proposed Schedule (Rule 2.1(c))

Rule 2.1(c) requires PacifiCorp to state "[t]he proposed category for the proceeding, the need for hearing, the issues to be considered, and a proposed schedule." PacifiCorp proposes that the Commission classify this proceeding as "ratesetting."[4] PacifiCorp acknowledges the need for evidentiary hearings in this matter and proposes the following procedural schedule:

[4] Rule 1.3(e) defines "Ratesetting" as "proceedings in which the Commission sets or investigates rates for a specifically named utility (or utilities), or establishes a mechanism that in turn sets the rates for a specifically named utility (or utilities). . . ."

Event	Estimated Timeline
Application Filed	March 18, 2010
Application Noticed in Daily Calendar	March 29, 2010
Protests Due	April 28, 2010
Response to Protests Due	May 10, 2010
Prehearing Conference	May 20, 2010
Scoping Memo Issued	June 1, 2010
Public Participation Hearings	Should be held concurrently with the Public Participation Hearings in PacifiCorp's GRC
DRA and Interested Party Testimony Due	July 15, 2010
PacifiCorp Rebuttal Testimony Due	August 16, 2010
Evidentiary Hearings (anticipate 4 days)	August 30, 2010
Opening Briefs	October 1, 2010
Reply Briefs	October 11, 2010
Proposed Decision Issued	November 15, 2010
Comments on PD Due	December 6, 2010
Reply Comments on PD Due	December 13, 2010
Commission Order	December 16, 2010

PacifiCorp specifically requests that the Public Participation Hearings in this case take place concurrently with the Public Participation Hearings in PacifiCorp's General Rate Case. This will place less of a burden on customers who might like to participate in both Public Participation Hearings and reduce any confusion regarding the subjects to be addressed at the different Public Participation Hearings.

C. Legal Name and Correspondence – Rules 2.1(a) and (b)

PacifiCorp is a public utility organized and existing under the laws of the state of Oregon. PacifiCorp engages in the business of generating, transmitting, and distributing electric energy in portions of Northern California and in the states of Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's principal place of business is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232.

Communications regarding this Application should be addressed to:

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In addition, PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By E-mail (preferred):	datarequest@PacifiCorp.com
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232

D. Organization and Qualification to Transact Business – (Rule 2.2)

A certified copy of PacifiCorp's Articles of Incorporation, as amended, and presently in effect, was filed with the Commission in A.97-05-011, which resulted in Commission issuance of D.97-12-093 and is incorporated herein by reference pursuant to Rule 2.2.

E. CEQA Compliance – (Rule 2.4)

No CEQA analysis is required for this Application. The Company is requesting only the funding and transfer authority necessary to facilitate removal of the dams, not authorization to remove the dams themselves. Thus this Application does not seek a discretionary Commission order approving a "project" under CEQA. Environmental review issues will be addressed prior to actual dam removal by other California, Oregon, and federal agencies responsible for granting discretionary permits to the DRE for the removal of the dams.

F. Balance Sheet and Income Statement – (Rule 3.2(a)(1))

A copy of PacifiCorp's recent financial statements, contained in the Annual Report on Form 10-K, filed March 1, 2010 with the Securities and Exchange Commission, for the period ending December 31, 2009, is included herein as Appendix A.

G. Present and Proposed Rates – (Rule 3.2(a)(2) and (3))

Appendix B to this Application contains a table which sets forth existing rates for PacifiCorp's California customers, and the rate impact of the KHSA surcharge requested in this Application. Also shown is the estimated rate impact of the depreciation adjustments requested in this Application pursuant to the KHSA, which adjustments have been reflected in the General Rate Case filed by PacifiCorp in A.09-11-015 and are shown here for illustrative purposes only.

H. List of Testimony

Accompanying this Application are Exhibit Nos. PPL/100 through PPL/301, the prefiled Direct Testimony and Exhibits sponsored by PacifiCorp witnesses Mr. Dean S. Brockbank, Ms. Andrea L. Kelly, and Mr. Cory E. Scott. Exhibits accompanying Mr. Brockbank's testimony include the Project location and the chronology of events which led to the KHSA, the KHSA and relevant information to explain the KHSA. PacifiCorp's submissions to support this Application include the following:

Exhibit PPL/100 – Direct Testimony of Dean S. Brockbank

<u>Supporting Exhibits</u>:
Exhibit PPL/101 – Map of the Klamath Project
Exhibit PPL/102 – Klamath Chronology
Exhibit PPL/103 – Summary of KHSA
Exhibit PPL/104 – Klamath Hydroelectric Settlement Agreement

Exhibit PPL/200 – Direct Testimony of Andrea L. Kelly

<u>Supporting Exhibits</u>:
Exhibit PPL/201 – Proposed Schedule 199 –Klamath Dam Removal Surcharge and supporting calculations

Exhibit PPL/300 – Direct Testimony of Cory E. Scott

<u>Supporting Exhibits</u>:
Exhibit PPL/301 – Klamath Document Inventory

I. Summary of Earnings of PacifiCorp Stated for California Operations and for the Total Company – (Rule 3.2(a)(5) and (6))

The statement of earnings included in this Application as Appendix C are stated on both a total Company basis, which includes all of PacifiCorp's utility operations, and on a California specific basis.

K. Statement of Basis for Requested Increase – (Rule 3.2 (a)(10))

The rate increase requested by PacifiCorp through this Application reflects and passes through to customers in California a percentage of the anticipated costs for removal of the Project as required by Section 4 of the KHSA. In addition, an accelerated depreciation schedule for the Company's remaining investment in the Project is also being sought in this Application pursuant to the same provision of the KHSA.

L. Public Notice – (Rule 3.2(b), (c) and (d))

The cities and towns that would be affected by the rate changes resulting from this Application include Yreka, Crescent City, Alturas, Mount Shasta, Weed, Dunsmuir, Fort Jones, Dorris and Tulelake. The counties affected by this Application are Siskiyou, Del Norte, Modoc and Shasta. As provided in Rule 3.2(b), (c) and (d), notice of filing of this Application will be: (1) mailed to the appropriate officials of the state of California, specifically the Attorney General and Department of General Services, and the counties and cities listed above; (2) published in a newspaper of general circulation in each county in PacifiCorp's service territory within which the rate changes would be effective; (3) included with regular bills mailed to all customers affected by the proposed changes; and (4) mailed to any other persons whom PacifiCorp deems appropriate, including all parties to the current General Rate case proceeding of PacifiCorp before this Commission.

IV. CONCLUSION

WHEREFORE, PacifiCorp respectfully requests that the Commission issue an order, effective January 1, 2011, approving the rate increase proposed herein, approving the revised depreciation schedule, and authorizing it to be implemented in PacifiCorp's pending General Rate Case, and granting PacifiCorp the conditional authority it seeks to transfer the Project assets under Section 851, subject to the filing of the appropriate compliance Advice Letters as set forth above.

Respectfully submitted this March 18, 2010 at San Francisco, California.

By ______________________________
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OFFICER VERIFICATION

(Rule 1.11)

I am an officer of the reporting corporation herein, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury under the laws of the state of California that the foregoing is true and correct.

Executed on March 18, 2010 at Portland, Oregon.

Andrea Kelly

Andrea L. Kelly
Vice President, Regulation

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Date: March 18, 2010

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On March 18, 2010, PacifiCorp filed an application with the California Public Utilities Commission ("CPUC") requesting authorization to establish a rate surcharge beginning January 1, 2011, to fund California's share of the costs related to removal of four dams on the Klamath River pursuant to the terms of the Klamath Hydroelectric Settlement Agreement ("KHSA"). The funds collected through the surcharge would be placed into trust accounts to be established by the CPUC. If the conditions of the KHSA are met, the dams would be removed no earlier than 2020. The application demonstrates that the cost to customers associated with the KHSA compares favorably to continuing to seek relicensing of the dams. In addition, the KHSA protects customers from any liability associated with dam removal and ensures that customers continue to benefit from the low-cost power of the dams until they are removed.

The Application filing consists of: (1) the Application; (2) Appendices A, B and C to the Application; (3) supporting testimony and exhibits of Dean S. Brockbank; (4) supporting testimony and exhibit of Andrea L. Kelly; and (5) supporting testimony and exhibit of Cory E. Scott.

The above-described items exceed 50 pages in length and would cause the entire email message, including all attachments, to exceed 3.5 megabytes in size. Therefore, pursuant to Rule 1.9 of the Commission's Rules of Practice and Procedure, PacifiCorp is filing this Notice of Availability of Application of PacifiCorp (U-901-E) for an Order Authorizing a Rate Surcharge and Granting Conditional Authorization to Transfer Assets Pursuant to the Klamath Hydroelectric Settlement Agreement to the service list for this proceeding in lieu of serving actual or electronic copies of these materials. The Application and supporting materials are available as of March 18, 2010 at the following URL:

http://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/California/PDF_Name.pdf

Upon request, PacifiCorp will also provide hard copies of the Application and other materials described above. To expedite service of the requested materials, PacifiCorp asks that requests be submitted in writing by email to:

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Respectfully submitted this March 18, 2010 at San Francisco, California.

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Certificate of Service

I, Ariel Son, certify that I have on this 18th day of March 2010 caused a copy of the foregoing **Notice of Availability of Application of PacifiCorp (U 901-E) for an Order Authorizing a Rate Increase and Granting Conditional Authorization to Transfer Assets Pursuant to the Klamath Hydroelectric Settlement Agreement** to be served on all known parties to A.09-11-015 listed on the most recently updated service list available on the California Public Utilities Commission website, via email to those listed with email and via U.S. mail to those without email service.

Service List
A.09-11-015

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PacifiCorp is on this same day also serving via E-mail or US Mail a true and correct copy of the **Notice of Availability of Application of PacifiCorp (U 901-E) for an Order Authorizing a Rate Increase and Granting Conditional Authorization to Transfer Assets Pursuant to the Klamath Hydroelectric Settlement Agreement** on the following parties:

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PacifiCorp is on this same day also serving via Overnight Delivery a true and correct copy of the **Application of PacifiCorp (U 901-E) for an Order Authorizing a Rate Increase and Granting Conditional Authorization to Transfer Assets Pursuant to the Klamath Hydroelectric Settlement Agreement** on the following parties:

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I declare under penalty of perjury that the foregoing is true and correct.
Executed this 18th day of March 2010 at Portland, Oregon.

Ariel Son
Coordinator, Regulatory Operations

Appendix A

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2009

or

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from _____ to _____

Commission File Number	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
1-5152	**PACIFICORP** **(An Oregon Corporation)** **825 N.E. Multnomah Street** **Portland, Oregon 97232** **503-813-5000**	**93-0246090**

Securities registered pursuant to Section 12(b) of the Act: None
Securities registered pursuant to Section 12(g) of the Act:

Title of each Class

5% Preferred Stock (Cumulative; $100 Stated Value)
Serial Preferred Stock (Cumulative; $100 Stated Value)
No Par Serial Preferred Stock (Cumulative; $100 Stated Value)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ☐ No ☒

As of January, 31, 2010, there were 357,060,915 shares of common stock outstanding. All shares of outstanding common stock are indirectly owned by MidAmerican Energy Holdings Company, 666 Grand Avenue, Des Moines, Iowa.

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Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can typically be identified by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon PacifiCorp's current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside PacifiCorp's control and could cause actual results to differ materially from those expressed or implied by PacifiCorp's forward-looking statements. These factors include, among others:

- general economic, political and business conditions in the jurisdictions in which PacifiCorp's facilities operate;
- changes in federal, state and local governmental, legislative or regulatory requirements, including those pertaining to income taxes, affecting PacifiCorp or the electric utility industry;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce plant output or delay plant construction;
- the outcome of general rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies;
- changes in economic, industry or weather conditions, as well as demographic trends, that could affect customer growth and usage or supply of electricity or PacifiCorp's ability to obtain long-term contracts with customers;
- a high degree of variance between actual and forecasted load and prices that could impact the hedging strategy and costs to balance electricity and load supply;
- hydroelectric conditions, as well as the cost, feasibility and eventual outcome of hydroelectric relicensing proceedings, that could have a significant impact on electric capacity and cost and PacifiCorp's ability to generate electricity;
- changes in prices, availability and demand for both purchases and sales of wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generation capacity and energy costs;
- the financial condition and creditworthiness of PacifiCorp's significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital, including reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in the London Interbank Offered Rate, the base interest rate for PacifiCorp's credit facilities;
- changes in PacifiCorp's credit ratings;
- performance of PacifiCorp's generating facilities, including unscheduled outages or repairs;
- the impact of derivative contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in the commodity prices, interest rates and other conditions that affect the fair value of derivative contracts;
- increases in employee healthcare costs and the potential impact of federal healthcare reform legislation;
- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on pension and other postretirement benefits expense and funding requirements;
- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future generating facilities and infrastructure additions;
- the impact of new accounting pronouncements or changes in current accounting estimates and assumptions on consolidated financial results;
- other risks or unforeseen events, including litigation, wars, the effects of terrorism, embargoes and other catastrophic events; and

- other business or investment considerations that may be disclosed from time to time in PacifiCorp's filings with the United States Securities and Exchange Commission ("SEC") or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting PacifiCorp are described in Item 1A and other discussions contained in this Form 10-K. PacifiCorp undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exclusive.

PART I

Item 1. Business

General

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric company serving 1.7 million retail customers, including residential, commercial, industrial and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, 78 thermal, hydroelectric, wind-powered and geothermal generating facilities, with a net owned capacity of 10,483 megawatts ("MW"). PacifiCorp also owns, or has interests in, electric transmission and distribution assets, and transmits electricity through approximately 15,900 miles of transmission lines. PacifiCorp also buys and sells electricity on the wholesale market with public and private utilities, energy marketing companies and incorporated municipalities as a result of excess electricity generation or other system balancing activities. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining facilities and services and environmental remediation services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa, that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). MEHC controls substantially all of PacifiCorp's voting securities, which include both common and preferred stock.

PacifiCorp's principal executive offices are located at 825 N.E. Multnomah Street, Suite 2000, Portland, Oregon 97232, and its telephone number is (503) 813-5000. PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly-formed Oregon corporation. The resulting Oregon corporation was re-named PacifiCorp, which is the operating entity today.

Berkshire Hathaway Equity Commitment

On March 1, 2006, MEHC and Berkshire Hathaway entered into an Equity Commitment Agreement (the "Berkshire Equity Commitment") pursuant to which Berkshire Hathaway has agreed to purchase up to $3.5 billion of MEHC's common equity upon any requests authorized from time to time by MEHC's Board of Directors. The proceeds of any such equity contribution shall only be used by MEHC for the purpose of (a) paying when due MEHC's debt obligations and (b) funding the general corporate purposes and capital requirements of MEHC's regulated subsidiaries, including PacifiCorp. Berkshire Hathaway will have up to 180 days to fund any such request in increments of at least $250 million pursuant to one or more drawings authorized by MEHC's Board of Directors. The funding of each drawing will be made by means of a cash equity contribution to MEHC in exchange for additional shares of MEHC's common stock. PacifiCorp has no right to make or to cause MEHC to make any equity contribution requests. The Berkshire Equity Commitment expires on February 28, 2011.

Operations

PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power. PacifiCorp's electric generation, commercial and trading, and coal mining functions are operated under the trade name PacifiCorp Energy. As a vertically integrated electric utility, PacifiCorp owns or has contracts for fuel sources, such as coal and natural gas, and uses these fuel sources, as well as water resources, wind and geothermal to generate electricity at its generating facilities. This electricity, together with electricity purchased on the wholesale market, is then transmitted via a grid of transmission lines throughout PacifiCorp's six-state service area and the Western United States. The electricity is then transformed to lower voltages and delivered to customers through PacifiCorp's distribution system.

PacifiCorp's primary goal is to provide safe, reliable electricity to its customers at a reasonable cost. In return, PacifiCorp expects that all prudently incurred costs to provide such service will be included as allowable costs for state ratemaking purposes, and PacifiCorp will be allowed an opportunity to earn a reasonable return on its investments.

PacifiCorp seeks to manage growth in its customer demand through the construction and purchase of new cost-effective, environmentally prudent and efficient sources of power supply and through demand response and energy efficiency programs. During 2009, PacifiCorp placed in service 265 MW of wind-powered generating facilities to help meet future retail load growth, achieve renewable generation targets and replace expiring wholesale supply contracts.

Employees

As of December 31, 2009, PacifiCorp, together with its subsidiaries, had 6,447 employees, 60% of which were covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America, the International Brotherhood of Boilermakers and the United Mine Workers of America.

Service Territories

PacifiCorp's combined service territory covers approximately 136,000 square miles and includes diverse regional economies ranging from rural, agricultural and mining areas to urban, manufacturing and government service centers. No single segment of the economy dominates the service territory, which helps mitigate PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, mainly consisting of Utah, Wyoming and southeastern Idaho, the principal industries are manufacturing, recreation, agriculture and mining or extraction of natural resources. In the western portion of the service territory, mainly consisting of Oregon, southern Washington and northern California, the principal industries are agriculture and manufacturing, with forest products, food processing, technology and primary metals being the largest industrial sectors.

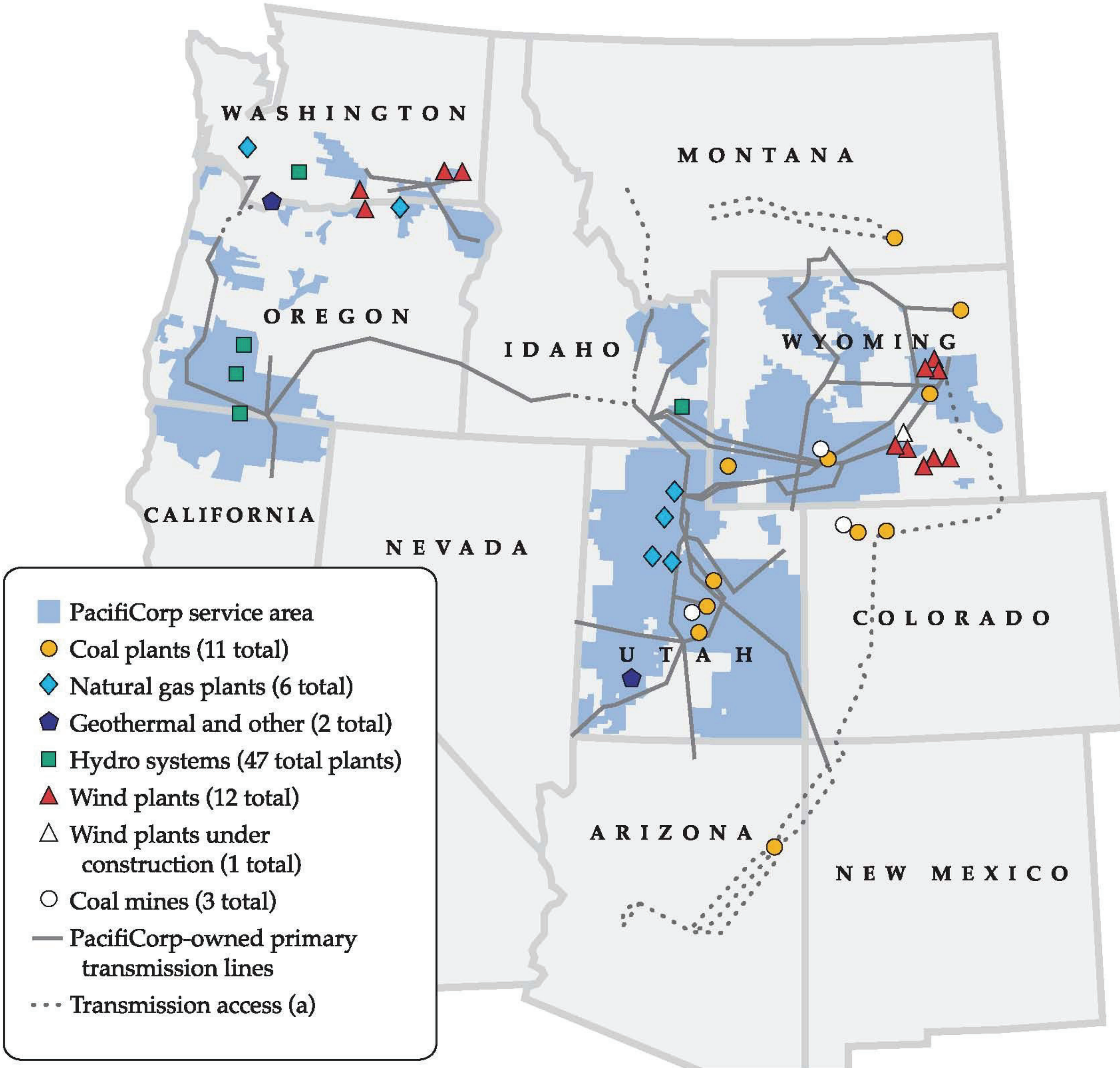
PacifiCorp receives authorization from state public utility commissions to serve areas within each state. This authorization is perpetual until withdrawn. In addition, PacifiCorp has received franchises that permit it to provide electric service to customers inside incorporated areas within the states. The average term of these franchises is approximately 30 years, although their terms range from five years to indefinite. PacifiCorp must renew franchises as they expire. Governmental agencies have the right to challenge PacifiCorp's right to serve in a specific area and can condemn PacifiCorp's property under certain circumstances. However, PacifiCorp vigorously challenges attempts from individuals and governmental agencies to undertake forced takeover of portions of its service territory.

Except for Oregon and Washington, PacifiCorp has an exclusive right to serve customers within its service territories, and in turn, has the obligation to provide electric service to those customers. Under Oregon law, PacifiCorp has the exclusive right and obligation to provide electric distribution services to all customers within its allocated service territory; however, nonresidential customers have the right to choose alternative electricity service suppliers. The impact of these programs on PacifiCorp's consolidated financial results has not been material. In Washington, state law does not provide for exclusive service territory allocation. PacifiCorp's service territory in Washington is surrounded by other public utilities with whom PacifiCorp has from time to time entered into service area agreements under the jurisdiction of the Washington Utilities and Transportation Commission ("WUTC").

The percentages of electricity sold to retail customers by jurisdiction were as follows for the years ended December 31:

	2009	2008	2007
Utah	42%	42%	42%
Oregon	25	26	26
Wyoming	17	17	16
Washington	8	7	8
Idaho	6	6	6
California	2	2	2
	100%	100%	100%

The following map highlights PacifiCorp's retail service territory, generating facility locations and PacifiCorp's primary transmission lines as of December 31, 2009. PacifiCorp's generating facilities are interconnected through PacifiCorp's own transmission lines or by contract through transmission lines owned by others.



(a) Access to other entities' transmission lines through wheeling arrangements.

Customers

Retail sales volumes depend on factors such as economic conditions, including the timing of recovery from the current economic recession, population growth, consumer trends, voluntary and mandated conservation efforts, weather, technology and price changes.

Electricity sold to retail and wholesale customers and the average number of retail customers, by class of customer, were as follows for the years ended December 31:

	2009		2008		2007	
Gigawatt hours ("GWh") sold:						
Residential	15,999	24%	16,222	24%	15,975	24%
Commercial	16,194	25	16,055	24	15,951	24
Industrial	19,934	31	21,495	32	20,892	31
Other	583	1	590	1	572	1
Total retail	52,710	81	54,362	81	53,390	80
Wholesale	12,349	19	12,345	19	13,724	20
Total GWh sold	65,059	100%	66,707	100%	67,114	100%
Average number of retail customers (in thousands):						
Residential	1,467	85%	1,458	86%	1,441	86%
Commercial	214	13	210	12	205	12
Industrial	34	2	34	2	34	2
Other	4	-	4	-	4	-
Total	1,719	100%	1,706	100%	1,684	100%
Retail customers:						
Average usage per customer (kilowatt hours)	30,672		31,863		31,712	
Average revenue per customer	$ 2,047		$ 2,021		$ 1,931	
Revenue per kilowatt hour	6.7¢		6.3¢		6.1¢	

Customer Usage and Seasonality

In addition to the variations in weather from year to year, fluctuations in economic conditions within the service territory and elsewhere can impact customer usage, particularly for industrial and wholesale customers. Beginning in the fourth quarter of 2008, certain customer usage levels began to decline due to the effects of the economic conditions in the United States. The declining usage trend continued in 2009, resulting in lower retail demand than in 2008.

Peak customer demand is typically highest in the summer across PacifiCorp's service territory when air conditioning and irrigation systems are heavily used. The service territory also has a winter peak, which is primarily due to heating requirements in the western portion of PacifiCorp's service territory. Peak demand represents the highest demand on a given day and at a given hour. During the year ended December 31, 2009, PacifiCorp's peak demand was 9,420 MW in the summer and 9,336 MW in the winter.

Power and Fuel Supply

The percentage of PacifiCorp's energy requirements by resource varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages; fuel commodity prices; fuel transportation costs; weather; environmental considerations; transmission constraints; and wholesale market prices of electricity. When factors for one generation resource are unfavorable, PacifiCorp must place more reliance on other energy sources. For example, PacifiCorp can generate more electricity using its low cost hydroelectric and wind-powered generating facilities when factors associated with these facilities are favorable. When hydroelectric and wind resources are less favorable, PacifiCorp must increase its reliance on more expensive generation or purchased electricity. PacifiCorp manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be derivatives, including forwards, futures, options, swaps and other agreements. Refer to Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

PacifiCorp's portfolio of generating facilities was comprised of the following as of December 31, 2009:

	Location	Energy Source	Installed	Facility Net Capacity (MW) (1)	Net Owned Generating Capacity (MW)(1)
COAL:					
Jim Bridger	Rock Springs, WY	Coal	1974-1979	2,117	1,411
Hunter Nos. 1, 2 and 3	Castle Dale, UT	Coal	1978-1983	1,320	1,122
Huntington	Huntington, UT	Coal	1974-1977	895	895
Dave Johnston	Glenrock, WY	Coal	1959-1972	762	762
Naughton	Kemmerer, WY	Coal	1963-1971	700	700
Cholla No. 4	Joseph City, AZ	Coal	1981	395	395
Wyodak	Gillette, WY	Coal	1978	335	268
Carbon	Castle Gate, UT	Coal	1954-1957	172	172
Craig Nos. 1 and 2	Craig, CO	Coal	1979-1980	856	165
Colstrip Nos. 3 and 4	Colstrip, MT	Coal	1984-1986	1,480	148
Hayden Nos. 1 and 2	Hayden, CO	Coal	1965-1976	446	78
				9,478	6,116
NATURAL GAS:					
Lake Side	Vineyard, UT	Natural gas/steam	2007	558	558
Currant Creek	Mona, UT	Natural gas/steam	2005-2006	550	550
Chehalis	Chehalis, WA	Natural gas/steam	2003	520	520
Hermiston	Hermiston, OR	Natural gas/steam	1996	474	237
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1955	231	231
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	122	122
Little Mountain	Ogden, UT	Natural gas	1971	14	14
				2,469	2,232
HYDROELECTRIC: (2)					
Lewis River System (3)	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System (4)	OR	Hydroelectric	1950-1956	200	200
Klamath River System (5)	CA, OR	Hydroelectric	1903-1962	170	170
Bear River System (6)	ID, UT	Hydroelectric	1908-1984	105	105
Rogue River System (7)	OR	Hydroelectric	1912-1957	52	52
Minor hydroelectric facilities	Various	Hydroelectric	1895-1986	53	53
				1,158	1,158
WIND: (2)					
Marengo	Dayton, WA	Wind	2007	140	140
Leaning Juniper 1	Arlington, OR	Wind	2006	101	101
High Plains	McFadden, WY	Wind	2009	99	99
Rolling Hills	Glenrock, WY	Wind	2009	99	99
Glenrock	Glenrock, WY	Wind	2008	99	99
Seven Mile Hill	Medicine Bow, WY	Wind	2008	99	99
Goodnoe Hills	Goldendale, WA	Wind	2008	94	94
Marengo II	Dayton, WA	Wind	2008	70	70
Foote Creek	Arlington, WY	Wind	1999	41	33
Glenrock III	Glenrock, WY	Wind	2009	39	39
McFadden Ridge I	McFadden, WY	Wind	2009	28	28
Seven Mile Hill II	Medicine Bow, WY	Wind	2008	20	20
				929	921
OTHER: (2)					
Blundell	Milford, UT	Geothermal	1984, 2007	34	34
Camas Co-Gen	Camas, WA	Black liquor	1996	22	22
				56	56
Total available generating capacity				14,090	10,483

(1) Facility net capacity (MW) represents the total capability of a generating unit as demonstrated by actual operating or test experience, less power generated and used for auxiliaries and other station uses, and is determined using average annual temperatures. Net owned generating capacity (MW) indicates current legal ownership. For wind-powered generating facilities, nominal ratings are used in place of facility net capacity. A wind turbine generator's nominal rating is the manufacturer's contractually specified capability (in MW) under specified conditions.

(2) All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards ("RPS") or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

(3) The license for these facilities is valid through May 2058.

(4) The license for these facilities is valid through October 2038.

(5) The license for these facilities was valid through February 2006 and it currently operates on annual licenses. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for an update regarding hydroelectric relicensing for the Klamath River system.

(6) The license is valid through March 2024 for Cutler and through November 2033 for the Grace, Oneida and Soda hydroelectric generating facilities.

(7) The license is valid through December 2018 for Prospect No. 3 and through March 2038 for the Prospect Nos. 1, 2 and 4 hydroelectric generating facilities.

The percentages of PacifiCorp's total energy supplied by energy source were as follows for the years ended December 31:

	2009	2008	2007
Coal	63%	65%	64%
Natural gas	12	12	11
Hydroelectric	5	5	5
Other [(1)]	4	2	1
Total energy generated	84	84	81
Energy purchased – long-term contracts	6	5	5
Energy purchased – short-term contracts and other	10	11	14
	100%	100%	100%

(1) All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with RPS or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Coal

Coal-fired generating facilities account for 58% of PacifiCorp's total net owned generating capacity. PacifiCorp owns coal mines that support its coal-fired generating facilities. These mines supplied 31% of PacifiCorp's total coal requirements during each of the years ended December 31, 2009, 2008 and 2007. The remaining coal requirements are acquired through long- and short-term third-party contracts. PacifiCorp's mines are located adjacent to many of its coal-fired generating facilities, which significantly reduces overall transportation costs included in fuel expense. Most of PacifiCorp's coal reserves are held pursuant to leases from the federal government through the Bureau of Land Management and from certain states and private parties. The leases generally have multi-year terms that may be renewed or extended only with the consent of the lessor and require payment of rents and royalties. In addition, federal and state regulations require that comprehensive environmental protection and reclamation standards be met during the course of mining operations and upon completion of mining activities.

Coal reserve estimates are subject to adjustment as a result of the development of additional engineering and geological data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. Recoverable coal reserves as of December 31, 2009, based on PacifiCorp's most recent engineering studies, were as follows (in millions):

Location	Plant Served	Mining Method	Recoverable Tons
Craig, CO	Craig	Surface	46 (1)
Huntington & Castle Dale, UT	Huntington and Hunter	Underground	30 (2)
Rock Springs, WY	Jim Bridger	Surface	83 (3)
Rock Springs, WY	Jim Bridger	Underground	50 (3)
			209

(1) These coal reserves are leased and mined by Trapper Mining, Inc., a Delaware non-stock corporation operated on a cooperative basis, in which PacifiCorp has an ownership interest of 21%. The amount included above represents only PacifiCorp's 21% interest in the coal reserves.

(2) These coal reserves are leased by PacifiCorp and mined by a wholly owned subsidiary of PacifiCorp.

(3) These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc. ("PMI") and a subsidiary of Idaho Power Company. PMI, a wholly owned subsidiary of PacifiCorp, has a two-thirds interest in the joint venture. The amount included above represents only PacifiCorp's two-thirds interest in the coal reserves.

Recoverability by surface mining methods typically ranges from 90% to 95%. Recoverability by underground mining techniques ranges from 50% to 70%. To meet applicable standards, PacifiCorp blends coal mined at its owned mines with contracted coal and utilizes emission reduction technologies for controlling sulfur dioxide and other emissions. For fuel needs at PacifiCorp's coal-fired generating facilities in excess of coal reserves available, PacifiCorp believes it will be able to purchase coal under both long- and short-term contracts to supply its remaining coal-fired generating facilities with coal over their currently expected useful lives.

During the year ended December 31, 2009, PacifiCorp-owned coal-fired generating facilities held sufficient sulfur dioxide emission allowances to comply with the United States Environmental Protection Agency (the "EPA") Title IV requirements.

Natural Gas

PacifiCorp's natural gas-fired generating facilities account for 21% of PacifiCorp's total net owned generating capacity. PacifiCorp uses natural gas as fuel for its combined- and simple-cycle natural gas-fired generating facilities. Oil and natural gas are also used for igniter fuel and to fuel generation for transmission support and standby purposes. In determining whether to dispatch its natural gas-fired generating facilities, PacifiCorp considers, among other factors, its operational requirements to balance electricity supply and demand and the current spark spread. Spark spread is the difference between the wholesale market price of electricity at any given hour and the cost to convert natural gas to electricity.

PacifiCorp manages its natural gas supply requirements by entering into forward commitments for physical delivery of natural gas. PacifiCorp also manages its exposure to increases in natural gas supply costs through forward commitments for the purchase of forecasted physical natural gas requirements at fixed prices and financial swap contracts that settle in cash based on the difference between a fixed price that PacifiCorp pays and a floating market-based price that PacifiCorp receives. As of December 31, 2009, PacifiCorp had economically hedged 53% of its forecasted physical exposure and 95% of its forecasted financial exposure for 2010. For 2011, PacifiCorp has currently hedged 26% of its forecasted physical exposure and 87% of its forecasted financial exposure.

Hydroelectric

Hydroelectric generating facilities account for 11% of PacifiCorp's total net owned generating capacity. The amount of electricity PacifiCorp is able to generate from its hydroelectric facilities depends on a number of factors, including snowpack in the mountains upstream of its hydroelectric facilities, reservoir storage, precipitation in its watersheds, generating unit availability and restrictions imposed by oversight bodies due to competing water management objectives.

PacifiCorp operates the majority of its hydroelectric generating portfolio under long-term licenses from the Federal Energy Regulatory Commission (the "FERC") with terms of 30 to 50 years, while some are licensed under the Oregon Hydroelectric Act. PacifiCorp expects to incur ongoing operating and maintenance expense and capital expenditures associated with the terms of its renewed hydroelectric licenses and settlement agreements, including natural resource enhancements. PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses. Substantially all of PacifiCorp's remaining hydroelectric generating facilities are operating under licenses that expire between 2030 and 2058. As of December 31, 2009 and 2008, PacifiCorp had \$67 million and \$57 million, respectively, in costs related to the relicensing of the Klamath hydroelectric system included in construction work-in-progress within property, plant and equipment, net on the Consolidated Balance Sheets. For a further discussion of PacifiCorp's hydroelectric relicensing and decommissioning activities, refer to "Hydroelectric Relicensing – Klamath River Hydroelectric Facilities" and "Hydroelectric Decommissioning – Condit Hydroelectric Facility – White Salmon River, Washington" below.

Wind and Other Renewable Resources

PacifiCorp is pursuing additional renewable resources as viable, economic and environmentally prudent means of supplying electricity. Renewable resources have low to no emissions, require little or no fossil fuel and are complemented by PacifiCorp's other generating facilities and wholesale transactions. PacifiCorp's wind-powered generating facilities are eligible for federal renewable electricity production tax credits ("PTCs") for 10 years from the date that the facilities were placed in service. In February 2009, legislation was passed extending the date by which such facilities must be placed in service to be eligible for PTCs to December 31, 2012.

Wholesale Activities

PacifiCorp purchases electricity in the wholesale markets as needed to serve its retail load and long-term wholesale sales obligations and for system balancing requirements. PacifiCorp also purchases electricity in the wholesale markets when it is more economical than generating it at its own facilities. Many of PacifiCorp's purchased electricity contracts have fixed-price components, which provide some protection against price volatility. PacifiCorp sells electricity into the wholesale market arising from imbalances between generation and retail load obligations and to optimize the utilization of generation assets.

Transmission and Distribution

PacifiCorp's electric transmission system is part of the Western Interconnection, the regional grid in the West. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico that make up the Western Electricity Coordinating Council (the "WECC"). The map under "Service Territories" above shows PacifiCorp's primary transmission system. PacifiCorp operates one balancing authority area in the western portion of its service territory and one balancing authority area in the eastern portion of its service territory. A balancing authority area is a geographic area with electric transmission systems that control generation to maintain schedules with other balancing authority areas and ensure reliable operations. In operating the balancing authority areas, PacifiCorp is responsible for continuously balancing electric supply and demand by dispatching generating resources and interchange transactions so that generation internal to the balancing authority area, plus net imported power, matches customer loads. PacifiCorp also schedules deliveries of energy over its transmission system in accordance with FERC requirements.

As of December 31, 2009, PacifiCorp owned, or participated in, an electric transmission system consisting of approximately:

Nominal Voltage (in kilovolts) Transmission Lines	Miles [1]
500	700
345	2,100
230	3,400
161	300
138	2,200
46 to 115	7,200
	15,900

(1) Includes PacifiCorp's share of jointly owned lines.

PacifiCorp's electric transmission and distribution system included approximately 900 substations as of December 31, 2009. PacifiCorp's transmission system, together with contractual rights on other transmission systems, enables PacifiCorp to integrate and access generating resources to meet its customer load requirements.

PacifiCorp's Energy Gateway Transmission Expansion Program represents plans to build approximately 2,000 miles of new high-voltage transmission lines, with an estimated cost exceeding $6 billion, primarily in Wyoming, Utah, Idaho, Oregon and the desert Southwest. The plan includes several transmission line segments that will: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse resource areas, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area and the Western United States. Proposed transmission line segments are re-evaluated to ensure maximum benefits and timing before committing to move forward with permitting and construction. The first major transmission segments associated with this plan are expected to be placed in service during 2010, with other segments placed in service through 2019, depending on siting, permitting and construction schedules.

Substantially all of PacifiCorp's generating facilities and reservoirs are managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. Portions of PacifiCorp's transmission and distribution systems are located:

- On property owned or leased by PacifiCorp;
- Under or over streets, alleys, highways and other public places, the public domain and national forests and state lands under franchises, easements or other rights that are generally subject to termination;
- Under or over private property as a result of easements obtained primarily from the record holder of title; or
- Under or over Native American reservations under grant of easement by the United States Secretary of Interior or lease by Native American tribes.

It is possible that some of the easements, and the property over which the easements were granted, may have title defects or may be subject to mortgages or liens existing at the time the easements were acquired.

Future Generation and Conservation

Integrated Resource Plan

As required by certain state regulations, PacifiCorp uses an Integrated Resource Plan ("IRP") to develop a long-term view of prudent future actions required to help ensure that PacifiCorp continues to provide reliable and cost-effective electric service to its customers. The IRP process identifies the amount and timing of PacifiCorp's expected future resource needs and an associated optimal future resource mix that accounts for planning uncertainty, risks, reliability impacts, state energy policies and other factors. The IRP is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. PacifiCorp files its IRP on a biennial basis, and for four of its six state jurisdictions, receives a formal notification as to whether the IRP meets the commission's IRP standards and guidelines. In May 2009, PacifiCorp filed its 2008 IRP with each of its state commissions. During 2009, PacifiCorp received orders from states of Washington and Idaho acknowledging that the IRP met their applicable standards and guidelines. In February 2010, the Oregon Public Utility Commission ("OPUC") issued an order acknowledging the 2008 IRP. Acknowledgment of the 2008 IRP by the Utah Public Service Commission ("UPSC") is pending.

Requests for Proposals

PacifiCorp has issued a series of separate Requests for Proposals ("RFPs"), each of which focuses on a specific category of resources consistent with the IRP. The IRP and the RFPs provide for the identification and staged procurement of resources in future years to achieve a balance of load requirements and resources. As required by applicable laws and regulations, PacifiCorp files draft RFPs with the UPSC, the OPUC and the WUTC prior to issuance to the market. Approval by the UPSC, the OPUC or the WUTC may be required depending on the nature of the RFPs.

In August 2009, under PacifiCorp's 2008R-1 renewable resources RFP (approved by the OPUC in September 2008), PacifiCorp executed a power purchase agreement to purchase the entire output of the proposed 200-MW Top of the World wind-powered generating facility located in Wyoming. The generation of the energy and associated renewable energy credits under this agreement are expected to commence in December 2010 and continue for a period of 20 years. PacifiCorp's 2009R renewable resources RFP (approved by the OPUC with modification in July 2009) seeks additional cost-effective renewable generation projects with no single resource greater than 300 MW, combined total resources of no more than 400 MW and on-line dates no later than December 31, 2012. As a result of the 2009R renewable resources RFP, PacifiCorp's 111-MW Dunlap Ranch I wind-powered generating facility located in Wyoming was selected and construction has commenced. Negotiations were also initiated with the remaining final shortlist bidder under the 2009R renewable resources RFP.

In October 2009, PacifiCorp filed a request for approval with the UPSC to re-issue the All Source RFP, which was previously suspended in April 2009. In October 2009 and November 2009, respectively, the UPSC and the OPUC approved resumption of the All Source RFP. The All Source RFP seeks up to 1,500 MW on a system wide basis from projects with in-service dates from 2014 through 2016. In December 2009, the All Source RFP was issued to the market.

Demand-side Management

PacifiCorp has provided a comprehensive set of demand-side management ("DSM") programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, PacifiCorp offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to solicit participation in load management programs by residential, business and agricultural customers through programs, such as PacifiCorp's residential and small commercial air conditioner load control program and irrigation equipment load control programs. Subject to random prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency service charges paid by retail electric customers. In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 342 MW of load reduction when needed. Recovery for the costs associated with the large industrial load management program is determined through PacifiCorp's general rate case process. In 2009, $106 million was expended on the DSM programs in PacifiCorp's six-state service area, resulting in an estimated 457,000 megawatt hours ("MWh") of first-year energy savings and 441 MW of peak load management. Total demand-side load available for control in 2009, including both load management from the large industrial curtailment contracts and DSM programs, was 783 MW.

General Regulation

PacifiCorp is subject to comprehensive governmental regulation, which significantly influences its operating environment, prices charged to customers, capital structure, costs and ability to recover costs.

State Regulation

PacifiCorp pursues a regulatory program in all states, with the objective of keeping rates closely aligned to ongoing costs. Historically, state utility commissions have established rates on a cost-of-service basis, which are designed to allow a utility an opportunity to recover its costs of providing services and to earn a reasonable return on its investments. A utility's cost of service generally reflects its allowed operating expenses, including energy costs, operation and maintenance expense, depreciation expense and income and other tax expense, reduced by wholesale electric sales and other revenue. State utility commissions may adjust rates pursuant to a review of (a) the utility's revenue and expenses during a defined test period and (b) the utility's level of investment. State utility commissions typically have the authority to review and change rates on their own initiative. States may also initiate reviews at the request of a utility, utility customer, a governmental agency or a representative of a group of customers. The utility and such parties, however, may agree with one another not to request a review of or changes to rates for a specified period of time.

In addition to recovery through general rates, PacifiCorp also achieves recovery of certain costs through various adjustment mechanisms as summarized below. Refer to "Liquidity and Capital Resources" in Item 7 of this Form 10-K for additional information regarding regulatory matters, including the status of current filings with the various state commissions.

State Regulator	Base Rate Test Period	Adjustment Mechanism
Utah Public Service Commission	Forecasted or historical with known and measurable changes [(1)]	PacifiCorp has requested approval of an energy cost adjustment mechanism ("ECAM") to recover the difference between base net power costs set during a general rate case and actual net power costs.
		A recovery mechanism is available for a single capital investment project that in total exceeds 1% of existing rate base when a general rate case has occurred within the preceding 18 months.
Oregon Public Utility Commission	Forecasted	Annual transition adjustment mechanism ("TAM"), a mechanism for annual rate adjustments for forecasted net variable power costs; no true-up to actual net variable power costs.
		Renewable adjustment clause ("RAC") to recover the revenue requirement of new renewable resources and associated transmission that are not reflected in general rates.
		Annual true-up of taxes authorized to be collected in rates compared to taxes paid by PacifiCorp, as defined by Oregon statute and administrative rules under Oregon Senate Bill 408 ("SB 408").
Wyoming Public Service Commission ("WPSC")	Forecasted or historical with known and measurable changes [(1)]	Power cost adjustment mechanism ("PCAM") based on forecasted net power costs, later trued-up to actual net power costs, subject to dead bands and customer sharing.
Washington Utilities and Transportation Commission	Historical with known and measurable changes	Deferral mechanism of costs for up to 24 months of new base load generation resources and eligible renewable resources that qualify under the state's emissions performance standard and are not reflected in general rates.
Idaho Public Utilities Commission ("IPUC")	Historical with known and measurable changes	ECAM to recover the difference between base net power costs set during a general rate case and actual net power costs, subject to customer sharing and other adjustments.
California Public Utilities Commission ("CPUC")	Forecasted	Post test-year adjustment mechanism for major capital additions ("PTAM – capital additions"), a mechanism that allows for rate adjustments outside of the context of a traditional rate case for the revenue requirement associated with capital additions exceeding $50 million on a total-company basis. Filed as eligible capital additions are placed into service.
		Energy cost adjustment clause ("ECAC") that allows for an annual update to actual and forecasted net variable power costs.
		Post test-year adjustment mechanism for attrition ("PTAM – attrition"), a mechanism that allows for an annual adjustment to costs other than net variable power costs.

(1) PacifiCorp has relied on both historical test periods with known and measurable adjustments and forecasted test periods. The WPSC has not issued a final ruling on its preference between historical or forecasted test periods.

PacifiCorp's energy efficiency program costs are collected through separately established rates that are adjusted periodically based on actual and expected costs, as approved by the respective state utility commission.

Federal Regulation

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act, the Energy Policy Act and other federal statutes. The FERC regulates rates for interstate sales of electricity in wholesale markets; transmission of electric power, including pricing and expansion of transmission systems; electric system reliability; utility holding companies; accounting; securities issuances; and other matters, including construction and operation of hydroelectric projects. The FERC also has the enforcement authority to assess civil penalties of up to $1 million per day per violation of rules, regulations and orders issued under the Federal Power Act. PacifiCorp has implemented programs that facilitate compliance with the FERC regulations described below, including having instituted compliance monitoring procedures.

Wholesale Electricity and Capacity

The FERC regulates PacifiCorp's rates charged to wholesale customers for electricity and transmission capacity and related services. Most of PacifiCorp's wholesale electric sales and purchases take place under market-based pricing allowed by the FERC and are therefore subject to market volatility.

The FERC conducts a triennial review of PacifiCorp's market-based pricing authority. PacifiCorp must demonstrate the lack of market power in order to charge market-based rates for sales of wholesale electricity and electric generation capacity in its balancing authority areas. PacifiCorp's next triennial filing is due in June 2010. Under the FERC's market-based rules, PacifiCorp must also file a notice of change in status when there is a significant change in the conditions that the FERC relied upon in granting market-based pricing authority. PacifiCorp is currently authorized to sell at market-based rates.

Transmission

PacifiCorp's wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's Open Access Transmission Tariff ("OATT"). In accordance with its OATT, PacifiCorp offers several transmission services to wholesale customers:

- Network transmission service (guaranteed service that integrates generating resources to serve retail loads);
- Long- and short-term firm point-to-point transmission service (guaranteed service with fixed delivery and receipt points); and
- Non-firm point-to-point service ("as available" service with fixed delivery and receipt points).

These services are offered on a non-discriminatory basis, which means that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's transmission business is managed and operated independently from its commercial and trading business, in accordance with the FERC Standards of Conduct.

For retail customers, transmission costs are not separated from, but rather are "bundled" with, generation and distribution costs in rates approved by state regulatory commissions.

FERC Order No. 890 – Preventing Undue Discrimination and Preference in Transmission Service ("Order No. 890")

In February 2007, the FERC adopted a final rule in Order No. 890 designed to strengthen the pro forma OATT by providing greater specificity and increasing transparency. The most significant revisions to the pro forma OATT relate to the development of more consistent methodologies for calculating available transfer capability, changes to the transmission planning process, changes to the pricing of certain generator and energy imbalances to encourage efficient scheduling behavior and changes regarding long-term point-to-point transmission service, including the addition of conditional firm long-term point-to-point transmission service and generation re-dispatch. The FERC has issued rules through a set of subsequent orders clarifying Order No. 890. As a transmission provider with an OATT on file with the FERC, PacifiCorp is required to comply with the requirements of the new rule. PacifiCorp made its first compliance filing amending its OATT in July 2007. The FERC has continued to issue rules through a set of subsequent orders clarifying Order No. 890. In response to these various orders, PacifiCorp has made several required compliance filings.

FERC Reliability Standards

The FERC has approved an extensive number of reliability standards developed by the North American Electric Reliability Corporation (the "NERC") and the WECC, including critical infrastructure protection standards and regional standard variations. PacifiCorp must comply with all applicable standards. Compliance, enforcement and monitoring oversight of these standards is carried out by the FERC and the WECC. During 2007, the WECC audited PacifiCorp's compliance with several of the approved reliability standards, and in November 2008, the FERC assumed control of certain aspects of the WECC's audit. In May 2009, PacifiCorp received a notice of alleged violation and proposed sanctions related to the portions of the WECC's 2007 audit that remained with the WECC. In July 2009, PacifiCorp reached a settlement in principle with the WECC. The results of the settlement will not have a material impact on PacifiCorp's consolidated financial results. Refer to Note 13 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information regarding certain aspects of the WECC's 2007 audit currently under the FERC's authority.

Hydroelectric Relicensing – Klamath River Hydroelectric Facilities

PacifiCorp's Klamath hydroelectric system is the only hydroelectric generating facility for which PacifiCorp is engaged in the relicensing process with the FERC. PacifiCorp also has requested the FERC to allow decommissioning of certain hydroelectric systems. Most of PacifiCorp's hydroelectric generating facilities are licensed by the FERC as major systems under the Federal Power Act, and certain of these systems are licensed under the Oregon Hydroelectric Act. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for an update regarding hydroelectric relicensing for PacifiCorp's Klamath hydroelectric system.

Hydroelectric Decommissioning – Condit Hydroelectric Facility – White Salmon River, Washington

In September 1999, a settlement agreement to remove the 14-MW Condit hydroelectric facility was signed by PacifiCorp, state and federal agencies and non-governmental organizations. Under the original settlement agreement, removal was expected to begin in October 2006, with a total cost to decommission not to exceed $17 million, excluding inflation. In early February 2005, the parties agreed to modify the settlement agreement so that removal would not begin until October 2008, with a total cost to decommission not to exceed $21 million, excluding inflation. The settlement agreement is contingent upon receiving a FERC surrender order and other regulatory approvals that are not materially inconsistent with the amended settlement agreement. PacifiCorp is in the process of acquiring all necessary permits within the terms and conditions of the amended settlement agreement. Given the ongoing permitting process and the time needed for system removal and to evaluate impacts on natural resources, decommissioning is now expected to begin no earlier than October 2010. In March 2008, the United States Army Corps of Engineers requested PacifiCorp complete an additional study of expected decommissioning impacts on aquatic resources. In January 2009, the study work was completed and the results were provided to the United States Army Corps of Engineers and the Washington Department of Ecology. In January 2010, the Washington Department of Ecology released the Final Second Supplemental Environmental Impact Statement which formally considered this additional information. Absent further information requests, the Washington Department of Ecology is expected to complete the Clean Water Act 401 certification process within the second quarter of 2010. Remaining permitting includes a 404 permit from the United States Army Corps of Engineers and a surrender order from the FERC.

Northwest Refund Case

For a discussion of the Northwest Refund case, refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

United States Mine Safety

PacifiCorp's mining operations are regulated by the federal Mine Safety and Health Administration ("MSHA"), which administers federal mine safety and health laws, regulations and state regulatory agencies. The Mine Improvement and New Emergency Response Act of 2006 ("MINER Act"), enacted in June 2006, amended previous mine safety and health laws to improve mine safety and health and accident preparedness. PacifiCorp is required to develop a written emergency response plan specific to each underground mine it operates. These plans must be reviewed by MSHA every six months. It also requires every mine to have at least two rescue teams located within one hour, and it limits the legal liability of rescue team members and the companies that employ them. The MINER Act also increases civil and criminal penalties for violations of federal mine safety standards and gives MSHA the ability to institute a civil action for relief, including a temporary or permanent injunction, restraining order or other appropriate order against a mine operator who fails to pay the penalties or fines.

Environmental Laws and Regulation

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, climate change, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various other state, local and international agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and PacifiCorp is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. PacifiCorp believes it is in material compliance with all applicable laws and regulations.

Refer to "Liquidity and Capital Resources" in Item 7 of this Form 10-K for additional information regarding environmental laws and regulation and PacifiCorp's forecasted environmental-related capital expenditures.

Item 1A. Risk Factors

We are subject to numerous risks, including, but not limited to, those set forth below. Careful consideration of these risks, together with all of the other information included in this Form 10-K and the other public information filed by us, should be made before making an investment decision. Additional risks and uncertainties not presently known or that are currently deemed immaterial may also impair our business operations.

Our Corporate and Financial Structure Risks

We have a substantial amount of debt, which could adversely affect our ability to obtain future financing and limit our expenditures.

As of December 31, 2009, we had \$6.372 billion in total debt securities outstanding. Our principal financing agreements contain restrictive covenants that limit our ability to borrow funds, and any issuance of debt securities requires prior authorization from certain of our state regulatory commissions. We expect that we may need to supplement cash generated from operations and availability under committed credit facilities with new issuances of long-term debt. However, if market conditions are not favorable for the issuance of long-term debt, or if an issuance of long-term debt would exceed contractual or regulatory limits, we may postpone planned capital expenditures, or take other actions, to the extent those expenditures are not fully covered by cash from operations, borrowings under committed credit facilities or equity contributions from MEHC.

A downgrade in our credit ratings could negatively affect our access to capital, increase the cost of borrowing or raise energy transaction credit support requirements.

Our debt securities and preferred stock are rated investment grade by various rating agencies. We cannot assure that our debt securities and preferred stock will continue to be rated investment grade in the future. Although none of our outstanding debt has rating-downgrade triggers that would accelerate a repayment obligation, a credit rating downgrade would increase our borrowing costs and commitment fees on our revolving credit agreements and other financing arrangements, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings, and the potential pool of investors and funding sources would likely decrease. Further, access to the commercial paper market, the principal source of short-term borrowings, could be significantly limited resulting in higher interest costs.

Most of our large customers, suppliers and counterparties require sufficient creditworthiness in order to enter into transactions, particularly in the wholesale energy markets. If our credit ratings were to decline, especially below investment grade, financing costs and borrowing would likely increase because certain counterparties may require collateral in the form of cash, a letter of credit or some other security for existing transactions, as well as a condition to further transactions with us.

MEHC could exercise control over us in a manner that would benefit MEHC to the detriment of our creditors and preferred stockholders.

MEHC, through its subsidiary, owns all of our common stock and has control over all decisions requiring shareholder approval, including the election of our directors. In circumstances involving a conflict of interest between MEHC and our creditors and preferred stockholders, MEHC could exercise its control in a manner that would benefit MEHC to the detriment of our creditors and preferred stockholders.

Our Business Risks

We are subject to extensive regulations and legislation that affect our operations and costs. These regulations and laws are complex, dynamic and subject to change.

We are subject to numerous regulations and laws enforced by regulatory agencies. These regulatory agencies include, among others, the FERC, the WECC, the EPA and the public utility commissions in Utah, Oregon, Wyoming, Washington, Idaho and California.

Regulations affect almost every aspect of our business and limit our ability to independently make and implement management decisions regarding, among other items, constructing, acquiring or disposing of operating assets; business combinations; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; engaging in transactions between our subsidiaries and affiliates; and paying dividends. Regulations are subject to ongoing policy initiatives, and we cannot predict the future course of changes in regulatory laws, regulations and orders, or the ultimate effect that regulatory changes may have on us. However, such changes could adversely affect our consolidated financial results through higher capital expenditures and operating costs and an overall change in how we operate our business. For example, such changes could result in, but are not limited to, increased retail competition within our service territories; new environmental requirements, including the implementation of RPS and greenhouse gas ("GHG") emission reduction goals; the issuance of stricter air quality standards and the implementation of energy efficiency mandates; the acquisition by a municipality of our distribution facilities (by a vote in favor of a public utility district under state law or by condemnation, negotiation or legislation under state law); or a negative impact on our current cost recovery arrangements, including income tax recovery.

Federal and state energy regulation is one of the more challenging aspects of managing utility operations. The United States Congress and federal policy makers, with President Obama's support, are considering comprehensive climate change legislation such as the American Clean Energy and Security Act of 2009 ("Waxman-Markey bill") that was passed by the United States House of Representatives in June 2009. In addition to a federal renewable portfolio standard, which would require utilities to obtain a portion of their energy from certain qualifying renewable sources and energy efficiency measures, the bill requires a reduction in GHG emissions beginning in 2012, with emission reduction targets of 3% below 2005 levels by 2012; 17% below 2005 levels by 2020; 42% below 2005 levels by 2030; and 83% below 2005 levels by 2050 under a "cap and trade" program. In September 2009, a similar bill was introduced in the United States Senate by Senators Barbara Boxer and John Kerry, which would require an initial reduction in GHG emissions beginning in 2012 with emission reduction targets consistent with the Waxman-Markey bill, with the exception of the 2020 target, which requires 20% reduction below 2005 levels. In December 2009, the EPA issued a proposed determination that carbon dioxide ("CO_2") emissions can be regulated under the Clean Air Act and stated its intent to issue regulations limiting the release of CO_2 from sources including fossil fuel based electric generating facilities.

The impact of pending federal, regional, state and international accords, legislation or regulation related to climate change, including new laws, regulations or rules limiting GHG emissions could have a material adverse impact on us. We have significant coal-fired generating facilities that will be subject to more direct impacts and greater financial and regulatory risks. The impact is dependent on numerous factors, none of which can be quantified at this time. In addition to unknown factors, known factors include, but are not limited to, the magnitude and timing of GHG emissions reduction requirements; the cost, availability and effectiveness of emission control technology; the price and availability of offsets and allowances used for compliance; government-imposed compliance costs; and the existence and nature of incremental cost recovery mechanisms. To the extent that we are not allowed by regulators to recover or cannot otherwise recover the costs to comply with climate change requirements, these requirements could have a material adverse impact on our consolidated financial results. Additionally, even if such costs are recoverable in rates, if they are substantial and result in rates increasing to levels that substantially reduce sales volumes, this could have a material adverse impact on our consolidated financial results.

New and expanded regulations imposed by policy makers, court systems, and industry restructuring have imposed changes on the industry. The following are examples of recent changes to our regulatory environment that have impacted us:

- *Energy Policy Act of 2005* – The United States Energy Policy Act impacts many segments of the energy industry. The United States Congress granted the FERC additional authority in the Energy Policy Act which expanded its role from a regulatory body to an enforcement agency. To implement the law, the FERC adopted new regulations and issued regulatory decisions addressing electric system reliability, electric transmission planning, operation, expansion and pricing, regulation of utility holding companies, and enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation for noncompliance. The FERC has essentially completed its implementation of the Energy Policy Act, and the emphasis of its recent decisions is on reporting and compliance. In that regard, the FERC has vigorously exercised its enforcement authority by imposing significant civil penalties for violations of its rules and regulations. In addition, as a result of past events affecting electric reliability, the Energy Policy Act requires federal agencies, working together with non-governmental organizations charged with electric reliability responsibilities, to adopt and implement measures designed to ensure the reliability of electric transmission and distribution systems. Since the adoption of the Energy Policy Act, the FERC has approved numerous electric reliability and critical infrastructure protection standards developed by the NERC. A transmission owner's reliability compliance issues with these and future standards could result in financial penalties. In FERC Order No. 693, the FERC implemented its authority to impose penalties of up to $1 million per day per violation for failure to comply with electric reliability standards. The adoption of these and future electric reliability standards has imposed more comprehensive and stringent requirements on us, which has increased compliance costs. It is possible that the cost of complying with these and any additional standards adopted in the future could adversely affect our consolidated financial results.
- *FERC Orders* – The FERC has issued a series of orders to foster greater competition in wholesale power markets by reducing barriers to entry in the provision of transmission service. In FERC Order Nos. 888, 889 and 890, the FERC required electric utilities to adopt a pro forma OATT, by which transmission service would be provided on a just, reasonable and not unduly discriminatory or preferential basis. The rules adopted by these orders promote transparency and consistency in the administration of the OATT, increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent and coordinated transmission planning process. Together with the increased reliability standards required of transmission providers, the costs of operating the transmission system and providing transmission service have increased and, to the extent such increased costs are not recovered in rates charged to customers, they could adversely affect our consolidated financial results.
- *Hydroelectric Relicensing* – Currently, we are engaged in the FERC relicensing process for our Klamath hydroelectric system, for which the operating license has expired. We are currently operating under annual licenses. Through a settlement signed in February 2010 with relicensing stakeholders, disposition of the relicensing process and a path toward dam transfer and removal by a third party may occur as an alternative to relicensing. Hydroelectric relicensing is a political and public regulatory process involving sensitive resource issues and uncertainties. We cannot predict with certainty the requirements (financial, operational or otherwise) that may be imposed by relicensing, the economic impact of those requirements, and whether new licenses will ultimately be issued or whether we will be willing to meet the relicensing requirements to continue operating our hydroelectric generating facilities. Loss of hydroelectric resources or additional commitments arising from relicensing could adversely affect our consolidated financial results.

We are subject to numerous environmental, health, safety and other laws, regulations and other requirements that could adversely affect our consolidated financial results.

Operational Standards

We are subject to numerous environmental, health, safety and other laws, regulations and other requirements affecting many aspects of our present and future operations, including, among others:

- the EPA's Clean Air Interstate Rule ("CAIR"), which established cap-and-trade programs to reduce sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") emissions starting in 2009 to address alleged contributions to downwind non-attainment with the revised National Ambient Air Quality Standards;
- the implementation of federal and state RPS;
- other laws or regulations that establish or could establish standards for GHG emissions, water quality, wastewater discharges, solid waste and hazardous waste; and
- the provisions of the MINER Act to improve underground coal mine safety and emergency preparedness.

These and related laws, regulations and orders generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals.

Compliance with environmental, health, safety, and other laws, regulations and other requirements can require significant capital and operating expenditures, including expenditures for new equipment, inspection, cleanup costs, damages arising out of contaminated properties, and fines, penalties and injunctive measures affecting operating assets for failure to comply with environmental regulations. Compliance activities pursuant to regulations could be prohibitively expensive. As a result, some facilities may be required to shut down or alter their operations. Further, we may not be able to obtain or maintain all required environmental regulatory approvals for our operating assets or development projects. Delays in or active opposition by third parties to obtaining any required environmental or regulatory permits, failure to comply with the terms and conditions of the permits or increased regulatory or environmental requirements may increase costs or prevent or delay us from operating our facilities, developing new facilities, expanding existing facilities or favorably locating new facilities. If we fail to comply with all applicable environmental requirements, we may be subject to penalties and fines or other sanctions. The costs of complying with current or new environmental, health, safety and other laws, regulations and other requirements could adversely affect our consolidated financial results. Not being able to operate existing facilities or develop new electric generating facilities to meet customer energy needs could require us to increase our purchases of power from the wholesale markets which could increase market and price risks and adversely affect our consolidated financial results.

Proposals for voluntary initiatives and mandatory controls are being discussed both in the United States and worldwide, such as the December 2009 climate conference in Copenhagen, Denmark, to reduce greenhouse gases such as CO_2 (a by-product of burning fossil fuels) and methane (the primary component of natural gas). These actions could result in increased costs to (a) operate and maintain our facilities, (b) install new emission controls on our facilities and (c) administer and manage compliance with any GHG emissions program, such as through the purchase of emission credits as may be required. These actions could also increase the demand for natural gas, causing increased natural gas prices, thereby adversely affecting our operations. See the preceding risk titled, "We are subject to extensive regulations and legislation that affect our operations and costs. These regulations and laws are complex, dynamic and subject to change," for more detail on the United States' efforts and a discussion of the Waxman-Markey bill.

Site Cleanup and Contamination

Environmental, health, safety, and other laws, regulations and requirements also impose obligations to remediate contaminated properties or to pay for the cost of such remediation, often by parties that did not actually cause the contamination. We are generally responsible for on-site liabilities, and in some cases off-site liabilities, associated with the environmental condition of our assets, including power generating facilities and electric transmission and distribution assets that we have acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with acquisitions, we may obtain or require indemnification against some environmental liabilities. If we incur a material liability, or the other party to a transaction fails to meet its indemnification obligations, we could suffer material losses. We have established reserves to recognize our estimated obligations for known remediation liabilities, but such estimates may change materially over time. PacifiCorp is required to fund its portion of the costs of mine reclamation at its coal mining operations, which include principally site restoration. In addition, future events, such as changes in existing laws or policies or their enforcement, or the discovery of currently unknown contamination, may give rise to additional remediation liabilities that may be material.

Recovery of our costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect our consolidated financial results.

State Rate Proceedings

We establish rates for our regulated retail service through state regulatory proceedings. These proceedings typically involve multiple parties, including government bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns, but who generally have the common objective of limiting rate increases. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings.

Each state sets retail rates based in part upon the state utility commission's acceptance of an allocated share of total utility costs. When states adopt different methods to calculate interjurisdictional cost allocations, some costs may not be incorporated into rates of any state. Ratemaking is also generally done on the basis of estimates of normalized costs, so if a given year's realized costs are higher than normalized costs, rates will not be sufficient to cover those costs. Each state utility commission generally sets rates based on a test year established in accordance with that commission's policies. The test year data adopted by a regulatory commission may create a lag between the incurrence of a cost and its recovery in rates. They also decide the allowed levels of expense and investment that they deem are just and reasonable in providing service. The state regulatory commissions may disallow recovery in rates for any costs that do not meet such standard. State regulatory commissions also decide the allowed rate of return we will be given an opportunity to earn on our sources of capital.

In certain states, we are not permitted to pass through energy cost increases in our electric rates without a general rate case. Any significant increase in fuel costs for electricity generation or purchased power costs could have a negative impact on us, despite efforts to minimize this impact through future general rate cases or the use of hedging contracts. Any of these consequences could adversely affect our consolidated financial results.

While rate regulation is premised on providing a fair opportunity to obtain a reasonable rate of return on invested capital, the state regulatory commissions do not guarantee that we will be able to realize a reasonable rate of return.

FERC Jurisdiction

The FERC establishes cost-based rates under which we provide transmission services to wholesale markets and retail markets in states that allow retail competition. The FERC also has responsibility for approving both cost- and market-based rates under which we sell electricity at wholesale and has licensing authority over most of our hydroelectric generating facilities and has broad jurisdiction over energy markets. The FERC may impose price limitations, bidding rules and other mechanisms to address some of the volatility of these markets or may (pursuant to pending or future proceedings) revoke or restrict our ability to sell electricity at market-based rates, which could adversely affect our consolidated financial results. The FERC may also impose substantial civil penalties for any noncompliance with the Federal Power Act and the FERC's rules and orders.

We are actively pursuing, developing and constructing new or expanded facilities, the completion and expected cost of which are subject to significant risk, and we have significant funding needs related to our planned capital expenditures.

We are continuing to develop and construct new or expanded facilities. We expect to incur substantial annual capital expenditures over the next several years. Expenditures could include, among others, amounts for new electric generating facilities, electric transmission or distribution projects, environmental control and compliance systems, as well as the continued maintenance of the installed asset base.

Development and construction of major facilities are subject to substantial risks, including fluctuations in the price and availability of commodities, manufactured goods, equipment, labor and other items over a multi-year construction period, as well as the economic viability of our suppliers. These risks may result in higher than expected costs to complete an asset and place it in service. Such costs may not be recoverable in the regulated rates or market prices we are able to charge our customers. It is also possible that additional generation needs may be obtained through power purchase agreements, which could increase long-term purchase obligations and force reliance on the operating performance of a third party. The inability to successfully and timely complete a project, avoid unexpected costs or to recover any such costs could adversely affect our consolidated financial results.

Furthermore, we depend upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If we are unable to obtain funding from internal and external sources, we may need to postpone or cancel planned capital expenditures.

Failure to construct our planned projects could limit opportunities for revenue growth, increase operating costs and adversely affect the reliability of electric service to our customers. For example, if we are not able to expand our existing generating facilities, we may be required to enter into long-term electricity procurement contracts or procure electricity at more volatile and potentially higher prices in the spot markets to support growing retail loads.

A significant decrease in demand for electricity in the markets served by us would significantly decrease our operating revenue and thereby adversely affect our business and consolidated financial results.

A sustained decrease in demand for electricity in the markets served by us would significantly reduce our operating revenue and adversely affect our consolidated financial results. Factors that could lead to a decrease in market demand include, among others:

- a depression, recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on electricity, including the significant adverse changes in the economy and credit markets in 2008 and 2009 that may continue into future periods;
- an increase in the market price of electricity or a decrease in the price of other competing forms of energy;
- efforts by customers, legislators and regulators to reduce consumption of energy through various conservation and energy efficiency measures and programs;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of the fuel source for electricity generation or that limit the use of the generation of electricity from fossil fuels; and
- a shift to more energy-efficient or alternative fuel machinery or an improvement in fuel economy, whether as a result of technological advances by manufacturers, legislation mandating higher fuel economy or lower emissions, price differentials, incentives or otherwise.

We are subject to market risk, counterparty performance risk and other risks associated with wholesale energy markets.

In general, wholesale market risk is the risk of adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas and coal, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. Wholesale electricity prices may be influenced by several factors, such as the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind-powered generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth and changes in technology. Volumetric changes are caused by unanticipated changes in generation availability or changes in customer loads due to the weather, electricity prices, the economy, regulations or customer behavior. We purchase electricity and fuel in the open market or pursuant to short-term or variable-priced contracts as part of our normal operating business. If market prices rise, especially in a time when larger than expected volumes must be purchased at market or short-term prices, we may incur significantly greater expense than anticipated. Likewise, if electricity market prices decline in a period when we are a net seller of electricity in the wholesale market, we will earn less revenue.

We are also exposed to risks related to performance of contractual obligations by wholesale suppliers and customers. We rely on wholesale suppliers to deliver commodities, primarily natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure or delay by suppliers to provide these commodities pursuant to existing contracts could disrupt the delivery of electricity and require us to incur additional expenses to meet customer needs. In addition, when these contracts terminate, we may be unable to purchase the commodities on terms equivalent to the terms of current contracts.

We rely on wholesale customers to take delivery of the energy they have committed to purchase and to pay for the energy on a timely basis. Failure of customers to take delivery may require us to find other customers to take the energy at lower prices than the original customers committed to pay. At certain times of the year, prices paid by us for energy needed to satisfy our customers' energy needs may exceed the amounts we receive through rates. If our wholesale customers are unable to pay us for energy or fulfill their obligations, there may be a significant adverse impact on our cash flows. If the strategy used to minimize these risk exposures is ineffective or if our wholesale customers' financial condition deteriorates as a result of recent economic conditions causing them to be unable to pay, significant losses could result.

The deterioration in the credit quality of certain of our wholesale suppliers and customers as a result of the adverse economic conditions experienced in 2008 and 2009 could have an adverse impact on their ability to perform their contractual obligations, which in turn could have an adverse impact on our consolidated financial results.

Disruptions in the financial markets could affect our ability to obtain debt financing, draw upon or renew existing credit facilities, and have other adverse effects on us.

During 2008 and early 2009, the United States and global credit markets experienced historic dislocations and liquidity disruptions that caused financing to be unavailable in many cases. These circumstances materially impacted liquidity in the bank and debt capital markets during this period, making financing terms less attractive for borrowers who were able to find financing, and in other cases resulted in the unavailability of certain types of debt financing. In 2008 and 2009, the United States federal government enacted legislation in an attempt to stabilize the economy, increased the federal deposit insurance, invested billions of dollars in financial institutions and took other steps to infuse liquidity into the economy. The United States federal government Troubled Asset Relief Program ("TARP") and current accommodative monetary stance in the United States and most other industrialized countries have reduced liquidity concerns, relieved credit constraints and provided many financial institutions with the ability to strengthen their financial position. However, there is no certainty that the credit environment will improve and it is also possible that financial institutions may not be able to provide previously arranged funding under revolving credit facilities or other arrangements like those that we have established as potential sources of liquidity. It is also difficult to predict how the financial markets will react to the United States federal government's gradual withdrawal or removal of certain economic stimulus programs. Uncertainty in the credit markets may negatively impact our ability to access funds on favorable terms or at all. If we are unable to access the bank and debt markets to meet liquidity and capital expenditure needs, it may adversely affect the timing and amount of our capital expenditures, consolidated financial condition and results of operations.

We are exposed to credit risk of counterparties with whom we do business, and the failure of our significant customers to perform under or to renew their contracts, or failure to obtain new customers for expanded capacity, could adversely affect our consolidated financial results.

We rely on our wholesale customers to fulfill their commitments and pay for energy delivered to them on a timely basis. Adverse economic conditions or other events affecting counterparties with whom we conduct business could impair the ability of these counterparties to pay for services or fulfill their contractual obligations, or cause them to delay or reduce such payments. We depend on these counterparties to remit payments on a timely basis. Some suppliers and customers experienced deteriorating credit quality in 2008 and 2009, and we continue to monitor these parties to attempt to reduce the impact of any potential counterparty default. Any delay or default in payment or limitation to negotiate alternative arrangements could adversely affect our consolidated financial results.

If we are unable to renew, remarket, or find replacements for our long-term arrangements, our sales volumes and revenue would be exposed to reduction and increased volatility. Failure to maintain existing long-term agreements or secure new long-term agreements could adversely affect our consolidated financial results.

The replacement of any existing long-term agreements depends on market conditions and other factors that may be beyond our control.

Inflation and changes in commodity prices and fuel transportation costs may adversely affect our consolidated financial results.

Inflation may affect our business by increasing both operating and capital costs. As a result of existing rate agreements and competitive price pressures, we may not be able to pass the costs of inflation on to our customers. If we are unable to manage cost increases or pass them on to our customers, our consolidated financial results could be adversely affected.

We have a multitude of long-term agreements of varying duration that are material to the operation of our business, such as power purchase, coal and gas supply and transportation contracts. The failure to maintain, renew or replace these agreements on similar terms and conditions could increase our exposure to changes in prices, thereby increasing the volatility of our consolidated financial results. For example, we currently have contracts of varying durations for the supply and transportation of coal for much of our existing generation capacity, although we obtain some of our coal supply from mines owned or leased by us. When these contracts expire or if they are not honored, we may not be able to purchase or transport coal on terms as favorable as the current contracts. Changes in the cost of coal, natural gas, fuel oil and associated transportation costs and changes in the relationship between such costs and the market price of power will affect our consolidated financial results. Since the sales price we receive for power may not change at the same rate as our coal, natural gas, fuel oil and associated transportation costs, we may be unable to pass on the changes in these costs to our customers.

Our consolidated financial results may be adversely affected if we are unable to obtain adequate, reliable and affordable access to transmission service.

We depend on transmission facilities owned and operated by other utilities to transport electricity to both wholesale and retail markets, as well as natural gas purchased to supply some of our electric generating facilities. If adequate transmission is unavailable, we may be unable to purchase and sell and deliver electricity. A lack of availability could also hinder us from providing adequate or economical electricity to our wholesale and retail customers and could adversely affect our consolidated financial results.

The different regional power markets have varying and dynamic regulatory structures, which could affect our businesses' growth and performance. In addition, the independent system operators who oversee the transmission systems in regional power markets have imposed in the past, and may impose in the future, price limitations and other mechanisms to counter volatility in the power markets. These types of price limitations and other mechanisms may adversely affect our consolidated financial results.

Our operating results may fluctuate on a seasonal and quarterly basis and may be adversely affected by weather.

In the markets in which we operate, demand for electricity peaks during the hot summer months when irrigation and cooling needs are higher. Market prices for electric supply also generally peak at that time. In addition, demand for electricity generally peaks during the winter when heating needs are higher. Further, extreme weather conditions such as heat waves or winter storms could cause these seasonal fluctuations to be more pronounced. Periods of low rainfall or snowpack may also impact electric generation at our hydroelectric generating facilities.

As a result, our overall consolidated financial results may fluctuate substantially on a seasonal and quarterly basis. We have historically sold less power, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect our consolidated financial results through lower revenue or margins. Conversely, unusually extreme weather conditions could increase our costs to provide power and could adversely affect our consolidated financial results. Furthermore, during or following periods of low rainfall or snowpack, we may obtain substantially less electricity from hydroelectric generating facilities and must purchase greater amounts of electricity from the wholesale market or from other sources at market prices. Additionally, we have added substantial wind-powered generation capacity which is a climate dependent resource. The resulting variable production output that may at times affect the amount of energy available for sale or purchase. The extent of fluctuation in our consolidated financial results may change depending on a number of factors related to our regulatory environment and contractual agreements, including our ability to recover power costs and terms of the power sale contracts.

We are subject to operating uncertainties that could adversely affect our consolidated financial results.

The operation of complex electric utility (including generation, transmission and distribution) systems that are spread over large geographic areas involves many operating uncertainties and events beyond our control. These potential events include the breakdown or failure of power generation equipment, transmission and distribution lines or other equipment or processes; unscheduled generating facility outages; strikes, lockouts or other labor-related actions; shortage of qualified labor; transmission and distribution system constraints or outages; fuel shortages or interruptions; unavailability of critical equipment, materials and supplies; low water flows and other weather-related impacts; performance below expected levels of output, capacity or efficiency; operator error and catastrophic events such as severe storms, fires, earthquakes, explosions or mining accidents. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Any of these risks or other operational risks could significantly reduce or eliminate our revenue or significantly increase our expenses. For example, if we cannot operate generating facilities at full capacity due to damage caused by a catastrophic event, our revenue could decrease and our expenses could increase due to the need to obtain energy from more expensive sources. Further, we self-insure many risks and current and future insurance coverage may not be sufficient to replace lost revenue or cover repair and replacement costs. Any reduction of revenue for such reason, or any other reduction of our revenue or increase in our expenses resulting from the risks described above could adversely affect our consolidated financial results.

Potential terrorist activities or military or other actions could adversely affect our consolidated financial results.

The continued threat of terrorism since September 11, 2001 and the impact of military and other actions by the United States and its allies has led to increased political, economic and financial market instability and has subjected our operations to increased risks. The United States government has issued warnings that energy assets, specifically including electric utility infrastructure, are potential targets for terrorist organizations. Political, economic or financial market instability or damage to our operating assets or the assets of our customers or suppliers may result in business interruptions, lost revenue, higher commodity prices, disruption in fuel supplies, lower energy consumption and unstable markets, particularly with respect to electric energy, increased security, repair or other costs that may materially adversely affect us in ways that cannot be predicted at this time. Any of these risks could materially affect our consolidated financial results. Furthermore, instability in the financial markets as a result of terrorism or war could also materially adversely affect our ability to raise capital.

The insurance industry changed in response to these events. As a result, insurance covering risks we typically insure against may decrease in scope and availability and we may elect to self-insure against many such risks. In addition, the available insurance may have higher deductibles, higher premiums and more restrictive policy terms.

Poor performance of plan and fund investments and other factors impacting the pension and other postretirement benefit plans and mine reclamation trust funds could unfavorably impact our cash flows and liquidity.

Costs of providing our non-contributory defined benefit pension and other postretirement benefit plans depend upon a number of factors, including the rates of return on plan assets, the level and nature of benefits provided, discount rates, the interest rates used to measure required minimum funding levels, changes in benefit design, changes in laws and government regulation and our required or voluntary contributions made to the plans. Our pension and other postretirement benefit plans are in underfunded positions. Even with sustained growth in the investments over future periods to increase the value of these plans' assets, we will likely be required to make significant cash contributions to fund these plans. Furthermore, the Pension Protection Act of 2006, as amended, may result in more volatility in the amount and timing of future contributions. Similarly, funds dedicated to mine reclamation are also invested in equity and fixed income securities and poor performance of these investments will reduce the amount of funds available for their intended purpose which would require us to make additional cash contributions. Such cash funding obligations, which are also impacted by the other factors described above, could have a material impact on our liquidity by reducing our cash flows.

We are involved in numerous legal proceedings, the outcomes of which are uncertain and could adversely affect our consolidated financial results.

We are party to numerous legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters. It is possible that the final resolution of some of the matters in which we are involved could result in additional payments in excess of established reserves over an extended period of time and in amounts that could have a material adverse effect on our consolidated financial results. Similarly, it is also possible that the terms of resolution could require that we change business practices and procedures, which could also have a material adverse effect on our consolidated financial results. Further, litigation could result in the imposition of financial penalties or injunctions which could limit our ability to take certain desired actions or the denial of needed permits, licenses or regulatory authority to conduct our business, including the siting or permitting of facilities. Any of these outcomes could adversely affect our consolidated financial results. In addition to legal proceedings to which we are party, it is possible that outcomes of GHG litigation involving others in our industry could impact our business through additional environmental regulatory requirements.

Potential changes in accounting standards may impact our consolidated financial results and disclosures in the future, which may change the way analysts measure our business or financial performance.

The Financial Accounting Standards Board ("FASB") and the SEC continuously make changes to accounting standards and disclosure and other financial reporting requirements. New or revised accounting standards and requirements issued by the FASB or the SEC or new accounting orders issued by the FERC could significantly impact our consolidated financial results and disclosures.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

PacifiCorp's properties consist of the physical assets necessary to support its electricity business, which include electric generation, transmission and distribution facilities, as well as coal mining assets that support certain of PacifiCorp's electric generating facilities. In addition to these physical assets, PacifiCorp has rights-of-way, mineral rights and water rights that enable PacifiCorp to utilize its facilities. It is the opinion of PacifiCorp's management that the principal depreciable properties owned by PacifiCorp are in good operating condition and are well maintained. Substantially all of PacifiCorp's electric utility properties are subject to the lien of PacifiCorp's Mortgage and Deed of Trust. Refer to Exhibit 4.1 in Item 15 of this Form 10-K. For additional information regarding PacifiCorp's energy properties, refer to Item 1 of this Form 10-K and Notes 3 and 4 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

The right to construct and operate PacifiCorp's electric transmission and distribution facilities across certain property was obtained in most circumstances through negotiations and, where necessary, through the exercise of the power of eminent domain. PacifiCorp continues to have the power of eminent domain in each of the jurisdictions in which it operates, but it does not have the power of eminent domain with respect to Native American tribal lands.

With respect to real property, each of the transmission and distribution facilities fall into two basic categories: (a) parcels that are owned in fee, such as certain of PacifiCorp's generating facilities, substations and office sites; and (b) parcels where the interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for the construction, operation and maintenance of the transmission and distribution facilities. PacifiCorp believes that it has satisfactory title to all of the real property making up its respective facilities in all material respects.

Headquarters/Offices

PacifiCorp's corporate offices consist of approximately 800,000 square feet of owned and leased office space located in several buildings in Portland, Oregon and Salt Lake City, Utah. PacifiCorp's corporate headquarters are in Portland, but there are several executives and departments located in Salt Lake City. In addition to the corporate headquarters, PacifiCorp owns and leases approximately 1 million square feet of field office and warehouse space in various other locations in Utah, Oregon, Wyoming, Washington, Idaho and California. The field location square footage does not include offices located at PacifiCorp's generating facilities.

Item 3. Legal Proceedings

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material effect on its consolidated financial results. PacifiCorp is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts and are described below.

In December 2000, Wah Chang, a large industrial customer of PacifiCorp that operates a reactive and refractory metals manufacturing facility in Millersburg, Oregon, filed an action before the OPUC asserting that the rates set by a special tariff with PacifiCorp and approved by the OPUC were not just and reasonable. In October 2001, the OPUC dismissed Wah Chang's petition and found that Wah Chang assumed the risk of price increases under the special tariff. Wah Chang petitioned the Circuit Court for Marion County, Oregon for review of the OPUC's order. In June 2002, the Circuit Court for Marion County, Oregon, granted Wah Chang's motion and ordered the OPUC to reopen the record to allow Wah Chang the opportunity to present new evidence of alleged market manipulation during the energy crisis. In September 2009, the OPUC dismissed Wah Chang's petition and reaffirmed that the rates set by the special tariff were just and reasonable. In October 2009, Wah Chang filed with the Oregon Court of Appeals a petition for judicial review of the OPUC's September 2009 order denying Wah Chang relief.

In a separate but related proceeding, in December 2000, Wah Chang filed a complaint in the Circuit Court for Linn County, Oregon, asserting that the special tariff with PacifiCorp is subject to rescission based on theories of mutual mistake of fact, frustration of purpose and impracticability. In August 2002, the Circuit Court for Linn County, Oregon, granted PacifiCorp's motion for summary judgment dismissing Wah Chang's complaint. In February 2004, the Circuit Court for Linn County, Oregon, granted Wah Chang's motion to reopen the case to present additional evidence of alleged market manipulation. In December 2007, Wah Chang filed a second amended complaint seeking recovery of a portion of the costs paid under the special tariff based on various theories of legal relief, including partial rescission, unjust enrichment, and breach of duty of good faith and fair dealing. In August 2009, the Circuit Court for Linn County, Oregon, granted Wah Chang's request to file a third amended complaint containing a claim for punitive damages. In December 2009, PacifiCorp's motion for summary judgment based on the OPUC's September 2009 order was denied by the Circuit Court for Linn County, Oregon. The trial date has been stayed until 2011. Wah Chang is seeking $37 million (less the amount Wah Chang would have paid for electricity absent the special tariff) in compensatory damages and $200 million in punitive damages. PacifiCorp intends to vigorously defend these claims and believes that the outcome of these proceedings will not have a material impact on its consolidated financial results.

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Wyoming state opacity standards at PacifiCorp's Jim Bridger generating facility in Wyoming. Under Wyoming state requirements, which are part of the Jim Bridger generating facility's Title V permit and are enforceable by private citizens under the federal Clean Air Act, a potential source of pollutants such as a coal-fired generating facility must meet minimum standards for opacity, which is a measurement of light that is obscured in the flue of a generating facility. The complaint alleged thousands of violations of asserted six-minute compliance periods and sought an injunction ordering the Jim Bridger generating facility's compliance with opacity limits, civil penalties of $32,500 per day per violation and the plaintiffs' costs of litigation. In August 2009, the court ruled on a number of summary judgment motions by which it determined that the plaintiffs have sufficient legal standing to proceed with their complaint and that all other issues raised in the summary judgment motions will be resolved at trial. In February 2010, PacifiCorp, the Sierra Club and the Wyoming Outdoor Council reached an agreement in principle to settle all outstanding claims in the action. The settlement will be memorialized in a consent decree to be filed with the Environmental Protection Agency for review and also with the court for review and approval. If approved by the court as expected, the settlement is not expected to have a material impact on PacifiCorp's consolidated financial results.

In October 2005, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in state district court in Salt Lake City, Utah by USA Power, LLC and its affiliated companies, USA Power Partners, LLC and Spring Canyon, LLC (collectively, "USA Power"), against Utah attorney Jody L. Williams and the law firm Holme, Roberts & Owen, LLP, who represent PacifiCorp on various matters from time to time. USA Power was the developer of a planned generation project in Mona, Utah called Spring Canyon, which PacifiCorp, as part of its resource procurement process, at one time considered as an alternative to the Currant Creek generating facility. USA Power's complaint alleged that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accused PacifiCorp of breach of contract and related claims. USA Power seeks $250 million in damages, statutory doubling of damages for its trade secrets violation claim, punitive damages, costs and attorneys' fees. After considering various motions for summary judgment, the court ruled in October 2007 in favor of PacifiCorp on all counts and dismissed the plaintiffs' claims in their entirety. In February 2008, the plaintiffs filed a petition requesting consideration of their appeal by the Utah Supreme Court. The plaintiffs' request was granted and they filed a brief in November 2008 with the Utah Supreme Court. In January 2009, PacifiCorp filed its reply brief. PacifiCorp believes that its defenses that prevailed in the trial court will prevail on appeal. Furthermore, PacifiCorp expects that the outcome of any appeal will not have a material impact on its consolidated financial results.

Item 4. Reserved

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

MEHC indirectly owns all of the shares of PacifiCorp's outstanding common stock. Therefore, there is no public market for PacifiCorp's common stock. PacifiCorp did not pay dividends on common stock during the years ended December 31, 2009 and 2008. PacifiCorp does not expect to declare or pay dividends on common stock during the year ending December 31, 2010.

During the years ended December 31, 2009 and 2008, PacifiCorp received capital contributions of $125 million and $450 million, respectively, in cash from its indirect parent company, MEHC.

For a discussion of regulatory restrictions that limit PacifiCorp's ability to pay dividends on common stock, refer to "Limitations" in Item 7 and Note 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Item 6. Selected Financial Data

The following table sets forth PacifiCorp's selected consolidated historical financial data, which should be read in conjunction with Item 7 of this Form 10-K and with PacifiCorp's historical Consolidated Financial Statements and notes thereto in Item 8 of this Form 10-K. The selected consolidated historical financial data has been derived from PacifiCorp's audited historical Consolidated Financial Statements and notes thereto (in millions). In May 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year-end from March 31 to December 31.

	Years Ended December 31,			Nine-Month Period Ended December 31,	Year Ended March 31,
	2009	2008	2007	2006	2006
Consolidated Statement of Operations Data:					
Operating revenue	$ 4,457	$ 4,498	$ 4,258	$ 2,924	$ 3,897
Operating income	1,060	954	894	421	802
Net income attributable to PacifiCorp	542	458	439	161	361

	As of December 31,				As of March 31,
	2009	2008	2007	2006	2006
Consolidated Balance Sheet Data:					
Total assets	$ 18,966	$ 17,167	$ 14,907	$ 13,852	$ 12,731
Long-term debt and capital lease obligations, excluding current portion	6,400	5,424	4,753	3,967	3,721
Preferred stock subject to mandatory redemption, excluding current portion	-	-	-	-	41
Preferred stock	41	41	41	41	41
Total PacifiCorp shareholders' equity	6,648	5,987	5,080	4,426	4,052

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the financial condition and results of operations of PacifiCorp during the periods included herein. Explanations include management's best estimate of the impacts of weather, customer growth and other factors. This discussion should be read in conjunction with Item 6 of this Form 10-K and with PacifiCorp's historical Consolidated Financial Statements and notes thereto in Item 8 of this Form 10-K. PacifiCorp's actual results in the future could differ significantly from the historical results.

Results of Operations

Operating revenue and energy costs are the key drivers of PacifiCorp's results of operations as they encompass retail and wholesale electricity sales and the direct costs associated with providing electricity for our customers. PacifiCorp believes that a discussion of gross margin, representing operating revenue less energy costs, is therefore most meaningful. PacifiCorp serves its customers with electricity supplied by its generating facilities, as well as through wholesale electricity purchases as needed to meet its retail load and long-term wholesale sales obligations. PacifiCorp also sells electricity in the wholesale market to balance its system and to enhance the utilization of its generating capacity.

Overview

Net income attributable to PacifiCorp during the year ended December 31, 2009 was $542 million, an increase of $84 million, or 18%, as compared to 2008. Net income attributable to PacifiCorp increased primarily due to improved gross margin of $239 million resulting from significantly lower average prices and decreased volumes of wholesale electricity purchases, higher prices approved by regulators on retail electricity sales and sales of renewable energy credits, partially offset by significantly lower average prices on wholesale electricity sales and lower retail customer usage. Retail energy sales volumes decreased 3%, primarily due to the impacts of the current economic conditions on industrial customers across PacifiCorp's service territories and residential customers in Oregon. Depreciation expense increased $59 million and interest expense increased $51 million mainly due to higher assets placed in service and the issuance of long-term debt to finance those assets.

PacifiCorp experienced more flexibility in balancing its system requirements during 2009 and the fourth quarter of 2008 due to the September 2008 acquisition of the 520-MW Chehalis natural gas-fired generating facility. From May 2008 through September 2009, PacifiCorp also placed in service 647 MWs of wind-powered generating facilities. Overall lower retail demand experienced in 2009 and the fourth quarter of 2008, along with the increased generation capacity, reduced PacifiCorp's reliance on wholesale electricity purchases.

Net income attributable to PacifiCorp during the year ended December 31, 2008 was $458 million, an increase of $19 million, or 4%, as compared to 2007. Net income attributable to PacifiCorp increased primarily due to improved gross margin of $51 million resulting from higher prices approved by regulators on retail electricity sales, lower volumes of wholesale electricity purchases, higher average prices on wholesale electricity sales and growth in the average number of residential and commercial customers, largely offset by higher average fuel prices, higher average prices on wholesale electricity purchases and lower volumes of wholesale electricity sales. Interest expense increased $29 million, primarily due to the issuance of long-term debt in support of PacifiCorp's capital expenditures program. Income tax expense increased $18 million, primarily due to higher pre-tax earnings, partially offset by higher production tax credits associated with increased production at wind-powered generating facilities.

As discussed in Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K, PacifiCorp adopted authoritative guidance that established accounting and reporting standards for the noncontrolling interest in a subsidiary as of January 1, 2009. The new guidance impacted PacifiCorp's presentation of both revenue and expense associated with the noncontrolling interest in its majority owned coal mining operation and had no impact on net income attributable to PacifiCorp.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

A comparison of PacifiCorp's key operating results were as follows for the years ended December 31:

			Favorable/(Unfavorable)	
	2009	2008	Change	% Change
Gross margin (in millions):				
Operating revenue	$ 4,457	$ 4,498	$ (41)	(1)%
Energy costs	1,677	1,957	280	14
Gross margin	$ 2,780	$ 2,541	$ 239	9%
Volumes of electricity sold (in gigawatt hours ("GWh")):				
Residential	15,999	16,222	(223)	(1)%
Commercial	16,194	16,055	139	1
Industrial	19,934	21,495	(1,561)	(7)
Other	583	590	(7)	(1)
Total retail electricity sales	52,710	54,362	(1,652)	(3)
Wholesale electricity sales	12,349	12,345	4	-
Total electricity sales	65,059	66,707	(1,648)	(2)%
Retail electricity sales:				
Average retail customers (in thousands)	1,719	1,706	13	1%
Average revenue per MWh	$ 66.74	$ 63.44	$ 3.30	5%
Wholesale electricity sales:				
Average revenue per MWh	$ 51.95	$ 68.78	$ (16.83)	(24)%
Volumes of electricity generated (in GWh):				
Coal-fired generation	43,854	45,955	(2,101)	(5)%
Natural gas-fired generation	8,576	8,771	(195)	(2)
Hydroelectric generation [1]	3,544	3,766	(222)	(6)
Other	2,427	1,386	1,041	75
Total PacifiCorp generated volumes	58,401	59,878	(1,477)	(2)%
Volumes of electricity purchased (in GWh):				
Wholesale electricity purchases	10,975	11,448	473	4%
Cost of wholesale electricity purchased:				
Average cost per MWh	$ 42.95	$ 66.56	$ 23.61	35%

(1) PacifiCorp's hydroelectric generation was 85% and 90% of normal for 2009 and 2008, respectively, based on a 30-year average.

Gross margin increased $239 million, or 9%, primarily due to:

- $134 million of increases from higher retail prices approved by regulators primarily to recover increased costs of assets placed in service and higher energy costs;
- $83 million of increases in net wholesale electricity activities due to $259 million of significantly lower average prices on wholesale electricity purchases and $32 million of lower volumes of wholesale electricity purchases, partially offset by $208 million of lower average prices on wholesale electricity sales;
- $66 million of increases due to sales to the noncontrolling interest in PacifiCorp's majority owned coal mining operation;
- $44 million of increases in sales of renewable energy credits;
- $27 million of increases due to growth in the average number of commercial and residential customers primarily in Utah; and
- $13 million of decreases in fuel costs primarily due to lower volumes of coal consumed as a result of increased generating facility overhauls and lower retail demand, partially offset by higher average prices of coal.

These increases in gross margin were partially offset by:

- $92 million of decreases due to lower average customer usage primarily in Oregon and on industrial customers across PacifiCorp's service territories due to the effects of the current economic conditions; and
- $26 million due to lower deferrals of incurred power costs in accordance with established adjustment mechanisms.

Operations and maintenance expense increased $50 million, or 5%, primarily due to costs associated with sales to the noncontrolling interest in PacifiCorp's majority owned coal mining operation.

Depreciation and amortization expense increased $59 million, or 12%, primarily due to higher plant-in-service.

Taxes, other than income taxes increased $24 million, or 21%, primarily due to costs attributable to PacifiCorp's majority owned coal mining operation and increased property taxes driven by higher plant-in-service.

Interest expense increased $51 million, or 15%, primarily due to higher average debt outstanding, partially offset by lower average rates on variable- and fixed-rate debt.

Allowance for borrowed and equity funds increased $18 million, or 22%, primarily due to higher qualified construction work-in-progress balances, partially offset by lower average rates.

Interest income increased $8 million, or 73%, substantially due to interest associated with PacifiCorp's 2006 and 2007 tax reports pursuant to SB 408.

Income tax expense decreased $4 million to $234 million for the year ended December 31, 2009 as compared to 2008, primarily due to higher production tax credits associated with increased production at wind-powered generating facilities, substantially offset by higher pre-tax earnings. The effective tax rate was 30% for the year ended December 31, 2009 compared to 34% for the year ended December 31, 2008.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

A comparison of PacifiCorp's key operating results were as follows for the years ended December 31:

	2008	2007	Favorable/(Unfavorable) Change	% Change
Gross margin (in millions):				
Operating revenue	$ 4,498	$ 4,258	$ 240	6%
Energy costs	1,957	1,768	(189)	(11)
Gross margin	$ 2,541	$ 2,490	$ 51	2%
Volumes of electricity sold (in GWh):				
Residential	16,222	15,975	247	2%
Commercial	16,055	15,951	104	1
Industrial	21,495	20,892	603	3
Other	590	572	18	3
Total retail electricity sales	54,362	53,390	972	2
Wholesale electricity sales	12,345	13,724	(1,379)	(10)
Total electricity sales	66,707	67,114	(407)	(1)%
Retail electricity sales:				
Average retail customers (in thousands)	1,706	1,684	22	1%
Average revenue per MWh	$ 63.44	$ 60.90	$ 2.54	4%
Wholesale electricity sales:				
Average revenue per MWh	$ 68.78	$ 60.91	$ 7.87	13%
Volumes of electricity generated (in GWh):				
Coal-fired generation	45,955	45,700	255	1%
Natural gas-fired generation	8,771	7,915	856	11
Hydroelectric generation (1)	3,766	3,748	18	-
Other	1,386	829	557	67
Total PacifiCorp generated volumes	59,878	58,192	1,686	3%
Volumes of electricity purchased (in GWh):				
Wholesale electricity purchases	11,448	13,587	2,139	16%
Cost of wholesale electricity purchased:				
Average cost per MWh	$ 66.56	$ 58.64	$ (7.92)	(14)%

(1) PacifiCorp's hydroelectric generation was 90% of normal for both 2008 and 2007, based on a 30-year average.

Gross margin increased $51 million, or 2%, primarily due to:

- $129 million of increases from higher retail prices approved by regulators primarily to recover increased costs of assets placed in service and higher energy costs;
- $69 million of increases in retail electricity sales due to $48 million related to growth in the average number of retail residential and commercial customers and $21 million related to higher average retail customer usage;
- $48 million of increases in net wholesale electricity activities due to $126 million of lower volumes of wholesale electricity purchases and $98 million of higher average prices on wholesale electricity sales, partially offset by $91 million of higher average prices on wholesale electricity purchases and $85 million of lower volumes of wholesale electricity sales; and
- $19 million of increases in transmission revenue primarily due to higher contract prices.

These increases in gross margin were partially offset by:

- $182 million of increases in fuel costs due to $141 million of natural gas and $41 million of coal cost increases substantially due to higher average prices;
- $27 million of increases primarily due to the amortization of incurred power costs deferred in the prior year in accordance with established adjustment mechanisms; and
- $15 million of increases in transmission costs primarily due to new contracts.

Operations and maintenance expense decreased $13 million, or 1%, primarily due to:

- $27 million of decreases in employee expenses, substantially due to lower pension and other postretirement benefit expenses; partially offset by,
- $10 million of increases in DSM expense primarily due to increased spending in Oregon and Idaho; and
- $5 million of increases in bad debt expense, primarily in the commercial and industrial customer classes as a result of economic conditions.

Depreciation and amortization expense decreased $7 million, or 1%, primarily due to a $47 million reduction from the extension of the depreciable lives of certain property, plant and equipment as a result of PacifiCorp's 2008 depreciation study, substantially offset by higher assets placed in service.

Taxes, other than income taxes increased $11 million, or 11%, primarily due to increased property taxes driven by increased levels of assessable property.

Interest expense increased $29 million, or 9%, primarily due to higher average debt outstanding, partially offset by lower average rates on variable-rate debt.

Allowance for borrowed and equity funds increased $11 million, or 16%, primarily due to higher qualified construction work-in-progress balances, partially offset by lower average rates.

Income tax expense increased $18 million to $238 million for the year ended December 31, 2008 as compared to 2007, primarily due to higher pre-tax earnings, partially offset by higher production tax credits associated with increased production at wind-powered generating facilities. The effective tax rate was 34% for the year ended December 31, 2008 compared to 33% for the year ended December 31, 2007.

Liquidity and Capital Resources

As of December 31, 2009, PacifiCorp's total net liquidity available was $1.254 billion. The components of total net liquidity available are as follows (in millions):

Cash and cash equivalents	$ 117
Available revolving credit facilities	$ 1,395
Less:	
Short-term debt (credit facility borrowings or commercial paper)	-
Tax-exempt bond support and letters of credit	(258)
Net revolving credit facilities available	$ 1,137
Total net liquidity available	$ 1,254
Unsecured revolving credit facilities:	
Maturity date	2012-2013
Largest single bank commitment as a % of total [(1)]	15%

(1) An inability of financial institutions to honor their commitments could adversely affect PacifiCorp's short-term liquidity and ability to meet long-term commitments.

PacifiCorp's cash and cash equivalents were $117 million as of December 31, 2009, compared to $59 million as of December 31, 2008. PacifiCorp has restricted cash and investments included in other current assets and investments and other assets on the Consolidated Balance Sheets totaling $88 million and $93 million as of December 31, 2009 and 2008, respectively that principally relate to funds held in trust for coal mine reclamation.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2009 and 2008 were $1.5 billion and $992 million, respectively. The $508 million increase was primarily due to significantly lower average prices on wholesale electricity purchases, higher prices approved by regulators principally to recover prior years' investments in capital projects, significantly higher income tax deductions related to the impact of the repairs deduction and bonus depreciation, and net receipts of cash collateral on derivative contracts in the current year compared to net postings of cash collateral in the prior year, partially offset by lower average prices on wholesale sales.

Net cash flows from operating activities for the years ended December 31, 2008 and 2007 were $992 million and $824 million, respectively. The $168 million increase was primarily due to higher margins resulting from higher prices approved by regulators principally to recover increased costs of assets placed in service and higher energy costs, and higher income tax deductions driven by the impact of bonus depreciation, partially offset by higher fuel costs primarily due to higher average prices on natural gas and increased net postings of cash collateral on derivative contracts.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2009 and 2008 were $(2.308) billion and $(2.076) billion, respectively. Capital expenditures increased $539 million primarily due to construction costs for the Populus-to-Terminal transmission line, partially offset by the September 2008 acquisition of Chehalis Power Generating, LLC, an entity owning a 520-MW natural gas-fired generating facility located in Chehalis, Washington, for $308 million. Chehalis Power Generating, LLC was merged into PacifiCorp immediately following the acquisition.

Net cash flows from investing activities for the years ended December 31, 2008 and 2007 were $(2.076) billion and $(1.497) billion, respectively. The $579 million increase was primarily due to a $270 million increase in capital expenditures and PacifiCorp's $308 million acquisition of Chehalis Power Generating, LLC.

Capital Expenditures

Capital expenditures, excluding the non-cash allowance for equity funds used during construction ("equity AFUDC"), consisted mainly of the following during the years ended December 31:

2009

- Transmission system investments totaling $748 million, including costs for the construction of a 135-mile, double-circuit, 345-kilovolt transmission line to be built between the Populus substation in southern Idaho and the Terminal substation near Salt Lake City, Utah, the first major segment of the Energy Gateway Transmission Expansion Program.
- The development and construction of wind-powered generating facilities totaling $407 million, including 218 MW placed in service in December 2008, 138 MW placed in service in January 2009 and 127 MW placed in service in September 2009. The expenditures also included construction costs for the 111-MW Dunlap Ranch I wind-powered generating facility expected to be placed in service in 2010.
- Emission control equipment totaling $345 million, including the installation costs for emission control equipment under construction at the Dave Johnston generating facility related to the addition of a new sulfur dioxide scrubber on Unit 3 and the replacement of an existing sulfur dioxide scrubber on Unit 4, which are expected to be placed into service during 2010 and 2012, respectively. Additional projects included installation of sulfur dioxide scrubbers on Naughton generating facility Units 1 and 2.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected growing demand totaling $828 million.

2008

- The development and construction of wind-powered generating facilities totaling $600 million, including the remaining costs for five wind-powered generating facilities totaling 382 MW placed in service during the year ended December 31, 2008. The expenditures also included the construction costs for three wind-powered generating facilities that were placed in service in 2009.
- Emission control equipment totaling $204 million, including the remaining installation costs for emission control equipment placed in service at the Cholla generating facility in May 2008 and emission control equipment under construction at the Dave Johnston generating facility.
- Transmission system investments totaling $234 million, including costs for the Populus-to-Terminal transmission line.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected growing demand totaling $751 million.

Financing Activities

Short-Term Debt and Revolving Credit Agreements

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. PacifiCorp had no short-term debt outstanding as of December 31, 2009 compared to $85 million outstanding as of December 31, 2008 at a weighted-average interest rate of 1%. The decrease in short-term debt was primarily due to the proceeds from the issuance of long-term debt and $125 million of capital contributions received from MEHC during the period, partially offset by capital expenditures and maturities of long-term debt in excess of net cash provided by operating activities.

PacifiCorp had no outstanding borrowings under its unsecured revolving credit facilities as of December 31, 2009 or 2008. However, any disruptions in the credit markets may result in increased costs of commercial paper and limit the ability of PacifiCorp to issue commercial paper, which may lead to higher reliance on its unsecured revolving credit facilities for short-term liquidity purposes.

For further discussion, refer to Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Long-Term Debt

In addition to the debt issuances discussed herein, PacifiCorp made scheduled repayments on long-term debt totaling $138 million and $412 million during the years ended December 31, 2009 and 2008, respectively.

In January 2009, PacifiCorp issued $350 million of its 5.50% First Mortgage Bonds due January 15, 2019 and $650 million of its 6.00% First Mortgage Bonds due January 15, 2039. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes.

In July 2008, PacifiCorp issued $500 million of its 5.65% First Mortgage Bonds due July 15, 2018 and $300 million of its 6.35% First Mortgage Bonds due July 15, 2038.

In September 2008, PacifiCorp acquired $216 million of its insured variable-rate tax-exempt bond obligations due to the significant reduction in market liquidity for insured variable-rate obligations. In November 2008, the associated insurance and related standby bond purchase agreements were terminated and these variable-rate long-term debt obligations were remarketed with credit enhancement and liquidity support provided by $220 million of letters of credit issued under PacifiCorp's two unsecured revolving credit facilities.

As of December 31, 2009, PacifiCorp had $517 million of letters of credit available to provide credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $504 million plus interest. These committed bank arrangements were fully available at December 31, 2009 and expire periodically through May 2012.

PacifiCorp has regulatory authority from the OPUC to issue an additional $2.0 billion of long-term debt. Current authority from the IPUC would permit $200 million of additional long-term debt issuances, and PacifiCorp is currently seeking authority for a total of $2.0 billion. PacifiCorp must make a notice filing with the WUTC prior to any future issuance.

PacifiCorp's Mortgage and Deed of Trust creates a lien on most of PacifiCorp's electric utility property, allowing the issuance of bonds based on a percentage of utility property additions, bond credits arising from retirement of previously outstanding bonds or deposits of cash. The amount of bonds that PacifiCorp may issue generally is also subject to a net earnings test. As of December 31, 2009, PacifiCorp estimated it would be able to issue up to $5.5 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

PacifiCorp may from time to time seek to acquire its outstanding debt securities through cash purchases in the open market, privately negotiated transactions or otherwise. Any debt securities repurchased by PacifiCorp may be reissued or resold by PacifiCorp from time to time and will depend on prevailing market conditions, PacifiCorp's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Common Shareholder's Equity

Cash capital contributions from PacifiCorp's indirect parent company, MEHC, were $125 million and $450 million during the years ended December 31, 2009 and 2008, respectively.

Capitalization

PacifiCorp manages its capitalization and liquidity position to maintain a prudent capital structure with an objective of retaining strong investment grade credit ratings, which is expected to facilitate continuing access to flexible borrowing arrangements at favorable costs and rates. This objective, subject to periodic review and revision, attempts to balance the interests of all shareholders, customers and creditors and provide a competitive cost of capital and predictable capital market access.

As a result of authoritative accounting guidance, such as guidance pertaining to consolidations and leases, it is possible that new purchase power and gas agreements, transmission arrangements or amendments to existing arrangements may be accounted for as capital lease obligations or debt on PacifiCorp's financial statements. While PacifiCorp has successfully amended covenants in financing arrangements that may be impacted by these changes, it may be more difficult for PacifiCorp to comply with its capitalization targets or regulatory commitments concerning minimum levels of common equity as a percentage of capitalization. This may lead PacifiCorp to seek amendments or waivers under financing agreements and from regulators, delay or reduce dividends or spending programs, seek additional new equity contributions from its indirect parent company, MEHC, or take other actions.

Future Uses of Cash

PacifiCorp has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, capital contributions and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which PacifiCorp has access to external financing depends on a variety of factors, including PacifiCorp's credit rating, investors' judgment of risk and conditions in the overall capital market, including the condition of the utility industry in general.

During 2008 and early 2009, the United States and global credit markets experienced historic dislocations and liquidity disruptions that caused financing to be unavailable in many cases. These circumstances materially impacted liquidity in the bank and debt capital markets during this period, making financing terms less attractive for borrowers who were able to find financing, and in other cases resulted in the unavailability of certain types of debt financing. In 2008 and 2009, the United States federal government enacted legislation in an attempt to stabilize the economy, increased the federal deposit insurance, invested billions of dollars in financial institutions and took other steps to infuse liquidity into the economy. The United States federal government TARP and the current accommodative monetary stance in the United States and most other industrialized countries have reduced liquidity concerns, relieved credit constraints and provided many financial institutions with the ability to strengthen their financial position. However, there is no certainty that the credit environment will improve and it is also possible that financial institutions may not be able to provide previously arranged funding under revolving credit facilities or other arrangements like those that PacifiCorp has established as potential sources of liquidity. It is also difficult to predict how the financial markets will react to the United States federal government's gradual withdrawal or removal of certain economic stimulus programs. Uncertainty in the credit markets may negatively impact PacifiCorp's ability to access funds on favorable terms or at all. If PacifiCorp is unable to access the bank and debt markets to meet liquidity and capital expenditure needs it may adversely affect the timing and amount of PacifiCorp's capital expenditures, consolidated financial condition and results of operations.

Capital Expenditures

PacifiCorp has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in rules and regulations, including environmental; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; and the cost and availability of capital. Expenditures for compliance-related items such as pollution control technologies, replacement generation, mine reclamation, hydroelectric relicensing, hydroelectric decommissioning and associated operating costs are generally incorporated into PacifiCorp's regulated retail rates.

PacifiCorp estimates that it will spend approximately $4.6 billion on capital projects over the next three years, excluding non-cash equity AFUDC. These capital projects include new generating resources, including renewables; transmission investments; installation of emissions control equipment on existing generating facilities; and distribution investments in new connections, lines and substations.

Forecasted capital expenditures are as follows for the years ended December 31 (in millions):

	2010	2011	2012
Forecasted capital expenditures (1):			
Generation development	$ 180	$ 18	$ 232
Transmission system investment	451	423	667
Environmental	334	252	119
Other	660	679	558
Total	$ 1,625	$ 1,372	$ 1,576

(1) Excludes amounts for non-cash equity AFUDC.

The capital expenditure estimate for generation development projects provided above for the year ending December 31, 2010 includes $153 million for the remaining construction costs associated with the 111-MW Dunlap Ranch I wind-powered generating facility that is expected to be placed in service during 2010.

Capital projects for transmission expansion include the Energy Gateway Transmission Expansion Program, a plan to build approximately 2,000 miles of new high-voltage transmission lines, with an estimated cost exceeding $6 billion, primarily in Wyoming, Utah, Idaho, Oregon and the desert Southwest. The plan includes several transmission line segments that will: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse resource areas, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area and the Western United States. Proposed transmission line segments are re-evaluated to ensure maximum benefits and timing before commitments to move forward with permitting and construction are made. The first major transmission segments associated with this plan are expected to be placed in service during 2010, with other segments placed in service through 2019, depending on siting, permitting and construction schedules.

The capital expenditure estimate for environmental projects includes emissions control equipment to meet anticipated air quality and visibility targets, including the reduction of sulfur dioxide, nitrogen oxide and particulate matter emissions. This estimate includes the installation of new or the replacement of existing emissions control equipment at a number of units at several of PacifiCorp's coal-fired generating facilities.

Capital expenditures related to operating projects consist of routine expenditures for distribution, transmission, generation, mining and other infrastructure needed to service existing and expected demand.

Obligations and Commitments

Contractual Obligations

PacifiCorp has contractual obligations that may affect its consolidated financial condition. The following table summarizes PacifiCorp's material contractual obligations as of December 31, 2009 (in millions):

	Payments Due By Periods				
	2010	2011-2012	2013-2014	2015 and After	Total
Long-term debt, including interest:					
Fixed-rate obligations	$ 369	$ 1,269	$ 1,037	$ 9,676	$ 12,351
Variable-rate obligations (1)	6	10	90	583	689
Capital leases, including interest	9	16	20	94	139
Operating leases	5	9	7	40	61
Asset retirement obligations	15	44	22	558	639
Power purchase agreements (2):					
Electricity commodity contracts	91	75	56	57	279
Electricity capacity contracts	158	188	143	399	888
Electricity mixed contracts	13	26	26	140	205
Transmission	117	212	164	775	1,268
Fuel purchase agreements (2):					
Natural gas supply and transportation	250	200	76	322	848
Coal supply and transportation	304	391	344	876	1,915
Other purchase obligations	784	243	41	142	1,210
Other long-term liabilities (3)	117	9	6	62	194
Total contractual cash obligations	$ 2,238	$ 2,692	$ 2,032	$ 13,724	$ 20,686

(1) Consists of principal and interest for tax-exempt bond obligations with interest rates scheduled to reset periodically prior to maturity. Future variable interest rates are set at December 31, 2009 rates. Refer to "Interest Rate Risk" in Item 7A of this Form 10-K for additional discussion related to variable-rate liabilities.

(2) Commodity contracts are agreements for the delivery of energy. Capacity contracts are agreements that provide rights to energy output, generally of a specified generating facility. Forecasted or other applicable estimated prices were used to determine total dollar value of the commitments for purposes of the table.

(3) Includes environmental and hydroelectric relicensing commitments recorded in the Consolidated Balance Sheets that are contractually or legally binding and contributions expected to be made to the PacifiCorp Retirement Plan during 2010 as disclosed in Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Excludes regulatory liabilities and employee benefit plan obligations that are not legally or contractually fixed as to timing and amount. Deferred income taxes are excluded since cash payments are based primarily on taxable income for each year. Uncertain tax positions are also excluded because the amounts and timing of cash payments are not certain.

Commercial Commitments

PacifiCorp's commercial commitments include surety bonds that provide indemnities for PacifiCorp in relation to various commitments it has to third parties for obligations in the event of default by PacifiCorp. In the event of default by PacifiCorp, the bonding agency would seek recovery from PacifiCorp in the amount of the bond. The majority of these bonds are continuous in nature and renew annually. Based on current contractual commitments, PacifiCorp's level of surety bonding after December 31, 2009 is estimated to be approximately $27 million per year. This estimate is based on current information and actual amounts may vary due to rate changes or changes to the general operations of PacifiCorp.

Regulatory Matters

PacifiCorp is subject to comprehensive regulation. In addition to the discussion contained herein regarding regulatory matters, refer to Item 1 of this Form 10-K for further discussion regarding PacifiCorp's general regulatory framework.

Certain regulatory matters are subject to uncertainties that require the use of estimates on the Consolidated Financial Statements, particularly that related to SB 408. Refer to Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion.

Utah

In July 2008, PacifiCorp filed a general rate case with the UPSC requesting an annual increase of $161 million prior to any consideration of the UPSC's order in the 2007 general rate case. In September 2008, PacifiCorp filed supplemental testimony that reflected then-current revenues and other adjustments based on the August 2008 order in the 2007 general rate case. The supplemental filing reduced PacifiCorp's request to $115 million. In October 2008, the UPSC issued an order changing the test period from the twelve months ending June 2009 using end-of-period rate base to the forecast calendar year 2009 using average rate base. In December 2008, PacifiCorp updated its filing to reflect the change in the test period. The updated filing proposed an increase of $116 million. In March 2009, a settlement agreement was filed with the UPSC resolving all remaining revenue requirement issues, resulting in parties agreeing, among other settlement terms, on an annual increase of $45 million, or an average price increase of 3%, effective May 8, 2009. In April 2009, the UPSC issued its final order approving the revenue requirement settlement agreement.

In March 2009, Utah's governor signed Senate Bill 75 that provides additional regulatory tools for the UPSC to use in the ratemaking process. The additional tools provided in the legislation allow for single item cost recovery of major capital investments outside of the general rate case process and allow for, but do not require, the use of an energy balancing account.

In March 2009, PacifiCorp filed for an ECAM with the UPSC. The filing recommends that the UPSC adopt the ECAM to recover the difference between base net power costs set in the next Utah general rate case and actual net power costs. The UPSC has separated the application into two phases to first address whether the mechanism is in the public interest, and then if it is found to be in the public interest, to determine the type of mechanism that should be implemented. Hearings on the public interest phase were completed in January 2010. In February 2010, the UPSC issued an order to proceed to the second phase to address design considerations in the development of an ECAM. Additionally, in February 2010, PacifiCorp filed an application with the UPSC seeking approval to defer the difference between the net power costs allowed by the UPSC's final order in PacifiCorp's 2009 general rate case and the actual net power costs incurred. If approved, the filing would establish a deferred cost balance to be considered for collection through any potential mechanism established in the second phase of the ECAM proceeding.

In February 2010, an application was filed with the UPSC by the Utah Association of Energy Users requesting an order requiring PacifiCorp to defer for later ratemaking treatment all revenues associated with sales of renewable energy credits in excess of the level included in Utah rates. If approved, Utah's share of any renewable energy credit sales above $18.5 million annually would be subject to consideration in a future proceeding.

In June 2009, PacifiCorp filed a general rate case with the UPSC for an increase of $67 million, or an average price increase of 5%. The forecasted test period is the twelve months ending June 30, 2010. In November 2009, as part of its rebuttal and surrebuttal filings, PacifiCorp reduced its rate increase request to $53 million. The UPSC issued its order February 18, 2010, approving a price increase of $32 million, or an average price increase of 2%.

In June 2009, PacifiCorp filed with the UPSC to increase its DSM cost recovery mechanism in Utah from an average of 2% of a customer's eligible monthly charges to 6%. In August 2009, a settlement agreement was filed with the UPSC requesting the DSM cost recovery mechanism be adjusted to 5%, representing an estimated annual increase of $35 million, which would enable PacifiCorp to continue to fund ongoing DSM programs and to recover previously incurred DSM expenditures. The UPSC approved the settlement agreement in August 2009, and the 5% DSM cost recovery mechanism became effective September 1, 2009.

In February 2010, PacifiCorp filed an alternative cost recovery application with the UPSC requesting recovery of $34 million associated with two major construction projects that are expected to be completed and in-service by June 2010. The mechanism provides for a ruling from the UPSC within 150 days of the application.

Oregon

In March 2009, PacifiCorp made the initial filing for the annual TAM with the OPUC for an annual increase of $21 million to recover the anticipated net power costs for the year beginning January 1, 2010. In August 2009, PacifiCorp filed a revision to its anticipated net power costs for the TAM, reflecting a slight decrease in the overall request to $20 million. In September 2009, PacifiCorp filed a settlement stipulation with the OPUC reducing the requested increase to $4 million, or an average price increase of less than 1%. In October 2009, the OPUC issued an order approving the settlement stipulation. In November 2009, PacifiCorp filed the final net power costs update for the TAM, based on the latest forward price curve. The final update shows a net power costs increase of $4 million, or an average price increase of less than 1%. The effective date for the TAM was January 1, 2010.

In April 2009, PacifiCorp filed a general rate case with the OPUC requesting an annual increase of $92 million. In August 2009, the requested annual increase was reduced to $83 million. In September 2009, PacifiCorp filed a settlement stipulation with the OPUC further reducing the proposed annual increase to $42 million, or an average price increase of 4%. The stipulation agreement also includes three tariff riders to collect an additional $8 million over a three-year period associated with various cost initiatives. In January 2010, the OPUC approved the stipulation effective February 2, 2010.

In February 2010, PacifiCorp made the initial filing for the annual TAM with the OPUC for an annual increase of $69 million to recover the anticipated net power costs forecasted for calendar year 2011. The rates in the TAM filing will be effective January 1, 2011 and are subject to updates throughout the proceeding.

For a discussion of SB 408, refer to Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Wyoming

In July 2008, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $34 million with an effective date of May 24, 2009. Power costs were excluded from the filing and were addressed separately in PacifiCorp's annual PCAM application filed in February 2009. In October 2008, the general rate case request was reduced by $5 million, to $29 million, to reflect a change in the in-service date of the High Plains wind-powered generating facility. In March 2009, a settlement agreement was filed with the WPSC revising the requested increase in Wyoming rates to $18 million annually beginning May 24, 2009, for an average overall price increase of 4%. Following public hearings in March 2009, the WPSC issued a final order approving the stipulation agreement in May 2009.

In February 2009, PacifiCorp filed its annual PCAM application with the WPSC. The PCAM application requested recovery of the difference between actual net power costs and the amount included in base rates, subject to certain limitations, for the period December 1, 2007 through November 30, 2008, and established for the first time an adjustment for the difference between forecasted net power costs and the amount included in base rates for the period December 1, 2008 through November 30, 2009. In the 2009 PCAM application, PacifiCorp requested a $2 million reduction to the current annual surcharge rate based on the results for the twelve-month period ended November 30, 2008, as well as a $16 million increase to the annual surcharge rate for the forecasted twelve-month period ending November 30, 2009, resulting in a net increase to the annual surcharge rate of $14 million on a combined basis. In March 2009, the WPSC approved PacifiCorp's motion to implement an interim rate increase of $7 million, effective April 1, 2009 consistent with the interim PCAM increase agreed to in the 2008 general rate case settlement agreement. In July 2009, a stipulation agreement was signed by the major participants in the case requesting that the April 2009 interim rate increase become the permanent rate for the entire amortization period through March 31, 2010, effectively reducing the net increase of $14 million sought in the application to $7 million, or an average price increase of 1%. In August 2009, the WPSC held a public hearing to consider the stipulation agreement, and after considering the evidence, the WPSC issued a bench decision approving the stipulation effective September 1, 2009.

In October 2009, PacifiCorp filed a general rate case with the WPSC requesting a rate increase of $71 million. Power costs are included in the general rate case, reflecting increased coal costs and the expiration of low cost long-term power purchase contracts. The application is based on a test period ending December 31, 2010. Two regulatory policy issues related to the tax treatment of equity AFUDC and the accounting for coal stripping costs are included in the case, which if approved by the WPSC, will reduce the requested rate increase by $9 million to an overall requested increase of $62 million, or an average price increase of 12%. The application requests a rate effective date of August 1, 2010. The WPSC has scheduled public hearings for April 2010.

In January 2010, PacifiCorp filed its annual PCAM application with the WPSC requesting recovery of $8 million in deferred net power costs.

Washington

In February 2008, PacifiCorp filed a general rate case with the WUTC for an annual increase of $35 million. In August 2008, PacifiCorp filed with the WUTC an all-party settlement agreement in which the parties agreed to an overall rate increase of $20 million, or 9%. The settlement was approved by the WUTC in October 2008 with the new rates effective October 15, 2008. The increase is composed of an $18 million increase to base rates, as well as a $2 million annual surcharge for approximately three years related to recovery of higher power costs incurred in 2005 due to poor hydroelectric conditions. PacifiCorp agreed to drop the current proposal for a generation cost adjustment mechanism and further committed not to propose such a mechanism in the next general rate case.

In February 2009, PacifiCorp filed a general rate case with the WUTC for an annual increase of $39 million. The filing included a request to begin collection of a deferral for costs associated with the 520-MW Chehalis natural gas-fired generating facility prior to its inclusion in rate base beginning in January 2010. The associated costs are estimated at $15 million. PacifiCorp has proposed to recover these costs through an extension of its hydroelectric deferral mechanism, thereby not affecting current customer rates. In August 2009, PacifiCorp filed an all-party settlement agreement proposing an annual increase of $14 million, or an average price increase of 5%. In December 2009, the WUTC approved the all-party settlement agreement. The new rates became effective January 1, 2010.

Idaho

In September 2008, PacifiCorp filed a general rate case with the IPUC for an annual increase of $6 million. In February 2009, a settlement signed by PacifiCorp, the IPUC staff and intervening parties was filed with the IPUC resolving all issues in the 2008 general rate case. The agreement stipulated a $4 million increase, or an average price increase of 3%, for non-contract retail customers in Idaho. As part of the stipulation, intervening parties acknowledged that PacifiCorp's acquisition of the 520-MW Chehalis natural gas-fired generating facility was prudent and the investment should be included in PacifiCorp's revenue requirement, and that PacifiCorp had demonstrated that its DSM programs are prudent. The parties also agreed on a base level of net power costs for any future ECAM calculations. In April 2009, the IPUC issued an order approving the stipulation effective April 18, 2009.

In June 2009, an agreement was reached with parties to the ECAM docket allowing for the implementation of an ECAM to recover the difference between the base level of net power costs recovered in rates and actual costs incurred, subject to the calculation methodology of the mechanism. In September 2009, the IPUC issued an order approving the ECAM stipulation as filed with an effective date of July 1, 2009. In February 2010, PacifiCorp filed an ECAM application with the IPUC requesting recovery of $2 million in deferred net power costs.

California

In February 2009, PacifiCorp filed a post-test-year adjustment mechanism ("PTAM") with the CPUC for major capital additions amounting to a rate increase of $1 million, or an average price increase of 2%. The filing included the addition of four major renewable resources: the 99-MW Seven Mile Hill, the 99-MW Glenrock, the 39-MW Glenrock III and the 99-MW Rolling Hills wind-powered generating facilities. The rates became effective March 19, 2009. In October 2009, PacifiCorp filed a PTAM with the CPUC for major capital additions amounting to a rate increase of $1 million, or an average price increase of 1%. The filing included the addition of two major renewable resources: the 99-MW High Plains and the 28-MW McFadden Ridge I wind-powered generating facilities. The rates became effective November 21, 2009.

In February 2009, PacifiCorp filed an application to extend its PTAM attrition adjustment (an adjustment for inflation) through 2010 and to delay filing its next general rate case by one year. The application was approved by the CPUC in April 2009. In October 2009, PacifiCorp filed its annual PTAM attrition adjustment with the CPUC. The filing requested an increase of $1 million, or an average price increase of 1%. The rates became effective January 1, 2010.

In July 2009, PacifiCorp made its annual filing under the ECAC requesting a rate reduction of $5 million, or an average price decrease of 5%, due to a decrease in net power costs. In December 2009, the CPUC approved the ECAC with an effective date of January 1, 2010.

In November 2009, PacifiCorp filed a general rate case with the CPUC requesting an annual increase of $8 million, or an average price increase of 10%. If approved by the CPUC, the rates will be effective January 1, 2011.

Environmental Laws and Regulation

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various other state and local agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and PacifiCorp is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. PacifiCorp believes it is in material compliance with all applicable laws and regulations. Refer to "Future Uses of Cash" for discussion of PacifiCorp's forecasted environmental-related capital expenditures.

Clean Air Standards

The Clean Air Act is a federal law, administered by the EPA, that provides a framework for protecting and improving the nation's air quality and controlling sources of air emissions. The implementation of new standards is generally outlined in State Implementation Plans ("SIPs"). SIPs, which are a collection of regulations, programs and policies to be followed are subject to public hearings, must be approved by the EPA and vary by state. Some states may adopt additional or more stringent requirements than those implemented by the EPA. The major Clean Air Act programs, which most directly affect PacifiCorp's operations, are described below.

National Ambient Air Quality Standards

Under the authority of the Clean Air Act, the EPA sets minimum national ambient air quality standards for six principal pollutants, consisting of carbon monoxide, lead, nitrogen oxide, particulate matter, ozone and SO_2, considered harmful to public health and the environment. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area that are determined to contribute to the nonattainment are required to reduce emissions. Most air quality standards require measurement over a defined period of time to determine the average concentration of the pollutant present.

On December 14, 2009, the EPA designated the Utah counties of Davis and Salt Lake, as well as portions of Box Elder, Cache, Tooele, Utah and Weber counties, to be in nonattainment of the fine particulate matter standard. This designation has the potential to impact PacifiCorp's Little Mountain, Lake Side and Gadsby facilities, depending on the requirements to be established in the Utah SIP. The impact on the PacifiCorp facilities is not anticipated to be significant.

In January 2010, the EPA proposed a rule to strengthen the national ambient air quality standard for ground level ozone. The proposed rule arises out of legal challenges claiming that the March 2008 rule that reduced the standard from 80 parts per billion to 75 parts per billion was not strict enough. The new rule proposes a standard between 60 and 70 parts per billion. The EPA expects to issue final standards later in 2010 with SIPs submitted in 2013.

In January 2010, the EPA finalized a one-hour air quality standard for nitrogen dioxide at 0.10 part per million. State attainment designations must be submitted to the EPA by January 1, 2011 and the EPA must finalize the designations by January 1, 2012.

In November 2009, the EPA proposed a new national ambient air quality standard for SO_2 to a level of between 50 and 100 parts per billion measured over one hour. The existing primary standards for SO_2 are 140 parts per billion measured over 24 hours and 30 parts per billion measured over an entire year. The EPA is under a consent decree to take final action on the proposed standards by June 2010.

If the stricter standards are implemented, the number of counties designated as nonattainment areas may increase. Businesses operating in newly designated nonattainment counties could face increased regulation and costs to monitor or reduce emissions. For instance, existing major emissions sources may have to install reasonably available control technologies to achieve certain reductions in emissions and undertake additional monitoring, recordkeeping and reporting. The construction or modification of facilities that are sources of emissions could become more difficult in nonattainment areas. Until the EPA issues the final rules and any legal challenges are settled, the impacts on PacifiCorp cannot be determined.

Clean Air Mercury Rule

The Clean Air Mercury Rule ("CAMR"), issued by the EPA in March 2005, was the United States' first attempt to regulate mercury emissions from coal-fired generating facilities through the use of a market-based cap-and-trade system. The CAMR, which mandated emissions reductions of approximately 70% by 2018, was overturned by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") in February 2008. The EPA plans to propose a new rule that will require coal-fired generating facilities to reduce mercury emissions by utilizing a mandated "Maximum Achievable Control Technology" rather than a cap-and-trade system. Under a consent decree, the EPA must issue a proposed rule to regulate mercury emission by March 2011 and a final rule no later than November 2011. If adopted, the new rule will likely result in incremental costs to install and maintain mercury emissions control equipment at each of PacifiCorp's coal-fired generating facilities and would increase the cost of providing service to customers. Until the EPA issues the proposed and final rules, the impacts on PacifiCorp cannot be determined.

Clean Air Interstate Rule

The EPA promulgated the CAIR in March 2005 to reduce emissions of nitrogen oxides NO_x and SO_2, precursors of ozone and particulate matter, from down-wind sources. The CAIR required states in the eastern United States to reduce emissions by implementing a plan based on a market-based cap-and-trade system, emission reductions, or both. The CAIR created separate trading programs for NO_x and SO_2 emission credits. The NO_x and SO_2 emissions reductions were planned to be accomplished in two phases, in 2009-2010 and 2015.

In July 2008, a three-judge panel of the D.C. Circuit issued a unanimous decision vacating the CAIR. In December 2008, the D.C. Circuit issued an opinion remanding, without vacating, the CAIR back to the EPA to conduct proceedings to fix the flaws in CAIR consistent with the D.C. Circuit's July 2008 ruling. The D.C. Circuit did not impose a schedule for completion on the EPA in its ruling, and the EPA informed the D.C. Circuit that development and finalization of a replacement rule could take approximately two years.

PacifiCorp's generating facilities are not subject to the CAIR. The impact of the replacement rule cannot be determined until the EPA issues its final rule. It is possible that the existing CAIR may be replaced with more stringent requirements to reduce SO_2 and NO_x emissions and that these requirements could be extended to the western United States through regulation or legislation such as the Clean Air Act Amendments of 2010, introduced in February 2010 by Senators Carper and Alexander. However, the provisions are not anticipated to have a material impact on PacifiCorp.

Regional Haze

The EPA has initiated a regional haze program intended to improve visibility in designated federally protected areas ("Class I areas"). Some of PacifiCorp's generating facilities meet the threshold applicability criteria under the Clean Air Visibility Rules. In accordance with the federal requirements, states were required to submit SIPs by December 2007 to demonstrate reasonable progress towards achieving natural visibility conditions in Class I areas by requiring emission controls, known as best available retrofit technology, on sources constructed between 1962 and 1977 with emissions that are anticipated to cause or contribute to impairment of visibility. Wyoming has not yet submitted its SIP. Wyoming issued best available retrofit technology permits to PacifiCorp on December 31, 2009, requiring PacifiCorp to implement emission control projects that are consistent with the planned emission reduction projects at PacifiCorp's Wyoming generating facilities. PacifiCorp has appealed certain provisions of the Naughton and Jim Bridger generating facilities' permits. Utah submitted its SIP and suggested that the emission reduction projects planned by PacifiCorp are sufficient to meet its initial emission reduction requirements. In January 2009, the EPA made a finding that 37 states, including Wyoming, had failed to file a SIP that met some or all of the basic regional haze program requirements. As a result, Wyoming has two years from January 2009 to file and obtain the EPA's approval of a SIP that meets all of the regional haze program requirements or the state will be subject to a federal implementation plan administered by the EPA. PacifiCorp believes that its planned emission reduction projects will satisfy the regional haze requirements in Utah and Wyoming. It is possible that additional controls may be required after the respective SIPs have been submitted and approved or that the timing of installation of planned controls could change.

New Source Review

Under existing New Source Review ("NSR") provisions of the Clean Air Act, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory agency prior to (a) beginning construction of a new major stationary source of a regulated pollutant or (b) making a physical or operational change to an existing stationary source of such pollutants that increases certain levels of emissions, unless the changes are exempt under the regulations (including routine maintenance, repair and replacement of equipment). In general, projects subject to NSR regulations require pre-construction review and permitting under the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act. Under the PSD program, a project that emits threshold levels of regulated pollutants must undergo an analysis to determine the best available control technology and evaluate the most effective emissions controls after consideration of a number of factors. Violations of NSR regulations, which may be alleged by the EPA, states, environmental groups and others, potentially subject a company to material fines and other sanctions and remedies, including installation of enhanced pollution controls and funding of supplemental environmental projects.

As part of an industry-wide investigation to assess compliance with the NSR and PSD provisions, the EPA has requested information and supporting documentation from numerous utilities regarding their capital projects for various generating facilities. A NSR enforcement case against an unrelated utility has been decided by the United States Supreme Court, holding that an increase in the annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. Between 2001 and 2003, PacifiCorp responded to requests for information relating to their capital projects at their generating facilities. PacifiCorp has been engaged in periodic discussions with the EPA over several years regarding PacifiCorp's historical projects and their compliance with NSR and PSD provisions. Final resolution has not been achieved. PacifiCorp cannot predict the outcome of its discussions with the EPA at this time; however, PacifiCorp could be required to install additional emissions controls and incur additional costs and penalties in the event it is determined that PacifiCorp's historic projects did not meet all regulatory requirements.

Numerous changes have been proposed to the NSR rules and regulations over the last several years. In addition to the proposed changes, differing interpretations by the EPA and the courts, and the recent change in administration, create risk and uncertainty for entities when seeking permits for new projects and installing emission controls at existing facilities under NSR requirements. PacifiCorp monitors these changes and interpretations to ensure permitting activities are conducted in accordance with the applicable requirements.

Climate Change

The increased global attention to climate change has resulted in significant measures being proposed at the federal level to regulate GHG emissions. The United States Congress and federal policy makers, with President Obama's support, are considering comprehensive climate change legislation such as the American Clean Energy and Security Act of 2009 ("Waxman-Markey bill"), which includes a market-based cap-and-trade program that is intended to reduce GHG emissions 83% below 2005 levels by 2050. In December 2009, the EPA published its findings that GHG threaten the public health and welfare and is pursuing regulation of GHG emissions under the Clean Air Act. In early 2010, legislation and resolutions were introduced in the United States Congress that would disapprove the findings submitted by the EPA and clarify that the United States Congress did not intend to regulate GHG emissions under the Clean Air Act. To date, two bills, one by Representative Early Pomeroy and one by Representatives Ike Skelton, Collin Peterson and Jo Ann Emerson, have been introduced in the United States House of Representatives seeking to amend the Clean Air Act to preclude the EPA from regulating GHG emissions under the Clean Air Act. In addition, a disapproval resolution has been introduced by Senator Lisa Murkowski and others in the United States Senate disapproving the EPA's GHG endangerment finding. Litigation has also been filed in the D.C. Circuit challenging the EPA's GHG endangerment finding, including an action by twelve members of the United States House of Representatives. An additional 15 lawsuits have been filed by states, various industry groups, and others, petitioning the court for review of the endangerment finding.

PacifiCorp supports the implementation of reasonable emissions caps, but opposes the trading mechanism as imposing additional costs that do not result in decreased emissions. PacifiCorp also believes that any law or regulation should provide a reasonable transition period to allow the phase in of low-carbon generating technologies that will achieve sustainable and cost-effective GHG emissions reduction benefits.

While the debate continues at the federal and international level over the direction of climate change policy, several states have developed or are developing state-specific laws or regional legislative initiatives to report or mitigate GHG emissions. In addition, governmental, non-governmental and environmental organizations have become more active in pursuing litigation under existing laws.

PacifiCorp voluntarily reports its GHG emissions to the California Climate Action Registry and The Climate Registry. In September 2009, the EPA issued its final rule regarding mandatory reporting of GHG ("GHG Reporting") beginning January 1, 2010. Under GHG Reporting, suppliers of fossil fuels, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG are required to submit annual reports to the EPA. PacifiCorp is subject to this requirement and will submit its first report by March 31, 2011.

PacifiCorp is committed to operating in an environmentally responsible manner. Examples of PacifiCorp's significant investments in programs and facilities that will mitigate its GHG emissions include:

- PacifiCorp is the second largest owner of wind-powered generation capacity in the United States among rate-regulated utilities. Over the last three years, PacifiCorp has added 787 MW of owned wind generation capacity at a total cost of $1.6 billion to its portfolio of generating assets. PacifiCorp currently owns 921 MW of wind-powered generation capacity, excluding its 111-MW Dunlap Ranch I wind-powered generating facility that is currently under construction. Additionally, PacifiCorp has purchase power agreements with 705 MW of wind-powered generation capacity. Other renewable resources owned or contracted total an incremental capacity of 105 MW.
- PacifiCorp owns 1,158 MW of hydroelectric generation capacity.
- PacifiCorp's Energy Gateway Transmission Expansion Program represents a plan to build approximately 2,000 miles of new high-voltage transmission lines at a cost exceeding $6 billion. The plan includes several transmission line segments that will: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse resource areas, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area and the Western United States.
- PacifiCorp has offered customers a comprehensive set of demand-side management programs for more than 20 years. The programs assist customers to manage the timing of their usage, as well as to reduce overall energy consumption, resulting in lower utility bills.

The impact of pending federal, regional, state and international accords, legislation, regulation, or judicial proceedings related to climate change cannot be quantified in any meaningful range at this time. New laws, regulations or rules limiting GHG emissions could have a material adverse impact on PacifiCorp, the United States and the global economy. Companies and industries with higher GHG emissions, such as utilities with significant coal-fired generating facilities, will be subject to more direct impacts and greater financial and regulatory risks. The impact is dependent on numerous factors, none of which can be meaningfully quantified at this time. These factors include, but are not limited to, the magnitude and timing of GHG emissions reduction requirements; the design of the requirements; the cost, availability and effectiveness of emission control technology; the price, distribution method and availability of offsets and allowances used for compliance; government-imposed compliance costs; and the existence and nature of incremental cost recovery mechanisms. Examples of how new laws and regulations may impact PacifiCorp include:

- Additional costs may be incurred to purchase required emission allowances under the proposed market-based cap-and-trade system in excess of allocations that are received at no cost. These purchases would be necessary until new technologies could be developed and deployed to reduce emissions or lower carbon generation is available;
- Acquiring and renewing construction and operating permits for new and existing facilities may be costly and difficult;
- Additional costs may be incurred to purchase and deploy new generating technologies;
- Costs may be incurred to retire existing coal facilities before the end of their otherwise useful lives or to convert them to burn fuels, such as natural gas or biomass, that result in lower emissions;
- Operating costs may be higher and unit outputs may be lower; and
- Higher interest and financing costs and reduced access to capital markets may result to the extent that financial markets view climate change and GHG emissions as a financial risk.

PacifiCorp expects it will be allowed to recover the prudently incurred costs to comply with climate change requirements.

The impact of events or conditions caused by climate change, whether from natural processes or human activities, could vary widely, from highly localized to worldwide, and the extent to which a utility's operations may be affected is uncertain. Climate change may cause physical and financial risk through, among other things, sea level rise, changes in precipitation and extreme weather events. Consumer demand for energy may increase or decrease, based on overall changes in weather and as customers promote lower energy consumption through the continued use of energy efficiency programs or other means. Availability of resources to generate electricity, such as water for hydroelectric production and cooling purposes, may also be impacted by climate change and could influence PacifiCorp's existing and future electricity generation portfolio. These issues may have a direct impact on the costs of electricity production and increase the price customers pay or their demand for electricity.

International Accords

The December 2009 Copenhagen Accord called on officials from developed nations to voluntarily commit to quantified economy-wide emissions targets for 2020 by January 31, 2010. In January 2010, the Obama administration formally declared its desire to be associated with the Copenhagen Accord, informing the United Nations Framework Convention on Climate Change of the goal of reducing United States GHG emissions approximately 17% from 2005 levels by 2020, contingent upon the enactment of United States energy and climate change legislation. The United States' goal is not binding or enforceable absent from further action by the United States Congress to enact climate change legislation.

Federal Legislation

In June 2009, the United States House of Representatives passed the Waxman-Markey bill. In addition to a federal renewable portfolio standard, which would require utilities to obtain a portion of their energy from certain qualifying renewable sources and energy efficiency measures, the bill requires a reduction in GHG emissions beginning in 2012, with emission reduction targets of 3% below 2005 levels by 2012; 17% below 2005 levels by 2020; 42% below 2005 levels by 2030; and 83% below 2005 levels by 2050 under a cap-and-trade program. In September 2009, a similar bill was introduced in the United States Senate by Senators Barbara Boxer and John Kerry, which would require a reduction in GHG emissions beginning in 2012 with emission reduction targets consistent with the Waxman-Markey bill, with the exception of the 2020 target, which requires 20% reductions below 2005 levels.

Greenhouse Gas Tailoring Rule

The EPA published a proposed GHG "tailoring rule" in October 2009 that would require sources of GHG emissions in excess of 25,000 tons of CO_2 equivalent to conduct a determination of best available control technology under the PSD provisions for new and modified sources. In addition, the proposal would require sources of CO_2 equivalent emissions of 25,000 tons or more to obtain a Title V operating permit or incorporate GHG emissions into existing sources' Title V permits when they are renewed. The EPA is currently working to finalize the rules with an anticipated effective date for stationary sources beginning in 2011. Until final rules are issued, PacifiCorp cannot determine the impact on its facilities. Several organizations have indicated that they intend to challenge the EPA's final GHG tailoring rule.

Regional and State Activities

Several states have developed state-specific laws or regional legislative initiatives to report or mitigate GHG emissions that are expected to impact PacifiCorp, including:

- The Western Climate Initiative, a comprehensive regional effort to reduce GHG emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector. The Western Climate Initiative includes the states of California, Montana, New Mexico, Oregon, Utah and Washington and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. The state and provincial partners have agreed to begin reporting GHG emissions in 2011 for emissions that occur in 2010. The first phase of the cap-and-trade program will begin on January 1, 2012.
- An executive order signed by California's governor in June 2005 would reduce GHG emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80% below 1990 levels by 2050. In addition, California has adopted legislation that imposes a GHG emission performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the GHG emission levels of a state-of-the-art combined-cycle natural gas-fired generating facility, as well as legislation that adopts an economy-wide cap on GHG emissions to 1990 levels by 2020. An effort is currently underway to gather a sufficient number of signatures to institute a California ballot initiative, referenced as the "California Jobs Initiative", which seeks to place before the voters a requirement to suspend GHG regulations promulgated under California's GHG emission reduction legislation (Assembly Bill 32) until California's unemployment rate is lowered to 5.5%.
- Over the past three years, the states of California, Washington and Oregon have adopted GHG emissions performance standards for base load electrical generating resources. Under the laws in all three states, the emissions performance standards provide that emissions must not exceed 1,100 lbs of CO_2 per MWh. These GHG emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of 5 or more years) unless any base load generation supplied under long-term financial commitments comply with the GHG emissions performance standards.
- The Washington and Oregon governors enacted legislation in May 2007 and August 2007, respectively, establishing goals for the reduction of GHG emissions in their respective states. Washington's goals seek to (a) reduce emissions to 1990 levels by 2020; (b) reduce emissions to 25% below 1990 levels by 2035; and (c) reduce emissions to 50% below 1990 levels by 2050, or 70% below Washington's forecasted emissions in 2050. Oregon's goals seek to (a) cease the growth of Oregon GHG emissions by 2010; (b) reduce GHG levels to 10% below 1990 levels by 2020; and (c) reduce GHG levels to at least 75% below 1990 levels by 2050. Each state's legislation also calls for state government to develop policy recommendations in the future to assist in the monitoring and achievement of these goals.

Greenhouse Gas Litigation

PacifiCorp closely monitors ongoing environmental litigation. Many of the pending cases described below relate to lawsuits against industry that attempt to link GHG emissions to public or private harm. PacifiCorp believes the cases are without merit, despite recent decisions where United States Court of Appeals reversed district court rulings dismissing the cases in 2009. The lower courts initially refrained from adjudicating the cases under the "political question" doctrine, because of their inherently political nature. Nevertheless, an adverse ruling in any of these cases would likely result in increased regulation of GHG emitters, including PacifiCorp's generating facilities, and financial uncertainty.

In September 2009, the United States Court of Appeals for the Second Circuit (the "Second Circuit") issued its opinion in the case of *Connecticut v. American Electric Power, et al*, which remanded to the lower court a nuisance action by eight states and the City of New York against five large utility emitters of CO_2. The United States District Court for the Southern District of New York (the "Southern District of New York") dismissed the case in 2005, holding that the claims that GHG emissions from the defendants' coal-fueled generating facilities were causing harmful climate change and should be enjoined as a public nuisance under federal common law presented a "political question" that the court lacked jurisdiction to decide. The Second Circuit rejected this conclusion and stated the Southern District of New York was not precluded from determining the case on its merits.

In October 2009, a three judge panel in the United States Court of Appeals for the Fifth Circuit (the "Fifth Circuit") issued its opinion in the case of *Ned Comer, et al. v. Murphy Oil USA, et al*., a putative class action lawsuit against insurance, oil, coal and chemical companies, based on claims that the defendants' GHG emissions contributed to global warming that in turn caused a rise in sea levels and added to the ferocity of Hurricane Katrina, which combined to damage the plaintiff's private property, as well as public property. In 2007, the United States District Court for the Southern District of Mississippi (the "Southern District of Mississippi") dismissed the case based on the lack of standing and further held that the claims were barred by the political question doctrine. The Fifth Circuit reversed the lower court decision and held that the plaintiffs had standing to assert their public and private nuisance, trespass and negligence claims, and concluded that the claims did not present a political question. The case was remanded to the Southern District of Mississippi for further proceedings with the court noting that it had not determined, and would leave to the lower court to analyze, whether the alleged chain of causation satisfies the proximate cause requirement under Mississippi state common law.

In October 2009, the United States District Court for the Northern District of California (the "Northern District of California") granted the defendants' motions to dismiss in the case of *Native Village of Kivalina v. ExxonMobil Corporation, et al*. The plaintiffs filed their complaint in February 2008, asserting claims against 24 defendants, including electric generating companies, oil companies and a coal company, for public nuisance under state and federal common law based on the defendants' GHG emissions. MEHC was a named defendant in the Kivalina case. The Northern District of California dismissed all of the plaintiffs' federal claims, holding that the court lacked subject matter jurisdiction to hear the claims under the political question doctrine, and that the plaintiffs lacked standing to bring their claims. The Northern District of California declined to hear the state law claims and the case was dismissed with prejudice to their future presentation in an appropriate state court.

Several lawsuits have also been filed against governmental agencies, most notably *Massachusetts v. EPA*. In April 2007, in Massachusetts v. EPA, the United States Supreme Court found that GHG are air pollutants and are covered by the Clean Air Act. The United States Supreme Court decision resulted from a petition for rulemaking filed by more than a dozen environmental, renewable energy and other organizations. The court held that the EPA must determine whether or not GHG emissions contribute to air pollution which may reasonably be anticipated to endanger public health or welfare, or whether the science is too uncertain to make a reasoned decision. In December 2009, the EPA determined that GHG emissions in the atmosphere threaten the public health and welfare of current and future generations and is pursuing regulation of GHG emissions under the Clean Air Act. Unless superseded by congressional action, the EPA ruling is likely to lead to stricter emission limits.

Renewable Portfolio Standards

The renewable portfolio standards ("RPS") described below could significantly impact PacifiCorp's consolidated financial results. Resources that meet the qualifying electricity requirements under the RPS vary from state to state. Each state's RPS requires some form of compliance reporting and PacifiCorp can be subject to penalties in the event of noncompliance.

In November 2006, Washington voters approved a ballot initiative establishing a RPS requirement for qualifying electric utilities, including PacifiCorp. The requirements are 3% of retail sales by January 1, 2012 through 2015, 9% of retail sales by January 1, 2016 through 2019 and 15% of retail sales by January 1, 2020. The WUTC has adopted final rules to implement the initiative.

In June 2007, the Oregon Renewable Energy Act ("OREA") was adopted, providing a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the OREA, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least 5% in 2011 through 2014, 15% in 2015 through 2019, 20% in 2020 through 2024, and 25% in 2025 and subsequent years. As required by the OREA, the OPUC has approved an automatic adjustment clause to allow an electric utility, including PacifiCorp, to recover prudently incurred costs of its investments in renewable energy generating facilities and associated transmission costs.

California law requires electric utilities to increase their procurement of renewable resources by at least 1% of their annual retail electricity sales per year so that 20% of their annual electricity sales are procured from renewable resources by no later than December 31, 2010. In May 2008, PacifiCorp and other small multi-jurisdictional utilities ("SMJU") received further guidance from the CPUC on the treatment of SMJUs in the California RPS program. In August 2008, concurrent with its annual RPS compliance filing, PacifiCorp, joined by another SMJU, filed a Joint Motion for Review of the decision, including banking of RPS procurement made while it awaited further guidance from the CPUC on the treatment of SMJUs during the 2004-2006 period. In May 2009, the CPUC denied the Joint Motion for Review.

In September 2009, California's governor issued Executive Order S-21-09 requiring the California Air Resources Board to adopt a regulation consistent with a 33% renewable electricity energy target established in Executive Order S-14-08 by July 31, 2010 that will encourage the creation and use of renewable energy sources and build on the existing RPS program.

In March 2008, Utah's governor signed Utah Senate Bill 202. Among other things, this law provides that, beginning in the year 2025, 20% of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and demand-side management programs. Qualifying renewable energy sources can be located anywhere in the WECC areas, and renewable energy credits can be used.

Water Quality Standards

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In July 2004, the EPA established significant new technology-based performance standards for existing electric generating facilities that take in more than 50 million gallons of water per day. These rules are aimed at minimizing the adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost as a result of water withdrawals. In response to a legal challenge to the rule, in January 2007, the United States Court of Appeals for the Second Circuit ("Second Circuit") remanded almost all aspects of the rule to the EPA, without addressing whether companies with cooling water intake structures were required to comply with these requirements. On appeal from the Second Circuit, in April 2009, the United States Supreme Court ruled that the EPA permissibly relied on a cost-benefit analysis in setting the national performance standards regarding "best technology available for minimizing adverse environmental impact" at cooling water intake structures and in providing for cost-benefit variances from those standards as part of the §316(b) Clean Water Act Phase II regulations. The United States Supreme Court remanded the case back to the Second Circuit to conduct further proceedings consistent with its opinion. Compliance and the potential costs of compliance, therefore, cannot be ascertained until such time as the Second Circuit takes action or further action is taken by the EPA. Currently, PacifiCorp's Dave Johnston Plant, which has water cooling towers, exceeds the 50 million gallons of water per day intake threshold. In the event that PacifiCorp's existing intake structures require modification or alternative technology required by new rules, expenditures to comply with these requirements could be significant. PacifiCorp believes that it currently has, or has initiated the process to receive, all required water quality permits.

Coal Combustion Byproduct Disposal

In December 2008, an ash impoundment dike at the Tennessee Valley Authority's Kingston power plant collapsed after heavy rain, releasing a significant amount of fly ash and bottom ash, coal combustion byproducts, and water to the surrounding area. In light of this incident, federal and state officials have called for greater regulation of coal combustion storage and disposal. The EPA is currently considering the regulation of coal combustion byproducts under the Resource Conservation and Recovery Act and a proposed rule addressing these materials is imminent. PacifiCorp operates 16 surface impoundments and 6 landfills that contain coal combustion byproducts. These ash impoundments and landfills may be impacted by additional regulation, particularly if the materials are regulated as hazardous waste under Subtitle C of the Resource Conservation Act, and could pose significant additional costs associated with ash management and disposal activities at PacifiCorp's coal-fired generating facilities. The impact of any new regulations on coal combustion byproducts cannot be determined at this time.

Other

Other laws, regulations and agencies to which PacifiCorp is subject include, but are not limited to:

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding environmental contingencies.
- The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of mining activities. Refer to Note 10 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding mine reclamation obligations.
- The FERC oversees the relicensing of existing hydroelectric systems and is also responsible for the oversight and issuance of licenses for new construction of hydroelectric systems, dam safety inspections and environmental monitoring. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the relicensing of certain of PacifiCorp's existing hydroelectric facilities.

Credit Ratings

PacifiCorp's senior secured and senior unsecured credit ratings are as follows:

	Fitch	Moody's	Standard & Poor's
Senior secured debt	A-	A2	A
Senior unsecured debt	BBB+	Baa1	A-
Outlook	Stable	Stable	Stable

Debt and preferred securities of PacifiCorp are rated by the credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of PacifiCorp's ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

PacifiCorp has no credit rating-downgrade triggers that would accelerate the maturity dates of outstanding debt and a change in ratings is not an event of default under the applicable debt instruments. PacifiCorp's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities. Certain authorizations or exemptions by regulatory commissions for the issuance of securities are valid as long as PacifiCorp maintains investment grade ratings on senior secured debt. A downgrade below that level would necessitate new regulatory applications and approvals.

In accordance with industry practice, certain agreements, including derivative contracts, contain provisions that require PacifiCorp to maintain specific credit ratings on its unsecured debt from one or more of the major credit rating agencies. These agreements, including derivative contracts, may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2009, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements, including derivative contracts, had been triggered as of December 31, 2009, PacifiCorp would have been required to post $310 million of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings or other factors. Refer to Note 7 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for a discussion of PacifiCorp's collateral requirements specific to PacifiCorp's derivative contracts.

Limitations

In addition to PacifiCorp's capital structure objectives, its debt capacity is also governed by its contractual and regulatory commitments.

PacifiCorp's revolving credit and other financing agreements contain customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0. Management believes that PacifiCorp could have borrowed an additional $6.0 billion as of December 31, 2009 without exceeding this threshold. Any additional borrowings would be subject to market conditions and amounts may be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements.

The state regulatory orders that authorized the acquisition by MEHC contain restrictions on PacifiCorp's ability to pay common dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

As of December 31, 2009, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to MEHC or PPW Holdings LLC (PacifiCorp's direct parent company and a direct subsidiary of MEHC) without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 47.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. This minimum level of common equity declines to 46.25% for the year ending December 31, 2010, 45.25% for the year ending December 31, 2011 and 44% thereafter. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by MEHC as common equity. As of December 31, 2009, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 51%, and PacifiCorp was permitted to dividend $928 million under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or MEHC if PacifiCorp's unsecured debt is rated BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of December 31, 2009, PacifiCorp's unsecured debt was rated A- by Standard & Poor's Rating Services, BBB+ by Fitch Ratings and Baa1 by Moody's Investor Service.

Inflation

Historically, overall inflation and changing prices in the economies where PacifiCorp operates have not had a significant impact on PacifiCorp's consolidated financial results. PacifiCorp operates under a cost-of-service based rate structure administered by various state commissions and the FERC. Under these rate structures, PacifiCorp is allowed to include prudent costs in its rates, including the impact of inflation. PacifiCorp attempts to minimize the potential impact of inflation on its operations by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

Off-Balance Sheet Arrangements

PacifiCorp from time to time enters into arrangements in the normal course of business to facilitate commercial transactions with third parties that involve guarantees or similar arrangements. PacifiCorp currently has indemnification obligations for breaches of warranties or covenants in connection with the sale of certain assets. In addition, PacifiCorp evaluates potential obligations that arise out of variable interests in unconsolidated entities, determined in accordance with authoritative accounting guidance. PacifiCorp believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these obligations is remote. Refer to Notes 10 and 17 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for more information on these obligations and arrangements.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting PacifiCorp, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty. Accordingly, the amounts currently reflected on the Consolidated Financial Statements will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by PacifiCorp's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with PacifiCorp's Summary of Significant Accounting Policies included in Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp is required to defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and assesses whether its regulatory assets and liabilities are probable of future inclusion in regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition, which could limit PacifiCorp's ability to recover its costs. Based upon this continuous assessment, PacifiCorp believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in regulated rates. The assessment reflects the current political and regulatory climate at both the state and federal levels and is subject to change in the future. If it becomes no longer probable that these costs or income will be included in regulated rates, the related regulatory assets and liabilities will be written off to operating income, refunded to customers or reflected as an adjustment to future regulated rates. Total regulatory assets were $1.539 billion and total regulatory liabilities were $838 million as of December 31, 2009. Refer to Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's regulatory assets and liabilities.

Derivatives

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. Exposures to commodity prices consist mainly of variations in the price of fuel to generate electricity and wholesale electricity that is purchased or sold. Electricity and natural gas prices are subject to wide price swings as supply and demand for these commodities are impacted by, among many other unpredictable items, changing weather, market liquidity, generating facility availability, customer usage, storage and transmission and transportation constraints. Interest rate risk exists on variable-rate debt, commercial paper and future debt issuances. PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. PacifiCorp may employ a number of different derivative contracts, including forwards, futures, options, swaps and other agreements, to manage price risk for electricity and other commodities and interest rate risk. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

Measurement Principles

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at fair value unless they are designated as normal purchases and normal sales and qualify for the exception afforded by accounting principles generally accepted in the United States of America. When available, the fair value of derivative contracts is determined using unadjusted quoted prices for identical contracts on the applicable exchange in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. PacifiCorp bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first six years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first six years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on significant unobservable inputs. The fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. The assumptions used in these models are critical, since any changes in assumptions could have a significant impact on the fair value of the contracts.

Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve. Option components are valued using Black-Scholes-type models, such as European option, Asian option, spread option and best-of option, with the appropriate forward price curve and other inputs.

Classification and Recognition Methodology

Almost all of PacifiCorp's derivative contracts are probable of inclusion in regulated rates or are accounted for as cash flow hedges. Therefore, changes in the fair value of derivative contracts are generally recorded as net regulatory assets or liabilities or accumulated other comprehensive income (loss) ("AOCI"). Accordingly, amounts are generally not recognized in earnings until the contracts are settled and the forecasted transaction has occurred. As of December 31, 2009, PacifiCorp had $367 million recorded as net regulatory assets and $- million recorded as AOCI, before tax, related to derivative contracts on the Consolidated Balance Sheets. If it becomes no longer probable that a derivative will be included in regulated rates, the regulatory asset or liability will be written off and recognized in earnings. For PacifiCorp's derivatives designated as hedging contracts, PacifiCorp discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, future changes in the value of the derivative are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the contract settles and the hedged item is recognized in earnings, unless it becomes probable that the hedged forecasted transaction will not occur, at which time associated deferred amounts in AOCI are immediately recognized in earnings.

Pension and Other Postretirement Benefits

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees. In addition, certain bargaining unit employees participate in joint trust plans to which PacifiCorp contributes. PacifiCorp recognizes the funded status of its defined benefit pension and other postretirement benefit plans on the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2009, PacifiCorp recognized a net liability totaling $569 million for the under-funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2009, amounts not yet recognized as a component of net periodic benefit cost and that were included in regulatory assets totaled $599 million and AOCI totaled $9 million.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, expected long-term rate of return on plan assets and healthcare cost trend rates. These actuarial assumptions are reviewed annually and modified as appropriate. PacifiCorp believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior experience and current market conditions. Refer to Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about PacifiCorp's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2009.

PacifiCorp chooses a discount rate based upon high quality fixed-income investment yields in effect as of the measurement date that corresponds to the expected benefit period. The pension and other postretirement benefit liabilities, as well as expenses, increase as the discount rate is reduced.

In establishing its assumption as to the expected long-term rate of return on plan assets, PacifiCorp reviews the expected asset allocation and develops return assumptions for each asset class based on historical performance and forward-looking views of the financial markets. Pension and other postretirement benefit expenses increase as the expected long-term rate of return on plan assets decreases. PacifiCorp regularly reviews its actual asset allocations and periodically rebalances its investments to its targeted allocations when considered appropriate.

PacifiCorp chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate gradually declines to 5% in 2016, at which point the rate is assumed to remain constant. Refer to Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for healthcare cost trend rate sensitivity disclosures.

The actuarial assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to the amount of pension and other postretirement benefit expense recorded and the funded status. If changes were to occur for the following assumptions, the approximate effect on the Consolidated Financial Statements would be as follows (in millions):

	Pension Plans		Other Postretirement Benefit Plan	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
Effect on December 31, 2009 Benefit Obligations:				
Discount rate	$ (63)	$ 69	$ (30)	$ 34
Effect on 2009 Periodic Cost:				
Discount rate	$ (4)	$ 4	$ -	$ -
Expected rate of return on plan assets	(5)	5	(2)	2

A variety of factors affect the funded status of the plans, including asset returns, discount rates, plan changes and the plan funding practices of PacifiCorp. Federal laws may require PacifiCorp to increase future contributions to its pension plans and there may be more volatility in annual contributions than historically experienced, which could have a material impact on consolidated financial results.

Income Taxes

In determining PacifiCorp's income taxes, management is required to interpret complex tax laws and regulations, which includes consideration of regulatory implications imposed by PacifiCorp's various regulatory jurisdictions. In preparing tax returns, PacifiCorp is subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Although the ultimate resolution of PacifiCorp's federal, state and local tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these tax positions. The aggregate amount of any additional tax liabilities that may result from these examinations, if any, is not expected to have a material adverse impact on PacifiCorp's consolidated financial results. Assets and liabilities are established for uncertain tax positions taken or positions expected to be taken in income tax returns when such positions are judged to not meet the "more-likely-than-not" threshold based on the technical merits of the position.

PacifiCorp is required to pass income tax benefits related to certain property-related basis differences and other various differences on to its customers in most state jurisdictions. These amounts were recognized as a net regulatory asset totaling $401 million as of December 31, 2009 and will be included in regulated rates when the temporary differences reverse. Management believes the existing net regulatory assets are probable of inclusion in regulated rates. If it becomes no longer probable that these costs will be included in regulated rates, the related regulatory asset will be written off to operating income.

Revenue Recognition – Unbilled Revenue

Unbilled revenue was $214 million as of December 31, 2009. Revenue is recognized as electricity is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts and composition of customer classes. Estimates are generally reversed in the following month and actual revenue is recorded based on subsequent meter readings. Historically, any differences between the actual and estimated amounts have been immaterial.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

PacifiCorp's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. PacifiCorp's significant market risks are primarily associated with commodity prices and interest rates. The following sections address the significant market risks associated with PacifiCorp's business activities. PacifiCorp has also established guidelines for credit risk management. Refer to Notes 2, 6 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's accounting for derivative contracts.

Risk Management

PacifiCorp has a risk management committee that is responsible for the oversight of market and credit risk relating to the commodity transactions of PacifiCorp. To limit PacifiCorp's exposure to market and credit risk, the risk management committee recommends, and executive management establishes, policies, limits and commodity strategies, which are reviewed frequently to respond to changing market conditions.

Risk is an inherent part of PacifiCorp's business and activities. PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in PacifiCorp's business. To assist in managing the volatility relating to these exposures, PacifiCorp enters into various transactions, including derivative transactions, consistent with PacifiCorp's risk management policy and procedures. The risk management policy governs energy transactions and is designed for hedging PacifiCorp's existing energy and asset exposures, and to a limited extent, the policy permits arbitrage and trading activities to take advantage of market inefficiencies. The policy also governs the types of transactions authorized for use and establishes guidelines for credit risk management and management information systems required to effectively monitor such derivative use. PacifiCorp's risk management policy provides for the use of only those contracts that have a similar volume or price relationship to its portfolio of assets, liabilities or anticipated transactions, thereby ensuring that such contracts will be primarily used for hedging. PacifiCorp does not engage in a material amount of proprietary trading activities.

Commodity Price Risk

PacifiCorp is principally exposed to electricity and natural gas commodity price risk as PacifiCorp has an obligation to serve retail customer load in its service territory. PacifiCorp's load and generation assets represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel to generate electricity and wholesale electricity that is purchased and sold. Electricity and natural gas prices are subject to wide price swings as supply and demand for these commodities are impacted by, among many other unpredictable items, changing weather, market liquidity, generating facility availability, customer usage and storage, transmission and transportation constraints. To mitigate a portion of its commodity price risk, PacifiCorp uses commodity contracts, which may be derivatives, including forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. The settled cost of these contracts is generally included in regulated rates. PacifiCorp's energy purchase and sales activities are governed by PacifiCorp's risk management policy and the risk levels established as part of that policy. Forward contracts are used to economically hedge both committed and forecasted energy purchases and sales. Accordingly, the net unrealized gains and losses on those forward contracts that are accounted for as derivatives, and that are probable of inclusion in regulated rates, are recorded as net regulatory assets or liabilities. Consolidated financial results may be negatively impacted if the costs of wholesale electricity and fuel are higher than what is permitted to be included in regulated rates.

PacifiCorp measures the market risk in its electricity and natural gas portfolio daily, utilizing a historical Value-at-Risk ("VaR") approach and other measurements of net position. PacifiCorp also monitors its portfolio exposure to market risk in comparison to established thresholds and measures its open positions subject to price risk in terms of quantity at each delivery location for each forward time period. VaR computations for the electricity and natural gas commodity portfolio are based on a historical simulation technique, utilizing historical price changes over a specified (holding) period to simulate potential forward energy market price curve movements to estimate the potential unfavorable impact of such price changes on the portfolio positions. The quantification of market risk using VaR provides a consistent measure of risk across PacifiCorp's continually changing portfolio. VaR represents an estimate of possible changes at a given level of confidence in fair value that would be measured on its portfolio assuming hypothetical movements in forward market prices and is not necessarily indicative of actual results that may occur.

PacifiCorp's VaR computations utilize several key assumptions. The calculation includes short-term commodity contracts, the expected resource and demand obligations from PacifiCorp's long-term contracts, the expected generation levels from PacifiCorp's generation assets and the expected retail and wholesale load levels. The portfolio reflects flexibility contained in contracts and assets, which accommodate the normal variability in PacifiCorp's demand obligations and generation availability. These contracts and assets are valued to reflect the variability PacifiCorp experiences as a load-serving entity. Contracts or assets that contain flexible elements are often referred to as having embedded options or option characteristics. These options provide for energy volume changes that are sensitive to market price changes. Therefore, changes in the option values affect the energy position of the portfolio with respect to market prices, and this effect is calculated daily. When measuring portfolio exposure through VaR, these position changes that result from the option sensitivity are held constant through the historical simulation. PacifiCorp's VaR methodology is based on a 48-month forward position, 95% confidence interval and one-day holding period.

As of December 31, 2009, PacifiCorp's estimated potential one-day unfavorable impact on fair value of the electricity and natural gas commodity portfolio over the next 48 months was $22 million, as measured by the VaR computations described above, compared to $12 million as of December 31, 2008. The minimum, average and maximum daily VaR (one-day holding periods) were as follows for the years ended December 31 (in millions):

	2009	2008	2007
Minimum VaR (measured)	$ 11	$ 9	$ 7
Average VaR (calculated)	18	14	12
Maximum VaR (measured)	23	23	20

PacifiCorp maintained compliance with its VaR limit procedures during the year ended December 31, 2009. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted limits.

Fair Value of Derivatives

The following table shows summarized information with respect to valuation techniques and contractual maturities of PacifiCorp's energy-related contracts qualifying as derivatives as of December 31, 2009 (in millions):

	Fair Value of Contracts at Period-End				
	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value
Non-trading [1]:					
Values based on quoted market prices from third-party sources	$ 68	$ (28)	$ (8)	$ -	$ 32
Values based on models and other valuation methods	(45)	(93)	(98)	(140)	(376)
Total non-trading	$ 23	$ (121)	$ (106)	$ (140)	$ (344)
Net regulatory asset (liability)	$ (30)	$ 151	$ 106	$ 140	$ 367

(1) Net derivative assets (liabilities) include a net cash collateral receivable of $25 million.

Standardized derivative contracts that are valued using market quotations are classified as "values based on quoted market prices from third-party sources." All remaining contracts, which include non-standard contracts and contracts for which market prices are not routinely quoted, are classified as "values based on models and other valuation methods." Both classifications utilize market curves as appropriate. PacifiCorp's valuation models are updated daily to reflect current market information, and evaluations and refinements of model assumptions are performed on a periodic basis.

The table that follows summarizes PacifiCorp's commodity risk on energy derivative contracts, excluding collateral netting of $25 million and $82 million, as of December 31, 2009 and 2008, respectively, and shows the effects of a hypothetical 10% increase and a 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value – Asset (Liability)	Hypothetical Price Change	Estimated Fair Value after Hypothetical Change in Price
As of December 31, 2009	$ (369)	10% increase	$ (362)
		10% decrease	(376)
As of December 31, 2008	$ (442)	10% increase	$ (415)
		10% decrease	(469)

Interest Rate Risk

The following table summarizes PacifiCorp's fixed-rate long-term debt and the estimated total fair values which would result from hypothetical increases or decreases in interest rates in effect as of December 31. Because of their fixed interest rates, these instruments do not expose PacifiCorp to the risk of earnings loss due to changes in market interest rates. In general, such increases and decreases in fair value would impact earnings and cash flows only if PacifiCorp were to reacquire all or a portion of these instruments prior to their maturity. It is assumed that the changes occur immediately and uniformly to each debt instrument. The hypothetical changes in market interest rates do not reflect what could be deemed best or worst case scenarios. For these reasons, actual results might differ from those reflected in the table (dollars in millions).

			Estimated Fair Value after Hypothetical Change in Interest Rates (bp = basis points)	
	Carrying Value	Fair Value	100 bp decrease	100 bp increase
As of December 31, 2009	$ 5,702	$ 6,188	$ 6,868	$ 5,614
As of December 31, 2008	$ 4,848	$ 5,114	$ 5,658	$ 4,648

As of December 31, 2009 and 2008, PacifiCorp had $655 million of variable-rate long-term tax exempt bond obligations. Currently, $113 million of these bonds have fixed term interest rates, with $45 million having interest rates scheduled to reset in 2010 and an additional $68 million scheduled to reset in 2013. As of December 31, 2009, PacifiCorp had no short-term debt outstanding. As of December 31, 2008, PacifiCorp had variable-rate short-term debt totaling $85 million. These variable-rate obligations expose PacifiCorp to the risk of increased interest expense in the event of increases in short-term interest rates. This market risk is not hedged; however, if the variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on PacifiCorp's consolidated annual interest expense in either year. The carrying amount of variable-rate long-term obligations approximates fair value.

Credit Risk

PacifiCorp extends unsecured credit to other utilities, energy marketers, financial institutions and other market participants in conjunction with wholesale energy supply and marketing activities. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on their contractual obligations to make or take delivery of electricity, natural gas or other commodities and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with the counterparty.

PacifiCorp analyzes the financial condition of each significant wholesale counterparty before entering into any transactions, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of wholesale counterparties, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtaining third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed interest fees for delayed payments. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2009, PacifiCorp's aggregate credit exposure from wholesale activities totaled $846 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2009, $660 million, or 78%, of PacifiCorp's credit exposure was with counterparties having investment grade credit ratings by either Moody's Investor Service or Standard & Poor's Rating Services. As of December 31, 2009, $4 million, or less than 1%, of such credit exposure was with counterparties having externally rated "non-investment grade" credit ratings, while an additional $182 million, or 22%, was with counterparties having financial characteristics deemed equivalent to "non-investment grade" by PacifiCorp based on internal review. As of December 31, 2009, two counterparties comprised $351 million, or 41%, of the aggregate credit exposure. One counterparty is rated investment grade by Moody's Investor Service and Standard & Poor's Rating Services and PacifiCorp is not aware of any factors that would likely result in a downgrade of the counterparty's credit ratings to below investment grade over the remaining term of transactions outstanding as of December 31, 2009. The other counterparty has a non-investment grade credit rating based on internal review as of December 31, 2009.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
PacifiCorp
Portland, Oregon

We have audited the accompanying consolidated balance sheets of PacifiCorp and subsidiaries (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of operations, cash flows, changes in equity and comprehensive income for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PacifiCorp and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

/s/Deloitte & Touche LLP

Portland, Oregon
March 1, 2010

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2009	**2008**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 117	$ 59
Accounts receivable, net	619	609
Income taxes receivable from affiliates	249	43
Inventories:		
Materials and supplies	192	184
Fuel	187	155
Derivative contracts	108	174
Deferred income taxes	39	74
Other current assets	61	78
Total current assets	1,572	1,376
Property, plant and equipment, net	15,537	13,824
Regulatory assets	1,539	1,624
Derivative contracts	43	86
Investments and other assets	275	257
Total assets	$ 18,966	$ 17,167

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2009	2008
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 553	$ 757
Accrued employee expenses	76	77
Accrued interest	111	89
Accrued taxes	67	73
Derivative contracts	85	130
Short-term debt	-	85
Current portion of long-term debt and capital lease obligations	16	144
Other current liabilities	105	111
Total current liabilities	1,013	1,466
Regulatory liabilities	838	821
Derivative contracts	410	490
Long-term debt and capital lease obligations	6,400	5,424
Deferred income taxes	2,625	2,025
Other long-term liabilities	948	874
Total liabilities	12,234	11,100
Commitments and contingencies (Note 13)		
Equity:		
PacifiCorp shareholders' equity:		
Preferred stock	41	41
Common equity:		
Common stock – 750 shares authorized, no par value, 357 shares issued and outstanding	-	-
Additional paid-in capital	4,379	4,254
Retained earnings	2,234	1,694
Accumulated other comprehensive loss, net	(6)	(2)
Total common equity	6,607	5,946
Total PacifiCorp shareholders' equity	6,648	5,987
Noncontrolling interest	84	80
Total equity	6,732	6,067
Total liabilities and equity	$ 18,966	$ 17,167

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2009	**2008**	**2007**
Operating revenue	$ 4,457	$ 4,498	$ 4,258
Operating costs and expenses:			
Energy costs	1,677	1,957	1,768
Operations and maintenance	1,035	985	998
Depreciation and amortization	549	490	497
Taxes, other than income taxes	136	112	101
Total operating costs and expenses	3,397	3,544	3,364
Operating income	1,060	954	894
Other income (expense):			
Interest expense	(394)	(343)	(314)
Allowance for borrowed funds	35	34	29
Allowance for equity funds	64	47	41
Interest income	19	11	15
Total other income (expense)	(276)	(251)	(229)
Income before income tax expense	784	703	665
Income tax expense	234	238	220
Net income	550	465	445
Net income attributable to noncontrolling interest	8	7	6
Net income attributable to PacifiCorp	$ 542	$ 458	$ 439

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2009	**2008**	**2007**
Cash flows from operating activities:			
Net income	$ 550	$ 465	$ 445
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	549	490	497
Provision for deferred income taxes	645	308	39
Changes in regulatory assets and liabilities	5	(37)	(45)
Other, net	(32)	(10)	3
Changes in other operating assets and liabilities, net of effects from acquisition:			
Accounts receivable and other assets	(5)	3	(81)
Derivative collateral, net	57	(82)	-
Inventories	(39)	(52)	(48)
Income taxes – affiliates, net	(206)	(20)	21
Accounts payable and other liabilities	(24)	(73)	(7)
Net cash flows from operating activities	1,500	992	824
Cash flows from investing activities:			
Capital expenditures	(2,328)	(1,789)	(1,519)
Acquisition, net of cash acquired	-	(308)	-
Purchases of available-for-sale securities	(21)	(52)	(25)
Proceeds from sales of available-for-sale securities	36	67	30
Other, net	5	6	17
Net cash flows from investing activities	(2,308)	(2,076)	(1,497)
Cash flows from financing activities:			
Net (repayments of) proceeds from short-term debt	(85)	85	(397)
Proceeds from long-term debt	992	797	1,193
Proceeds from previously reacquired long-term debt	-	216	-
Proceeds from equity contributions	125	450	200
Preferred stock dividends paid	(2)	(2)	(2)
Reacquired long-term debt	-	(216)	-
Repayments and redemptions of long-term debt and capital lease obligations	(144)	(413)	(127)
Redemptions of preferred stock subject to mandatory redemption	-	-	(38)
Other, net	(20)	(2)	13
Net cash flows from financing activities	866	915	842
Net change in cash and cash equivalents	58	(169)	169
Cash and cash equivalents at beginning of period	59	228	59
Cash and cash equivalents at end of period	$ 117	$ 59	$ 228

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	PacifiCorp Shareholders' Equity						
	Preferred Stock	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Noncontrolling Interest	Total Equity
Balance, January 1, 2007	$ 41	$ -	$ 3,600	$ 789	$ (4)	$ 66	$ 4,492
Net income	-	-	-	439	-	6	445
Contributions	-	-	200	-	-	46	246
Distributions	-	-	-	-	-	(39)	(39)
Preferred stock dividends declared	-	-	-	(2)	-	-	(2)
Other equity transactions	-	-	4	13	-	-	17
Balance, December 31, 2007	41	-	3,804	1,239	(4)	79	5,159
Net income	-	-	-	458	-	7	465
Other comprehensive income	-	-	-	-	2	-	2
Contributions	-	-	450	-	-	45	495
Distributions	-	-	-	-	-	(42)	(42)
Preferred stock dividends declared	-	-	-	(2)	-	-	(2)
Other equity transactions	-	-	-	(1)	-	(9)	(10)
Balance, December 31, 2008	41	-	4,254	1,694	(2)	80	6,067
Net income	-	-	-	542	-	8	550
Other comprehensive income	-	-	-	-	(4)	-	(4)
Contributions	-	-	125	-	-	28	153
Distributions	-	-	-	-	-	(38)	(38)
Preferred stock dividends declared	-	-	-	(2)	-	-	(2)
Other equity transactions	-	-	-	-	-	6	6
Balance, December 31, 2009	$ 41	$ -	$ 4,379	$ 2,234	$ (6)	$ 84	$ 6,732

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2009	2008	2007
Net income	$ 550	$ 465	$ 445
Other comprehensive income (loss), net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $(1), $- and $2	(4)	2	2
Fair value adjustment on cash flow hedges, net of tax of $-, $- and $(1)	-	-	(2)
Total other comprehensive income (loss), net of tax	(4)	2	-
Comprehensive income	546	467	445
Comprehensive income attributable to noncontrolling interest	8	7	6
Comprehensive income attributable to PacifiCorp	$ 538	$ 460	$ 439

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric company serving 1.7 million retail customers, including residential, commercial, industrial and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with public and private utilities, energy marketing companies and incorporated municipalities. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining facilities and services and environmental remediation services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of PacifiCorp and its subsidiaries in which it holds a controlling financial interest as of the financial statement date, including Bridger Coal Company in which PacifiCorp has a two-thirds interest. The Consolidated Statements of Operations include the revenues and expenses of an acquired entity from the date of acquisition. Intercompany accounts and transactions have been eliminated.

Certain amounts in the prior year Consolidated Financial Statements have been reclassified to conform to the current year presentation. Such reclassifications did not impact previously reported operating income, net income attributable to PacifiCorp or retained earnings.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; effects of regulation; long-lived asset recovery; accounting for contingencies, including environmental, regulatory and income tax matters; asset retirement obligations ("AROs"); and certain assumptions made in accounting for pension and other postretirement benefits. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp is required to defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and assesses whether its regulatory assets and liabilities are probable of future inclusion in regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition which could limit PacifiCorp's ability to recover its costs. Based upon this continuous assessment, PacifiCorp believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in regulated rates. The assessment reflects the current political and regulatory climate at both the state and federal levels and is subject to change in the future. If it becomes no longer probable that these costs or income will be included in regulated rates, the related regulatory assets and liabilities will be written off to operating income, refunded to customers or reflected as an adjustment to future regulated rates.

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Market participants are assumed to be independent, knowledgeable, and able and willing to transact. Nonperformance or credit risk is considered when determining the fair value of assets and liabilities. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value.

Cash Equivalents, Restricted Cash and Investments

Cash equivalents consist of funds invested in commercial paper, money market accounts and in other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted amounts are included in other current assets and investments and other assets on the Consolidated Balance Sheets.

Investments

PacifiCorp's management determines the appropriate classifications of investments in debt and equity securities at the acquisition date and reevaluates the classifications at each balance sheet date. PacifiCorp's investments in debt and equity securities are classified as available-for-sale.

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in accumulated other comprehensive income (loss) ("AOCI"), net of tax. Realized and unrealized gains and losses on the trust fund related to the final reclamation of leased coal mining property are recorded as net regulatory assets or liabilities since PacifiCorp expects costs associated with these activities to be included in regulated rates.

If in management's judgment a decline in the fair value of an investment below cost is other than temporary, the cost of the investment is written down to fair value. Factors considered in judging whether an impairment is other than temporary include: the financial condition, business prospects and creditworthiness of the issuer; the length of time that fair value has been less than cost; the relative amount of the decline; and whether or not PacifiCorp anticipates the fair value of the investment to recover prior to the expected time of sale. Impairment losses on equity securities are charged to earnings. With respect to an investment in a debt security, any resulting impairment loss is recognized in earnings if PacifiCorp intends to sell or expects to be required to sell the debt security before amortized cost is recovered. If PacifiCorp does not expect to ultimately recover the amortized cost basis, even if it does not intend to sell the security, the credit loss component is recognized in earnings and any difference between fair value and the amortized cost basis, net of the credit loss, is reflected in other comprehensive income (loss). A regulatory asset or liability is established for those investment losses or gains that are probable of inclusion in regulated rates.

Allowance for Doubtful Accounts

The allowance for doubtful accounts is based on PacifiCorp's assessment of the collectibility of payments from its customers. This assessment requires judgment regarding the ability of customers to pay the amounts owed to PacifiCorp or the outcome of any pending disputes. The change in the balance of the allowance for doubtful accounts, which is included in accounts receivable, net on the Consolidated Balance Sheets is summarized as follows for the years ended December 31 (in millions):

	2009	2008	2007
Beginning balance	$ 9	$ 7	$ 12
Charged to operating costs and expenses, net	12	14	9
Write-offs, net	(14)	(12)	(14)
Ending balance	$ 7	$ 9	$ 7

Derivatives

PacifiCorp employs a number of different derivative contracts, including forwards, futures, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities and interest rate risk. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at fair value unless they are designated as normal purchases and normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect reductions permitted under master netting arrangements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases and normal sales. Normal purchases and normal sales are not marked-to-market and operating revenue or energy costs are recognized on the Consolidated Statements of Operations when the contracts settle.

For PacifiCorp's derivatives designated as hedging contracts, PacifiCorp formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. PacifiCorp formally documents hedging activity by transaction type and risk management strategy.

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective, are included on the Consolidated Statements of Changes in Equity as AOCI, net of tax, until the contract settles and the hedged item is recognized in earnings. PacifiCorp discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, future changes in the value of the derivative are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the contract settles and the hedged item is recognized in earnings, unless it becomes probable that the hedged forecasted transaction will not occur, at which time associated deferred amounts in AOCI are immediately recognized in earnings.

For PacifiCorp's derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as net regulatory assets and liabilities. For contracts not probable of inclusion in regulated rates, changes in fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies, coal stocks, natural gas and fuel oil, which are stated at the lower of average cost or market.

Property, Plant and Equipment, Net

General

Property, plant and equipment is recorded at historical cost. PacifiCorp capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs, which includes debt and equity allowance for funds used during construction ("AFUDC"). The cost of major additions and betterments are capitalized, while costs for replacements, maintenance and repairs that do not improve or extend the lives of the related assets are charged to operating expense as incurred.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by PacifiCorp's various regulatory authorities. Periodic depreciation studies are completed to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the various regulatory authorities. Net salvage includes the estimated future residual values of the assets and any estimated removal costs, including AROs and other costs of removal. Estimated removal costs that are recovered through approved depreciation rates, but that do not meet the requirements of a legal ARO, are reflected in the cost of removal regulatory liability on the Consolidated Balance Sheets, and as such costs are incurred, the regulatory liability is reduced.

Generally when PacifiCorp retires or sells a component of regulated property, plant and equipment, it charges the original cost and any net proceeds from the disposition to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

PacifiCorp records debt and equity AFUDC, which represents the estimated costs of debt and equity funds necessary to finance additions to property, plant and equipment. AFUDC is capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related asset, as well as recover these costs through depreciation expense over the useful life of the related assets.

Asset Retirement Obligations

PacifiCorp recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. PacifiCorp's AROs are primarily related to final reclamation of leased coal mining property. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to property, plant and equipment) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Revenue Recognition

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes unbilled, as well as billed, amounts. As of December 31, 2009 and 2008, unbilled revenue was $214 million and $211 million, respectively, and is included in accounts receivable, net on the Consolidated Balance Sheets. Rates charged are established by regulators or contractual agreements.

The determination of sales to individual customers is based on the reading of the customer's meter, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. The estimate is reversed in the following month and actual revenue is recorded based on subsequent meter readings.

The monthly unbilled revenues of PacifiCorp are determined by the estimation of unbilled energy provided during the period, the assignment of unbilled energy provided to customer classes and the average rate per customer class. Factors that can impact the estimate of unbilled energy provided include, but are not limited to, seasonal weather patterns, customer usage patterns, historical trends, volumes, line losses, retail rate changes and composition of customer classes.

PacifiCorp records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Income Taxes

Berkshire Hathaway includes PacifiCorp in its United States federal income tax return. Consistent with established regulatory practice, PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

Deferred tax assets and liabilities are based on differences between the financial statement and tax basis of assets and liabilities using estimated tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of other comprehensive income are charged or credited directly to other comprehensive income. Changes in deferred income tax assets and liabilities that are associated with income tax benefits related to certain property-related basis differences and other various differences that PacifiCorp is required to pass on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability. These amounts were recognized as a net regulatory asset totaling $401 million and $409 million as of December 31, 2009 and 2008, respectively, and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense.

Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions. Investment tax credits included in other long-term liabilities on the Consolidated Balance Sheets were $46 million and $50 million as of December 31, 2009 and 2008, respectively.

In determining PacifiCorp's income taxes, management is required to interpret complex tax laws and regulations, which includes consideration of regulatory implications imposed by PacifiCorp's various regulatory jurisdictions. In preparing tax returns, PacifiCorp is subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Although the ultimate resolution of PacifiCorp's federal, state and local tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these tax positions. The aggregate amount of any additional tax liabilities that may result from these examinations, if any, is not expected to have a material adverse effect on PacifiCorp's consolidated financial results. Assets and liabilities are established for uncertain tax positions taken or positions expected to be taken in income tax returns when such positions are judged to not meet the "more-likely-than-not" threshold based on the technical merits of the position. PacifiCorp's unrecognized tax benefits are primarily included in accrued taxes and other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations.

Segment Information

PacifiCorp currently has one segment, which includes its regulated electric utility operations.

New Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2010-06 ("ASU No. 2010-06"), which amends FASB Accounting Standards Codification ("ASC") Topic 820, "Fair Value Measurements and Disclosures" ("ASC Topic 820"). ASU No. 2010-06 requires disclosure of (a) the amount of significant transfers into and out of Levels 1 and 2 of the fair value hierarchy and the reasons for those transfers and (b) gross presentation of purchases, sales, issuances and settlements in the Level 3 fair value measurement rollforward. This guidance clarifies that existing fair value measurement disclosures should be presented for each class of assets and liabilities. The existing disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements have also been clarified to ensure such disclosures are presented for the Levels 2 and 3 fair value measurements. This guidance is effective for interim and annual reporting periods beginning after December 15, 2009, with the exception of the disclosure requirement to present purchases, sales, issuances and settlements gross in the Level 3 fair value measurement rollforward, which is effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. PacifiCorp is currently evaluating the impact of adopting this guidance on its disclosures included within Notes to Consolidated Financial Statements.

In August 2009, the FASB issued ASU No. 2009-05, which amends ASC Topic 820. ASU No. 2009-05 clarifies how to measure the fair value of a liability for which a quoted price in an active market for the identical liability is not available. This guidance also clarifies that both a quoted price in an active market for the identical liability at the measurement date and the quoted price for the identical liability when traded as an asset in an active market when no adjustments to the quoted price of the asset are required represent Level 1 fair value measurements. PacifiCorp adopted this guidance as of October 1, 2009 and the adoption did not have a material impact on PacifiCorp's consolidated financial results and disclosures included within Notes to Consolidated Financial Statements.

In June 2009, the FASB issued authoritative guidance (included in ASC Topic 810, "Consolidation") that requires a primarily qualitative analysis to determine if an enterprise is the primary beneficiary of a variable interest entity. This analysis is based on whether the enterprise has (a) the power to direct the activities of the variable interest entity that most significantly impact the entity's economic performance and (b) the obligation to absorb losses of the entity or the right to receive benefits from the entity that could potentially be significant to the variable interest entity. In addition, enterprises are required to more frequently reassess whether an entity is a variable interest entity and whether the enterprise is the primary beneficiary of the variable interest entity. Finally, the guidance for consolidation or deconsolidation of a variable interest entity is amended and disclosure requirements about an enterprise's involvement with a variable interest entity are enhanced. This guidance is effective as of the beginning of the first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period and for interim and annual reporting periods thereafter, with early application prohibited. PacifiCorp has determined that its coal mining joint venture, Bridger Coal Company, will be deconsolidated on a prospective basis and accounted for under the equity method of accounting effective January 1, 2010, as the power to direct the activities that most significantly impact Bridger Coal Company's economic performance are shared with the joint venture partner. The deconsolidation of Bridger Coal Company will result in a decrease in assets, liabilities and noncontrolling interest equity of $192 million, $108 million and $84 million, respectively.

In April 2009, the FASB issued authoritative guidance (included in ASC Topic 320, "Investments – Debt and Equity Securities") that amends current other-than-temporary impairment guidance for debt securities to require a new other-than-temporary impairment model that shifts the focus from an entity's intent to hold the debt security until recovery to its intent, or expected requirement, to sell the debt security. In addition, this guidance expands the already required annual disclosures about other-than-temporary impairment for debt and equity securities, requires companies to include these expanded disclosures in interim financial statements and addresses whether an other-than-temporary impairment should be recognized in earnings, other comprehensive income or some combination thereof. PacifiCorp adopted this guidance as of April 1, 2009 and the adoption did not have a material impact on PacifiCorp's consolidated financial results and disclosures included within Notes to Consolidated Financial Statements.

In April 2009, the FASB issued authoritative guidance (included in ASC Topic 820) that clarifies the determination of fair value when a market is not active and if a transaction is not orderly. In addition, this guidance amends previous GAAP to require disclosures in interim and annual periods of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, during the period and defines "major categories" consistent with those described in previously existing GAAP. PacifiCorp adopted this guidance as of April 1, 2009 and the adoption did not have a material impact on PacifiCorp's consolidated financial results and disclosures included within Notes to Consolidated Financial Statements.

In December 2008, the FASB issued authoritative guidance (included in ASC Topic 715, "Compensation – Retirement Benefits") that requires enhanced disclosures about plan assets of defined benefit pension and other postretirement benefit plans to enable investors to better understand how investment allocation decisions are made and the major categories of plan assets. In addition, this guidance requires disclosure of the inputs and valuation techniques used to measure fair value and the effect of fair value measurements using significant unobservable inputs on changes in plan assets and establishes disclosure requirements for significant concentrations of risk within plan assets. PacifiCorp adopted this guidance as of December 31, 2009 and included the required disclosures within Notes to Consolidated Financial Statements. Refer to Note 11 for additional discussion.

In March 2008, the FASB issued authoritative guidance (included in ASC Topic 815, "Derivatives and Hedging") that requires enhanced disclosures about derivative contracts and hedging activities to enable investors to better understand how and why an entity uses derivative contracts and their effects on an entity's financial results. PacifiCorp adopted this guidance as of March 31, 2009 and included the required disclosures within Notes to Consolidated Financial Statements. Refer to Note 7 for additional discussion.

In December 2007, the FASB issued authoritative guidance (included in ASC Topic 810, "Consolidation") that establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. PacifiCorp adopted this guidance as of January 1, 2009. As a result, PacifiCorp has presented noncontrolling interest as a separate component of equity on the Consolidated Balance Sheets. Previously, these amounts were included in other long-term liabilities on the Consolidated Balance Sheets. Also, PacifiCorp has presented net income attributable to noncontrolling interest separately on the Consolidated Statements of Operations. Previously, these amounts were reported as operating expenses on the Consolidated Statements of Operations. This guidance has been applied retrospectively to all periods presented in the Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciation Life	2009	2008
Property, plant and equipment:			
Generation	15 – 80 years	$ 9,022	$ 8,155
Transmission	25 – 75 years	3,346	3,057
Distribution	44 – 52 years	5,332	5,109
Intangible plant [(1)]	5 – 50 years	752	721
Other	5 – 29 years	1,878	1,837
Property, plant and equipment in service		20,330	18,879
Accumulated depreciation and amortization		(6,623)	(6,275)
Net property, plant and equipment in service		13,707	12,604
Construction work-in-progress		1,830	1,220
Total property, plant and equipment, net		$ 15,537	$ 13,824

(1) Computer software costs included in intangible plant are initially assigned a depreciable life of 5 to 10 years.

Utility Plant Acquisition

On September 15, 2008, after having received the required regulatory approvals, PacifiCorp acquired from TNA Merchant Projects, Inc., an affiliate of Suez Energy North America, Inc., 100% of the equity interests of Chehalis Power Generating, LLC, an entity owning a 520-megawatt ("MW") natural gas-fired generating facility located in Chehalis, Washington. The total cash purchase price was $308 million and the estimated fair value of the acquired entity was primarily allocated to the facility. Chehalis Power Generating, LLC was merged into PacifiCorp immediately following the acquisition. The results of the facility's operations have been included in PacifiCorp's Consolidated Financial Statements since the acquisition date.

Unallocated Acquisition Adjustments

PacifiCorp has unallocated acquisition adjustments that represent the excess of costs of the acquired interests in property, plant and equipment purchased from the entity that first devoted the assets to utility service over their net book value in those assets. These unallocated acquisition adjustments included in other property, plant and equipment had an original cost of $157 million as of December 31, 2009 and 2008, and accumulated depreciation of $96 million and $91 million as of December 31, 2009 and 2008, respectively.

Depreciation Study

In August 2007, PacifiCorp filed applications with the regulatory commissions in Utah, Oregon, Wyoming, Washington and Idaho to change its rates of depreciation prospectively based on a new depreciation study. PacifiCorp received approval to change the depreciation rates effective January 1, 2008. The Oregon Public Utility Commission ("OPUC") order required additional modifications related to the depreciation lives of coal-fired generating facilities, which were approved in August 2008. The revised depreciation rates generally reflect an extension of the lives of PacifiCorp's assets. The most significant change resulted in an increase in the range of depreciable lives for steam plant from 20 – 43 years to 20 - 57 years. The revised depreciation rates resulted in a benefit to income before income tax expense during the year ended December 31, 2008 of approximately $47 million.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation and transmission facilities. PacifiCorp accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each generating facility or transmission line. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include PacifiCorp's share of the expenses of these facilities.

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility as of December 31, 2009 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 – 4 [1]	67%	$ 1,031	$ 489	$ 42
Wyodak [1]	80	339	178	20
Hunter No. 1	94	306	155	35
Colstrip Nos. 3 and 4 [1]	10	248	125	1
Hunter No. 2	60	194	93	24
Hermiston [2]	50	174	45	-
Craig Nos. 1 and 2	19	168	83	2
Hayden No. 1	25	46	23	2
Foote Creek	79	37	16	-
Hayden No. 2	13	28	15	1
Other transmission and distribution facilities	Various	84	21	29
Total		$ 2,655	$ 1,243	$ 156

(1) Includes transmission lines and substations.

(2) PacifiCorp has contracted to purchase the remaining 50% of the output of the Hermiston generating facility.

(5) Regulatory Matters

Regulatory Assets and Liabilities

Regulatory assets represent costs that are expected to be recovered in future regulated rates. PacifiCorp's regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2009	2008
Employee benefit plans [1]	9 years	$ 576	$ 564
Net unrealized loss on derivative contracts [2]	7 years	367	442
Deferred income taxes [3]	33 years	422	440
Other	Various	174	178
Total		$ 1,539	$ 1,624

(1) Substantially represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in regulated rates when recognized. Amounts are partially offset by $19 million and $26 million of the unamortized portion of net regulatory deferrals related to curtailment gains and the measurement date change transitional adjustment as of December 31, 2009 and 2008, respectively.

(2) Amounts represent net unrealized losses related to derivative contracts for which the settled amounts are expected to be included in regulated rates.

(3) Represents deferred income tax assets and liabilities that are associated with income tax benefits related to certain property-related basis differences and other various differences that PacifiCorp is required to pass on to its customers in most state jurisdictions.

PacifiCorp had regulatory assets not earning a return on investment of $1.385 billion and $1.460 billion as of December 31, 2009 and 2008, respectively.

Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. PacifiCorp's regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2009	2008
Cost of removal [1]	33 years	$ 755	$ 732
Deferred income taxes	Various	21	31
Other	Various	62	58
Total		$ 838	$ 821

(1) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing electric utility assets in accordance with accepted regulatory practices.

Rate Matters

Oregon Senate Bill 408 ("SB 408")

SB 408 requires PacifiCorp and other large regulated, investor-owned utilities that provide electric or natural gas service to Oregon customers to file an annual report each October with the OPUC comparing income taxes collected and income taxes paid, as defined by the statute and its administrative rules. If after its review, the OPUC determines the amount of income taxes collected differs from the amount of income taxes paid by more than $100,000, the OPUC must require the public utility to establish an automatic adjustment clause to account for the difference.

In April 2008, the OPUC approved the recovery of $35 million, plus interest, related to the 2006 tax year. The OPUC's April 2008 order on PacifiCorp's 2006 tax report is being challenged by the Industrial Customers of Northwest Utilities, which filed a petition in May 2008 with the Oregon Court of Appeals seeking judicial review of the April 2008 order. PacifiCorp believes the outcome of these proceedings will not have a material impact on its consolidated financial results.

In October 2009, PacifiCorp filed its 2008 tax report under SB 408. PacifiCorp's filing for the 2008 tax year indicated that PacifiCorp paid $38 million more in income taxes than was collected in rates from its retail customers. In January 2010, PacifiCorp entered into a stipulation with OPUC staff and the Citizens' Utility Board of Oregon, which if approved by the OPUC, would authorize a lower recovery totaling $2 million, including interest. The OPUC has until April 2010 to issue an order. No amounts have been recorded in relation to the 2008 tax report.

(6) Fair Value Measurements

The carrying amounts of PacifiCorp's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximate fair value because of the short-term maturity of these instruments. PacifiCorp has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 – Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that PacifiCorp has the ability to access at the measurement date.
- Level 2 – Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 – Unobservable inputs reflect PacifiCorp's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. PacifiCorp develops these inputs based on the best information available, including its own data.

The following table presents PacifiCorp's assets and liabilities recognized on the Consolidated Balance Sheet and measured at fair value on a recurring basis as of December 31, 2009 (in millions):

	Input Levels for Fair Value Measurements				
Description	**Level 1**	**Level 2**	**Level 3**	**Other** [(1)]	**Total**
Assets [(2)]**:**					
Investments in available-for-sale securities:					
Money market mutual funds [(3)]	$ 123	$ -	$ -	$ -	$ 123
Debt securities	1	33	-	-	34
Equity securities	36	8	-	-	44
Commodity derivatives	-	285	6	(140)	151
	$ 160	$ 326	$ 6	$ (140)	$ 352
Liabilities:					
Commodity derivatives	$ -	$ (274)	$ (386)	$ 165	$ (495)

(1) Primarily represents netting under master netting arrangements and a net cash collateral receivable of $25 million.

(2) Refer to Note 11 for information regarding the fair value of pension and other postretirement benefit plan assets as it is excluded from these amounts.

(3) Amounts are included in cash and cash equivalents, other current assets, and investments and other assets on the Consolidated Balance Sheet. The fair value of these money market mutual funds approximates cost.

The following table presents PacifiCorp's assets and liabilities recognized on the Consolidated Balance Sheet and measured at fair value on a recurring basis as of December 31, 2008 (in millions):

	Input Levels for Fair Value Measurements				
Description	**Level 1**	**Level 2**	**Level 3**	**Other [1]**	**Total**
Assets [2]:					
Investments in available-for-sale securities:					
Money market mutual funds [3]	$ 51	$ -	$ -	$ -	$ 51
Debt securities	-	42	-	-	42
Equity securities	30	6	-	-	36
Commodity derivatives	-	474	88	(302)	260
	$ 81	$ 522	$ 88	$ (302)	$ 389
Liabilities:					
Commodity derivatives	$ -	$ (485)	$ (496)	$ 361	$ (620)

(1) Primarily represents netting under master netting arrangements and a net cash collateral receivable of $82 million.

(2) Does not include investments in either pension or other postretirement benefit plan assets.

(3) Amounts are included in cash and cash equivalents, other current assets, and investments and other assets on the Consolidated Balance Sheet. The fair value of these money market mutual funds approximates cost.

PacifiCorp's investments in money market mutual funds and debt and equity securities are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics.

When available, the fair value of derivative contracts is determined using unadjusted quoted prices for identical contracts on the applicable exchange in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves derived from market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first six years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first six years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on significant unobservable inputs. Refer to Note 7 for further discussion regarding PacifiCorp's risk management and hedging activities.

Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve. Option components are valued using Black-Scholes-type models, such as European option, Asian option, spread option and best-of option, with the appropriate forward price curve and other inputs.

The following table reconciles the beginning and ending balances of PacifiCorp's commodity derivative assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	2009	2008
Beginning balance	$ (408)	$ (311)
Changes in fair value recognized in regulatory assets	(5)	(98)
Purchases, sales, issuances and settlements	56	(12)
Net transfers into or out of Level 3	(23)	13
Ending balance	$ (380)	$ (408)

PacifiCorp's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of PacifiCorp's long-term debt has been estimated based on quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying amount of PacifiCorp's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying amount and estimated fair value of PacifiCorp's long-term debt as of December 31 (in millions):

	2009		2008	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt	$ 6,357	$ 6,843	$ 5,503	$ 5,769

(7) Risk Management and Hedging Activities

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. PacifiCorp is principally exposed to electricity and natural gas commodity price risk as it has an obligation to serve retail customer load in its regulated service territories. PacifiCorp's load and generation assets represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Electricity and natural gas prices are subject to wide price swings as supply and demand for these commodities are impacted by, among many other unpredictable items, changing weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt, commercial paper and future debt issuances. PacifiCorp does not engage in a material amount of proprietary trading activities.

PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its commodity risk, PacifiCorp uses commodity derivative contracts, including forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates and by monitoring market changes in interest rates. PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to effectively modify PacifiCorp's exposure to interest rate risk. No interest rate derivatives were in place during the periods presented. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in PacifiCorp's accounting policies related to derivatives. Refer to Notes 2 and 6 for additional information on derivative contracts.

The following table, which excludes contracts that qualify for the normal purchases and normal sales exception afforded by GAAP, summarizes the fair value of PacifiCorp's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheet as of December 31, 2009 (in millions):

	Balance Sheet Locations				
	Derivative Assets		Derivative Liabilities		
	Current	Noncurrent	Current	Noncurrent	Total
Not Designated as Hedging Contracts [(1)(2)]:					
Commodity assets	$ 191	$ 61	$ 8	$ 31	$ 291
Commodity liabilities	(29)	(17)	(142)	(472)	(660)
Total	162	44	(134)	(441)	(369)
Designated as Cash Flow Hedging Contracts:					
Commodity assets	-	-	-	-	-
Commodity liabilities	-	-	-	-	-
Total	-	-	-	-	-
Total derivatives	162	44	(134)	(441)	(369)
Cash collateral receivable (payable)	(54)	(1)	49	31	25
Total derivatives – net basis	$ 108	$ 43	$ (85)	$ (410)	$ (344)

(1) Derivative contracts within these categories are subject to master netting arrangements and are presented on a net basis in the Consolidated Balance Sheet.

(2) The majority of PacifiCorp's commodity derivatives not designated as hedging contracts are expected to be included in regulated rates and as of December 31, 2009, a net regulatory asset of $367 million was recorded related to the net derivative liabilities of $369 million.

Not Designated as Hedging Contracts

For PacifiCorp's commodity derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as net regulatory assets. The following table reconciles the beginning and ending balances of PacifiCorp's net regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets, as well as amounts reclassified to earnings for the year ended December 31(in millions):

	2009
Beginning balance	$ 442
Changes in fair value recognized in net regulatory assets	(74)
Gains reclassified to earnings – operating revenue	222
Losses reclassified to earnings – energy costs	(223)
Ending balance	$ 367

For PacifiCorp's derivatives not designated as hedging contracts and for which changes in fair value are not recorded as a net regulatory asset or liability, unrealized gains and losses are recorded on the Consolidated Statements of Operations as revenue for sales contracts, energy costs and operating expenses for purchases contracts and electricity and natural gas swap contracts and interest expense for interest rate derivatives. The following table summarizes the pre-tax gains (losses) included within the Consolidated Statement of Operations associated with PacifiCorp's derivative contracts not designated as hedging contracts and not recorded as a net regulatory asset or liability for the year ended December 31 (in millions):

	2009
Commodity derivatives:	
Operating revenue	$ 5
Energy costs	1
Operations and maintenance	-
Total	$ 6

Designated as Cash Flow Hedging Contracts

PacifiCorp uses derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices. The gains and losses on these derivative contracts are recognized in other comprehensive income. Derivative contracts accounted for as cash flow hedges were not material for the year ended December 31, 2009. Hedge ineffectiveness is recognized in income as operating revenue or energy costs depending upon the nature of the item being hedged. For the years ended December 31, 2009, 2008 and 2007, hedge ineffectiveness was insignificant.

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2009
Commodity contracts:		
Electricity sales	Megawatt hours	(22)
Natural gas purchases	Decatherms	201
Fuel purchases	Gallons	14

Credit Risk

PacifiCorp extends unsecured credit to other utilities, energy marketers, financial institutions and other market participants in conjunction with wholesale energy supply and marketing activities. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on their contractual obligations to make or take delivery of electricity, natural gas or other commodities and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with the counterparty.

PacifiCorp analyzes the financial condition of each significant wholesale counterparty before entering into any transactions, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of wholesale counterparties, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtaining third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed interest fees for delayed payments. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain derivative contracts contain provisions that require PacifiCorp to maintain specific credit ratings from one or more of the major credit rating agencies on its unsecured debt. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2009, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled \$353 million as of December 31, 2009, for which PacifiCorp had posted collateral of \$80 million. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2009, PacifiCorp would have been required to post \$159 million of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings or other factors.

(8) Short-Term Borrowings and Other Financing Agreements

PacifiCorp has two unsecured revolving credit facilities totaling $1.395 billion. The credit facilities include a fixed or variable borrowing option for which rates vary based on the borrowing option and PacifiCorp's credit ratings for its senior unsecured long-term debt securities. These facilities support PacifiCorp's commercial paper program and certain variable-rate tax-exempt bond obligations. As of December 31, 2009, PacifiCorp had letters of credit issued under the credit agreements totaling $220 million to support variable-rate tax-exempt bond obligations and had no borrowings outstanding under its credit facilities. In addition, the credit facilities support $38 million of unenhanced variable-rate tax-exempt bond obligations as of December 31, 2009. As of December 31, 2008, PacifiCorp had outstanding commercial paper borrowings of $85 million at an average rate of 1%. Each revolving credit agreement requires that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization at no time exceed 0.65 to 1.0. PacifiCorp was in compliance with the covenants of its revolving credit and the other above-noted financing agreements as of December 31, 2009.

The following table summarizes PacifiCorp's availability under its two unsecured revolving credit facilities as of December 31, 2009 (in millions):

Total unsecured revolving credit facilities	$	1,395
Less:		
Short-term debt (credit facility borrowings or commercial paper)		-
Support for unenhanced variable-rate tax-exempt bond obligations		(38)
Letters of credit supporting variable-rate tax-exempt bond obligations		(220)
Net unsecured revolving credit facilities available	$	1,137
Total bank commitment amounts under credit agreements:		
January 1, 2010 through July 6, 2011	$	1,395
July 7, 2011 through July 6, 2012		1,355
July 7, 2012 through October 23, 2012		1,265
October 24, 2012 through July 6, 2013		630

As of December 31, 2009, PacifiCorp had approximately $15 million of additional letters of credit issued on its behalf to provide credit support for certain transactions as required by third parties. These committed bank arrangements were all fully available as of December 31, 2009 and have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

(9) Long-Term Debt and Capital Lease Obligations

PacifiCorp's long-term debt and capital lease obligations were as follows as of December 31 (in millions):

	2009			2008	
	Par Value	Amount	Average Interest Rate	Amount	Average Interest Rate
First mortgage bonds:					
5.0% to 9.2%, due through 2014	$ 1,047	$ 1,047	6.5%	$ 1,185	6.6%
5.5% to 8.7%, due 2015 to 2019	862	858	5.6	511	5.7
6.7% to 8.5%, due 2021 to 2023	324	324	7.7	324	7.7
6.7% due 2026	100	100	6.7	100	6.7
5.9% to 7.7% due 2031 to 2034	500	499	7.0	499	7.0
5.3% to 6.4%, due 2035 to 2039	2,800	2,790	6.0	2,145	6.0
Tax-exempt bond obligations:					
Variable rates, due 2013 (1)	41	41	0.3	41	0.8
Variable rates, due 2014 to 2025	325	325	0.5	325	1.1
Variable rates, due 2024 (1)	176	176	0.2	176	0.9
Variable rates, due 2014 to 2025 (1) (2)	113	113	3.8	113	3.8
5.6% to 5.7%, due 2021 to 2023 (1)	71	71	5.6	71	5.6
6.2% due 2030	13	13	6.2	13	6.2
Total long-term debt	6,372	6,357		5,503	
Capital lease obligations:					
8.8% to 14.8%, due through 2036	59	59	11.7	65	11.6
Total long-term debt and capital lease obligations	$ 6,431	$ 6,416		$ 5,568	

Reflected as:

	2009	2008
Current portion of long-term debt and capital lease obligations	$ 16	$ 144
Long-term debt and capital lease obligations	6,400	5,424
Total long-term debt and capital lease obligations	$ 6,416	$ 5,568

(1) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the tax-exempt bond obligations.

(2) Interest rates currently fixed for a term at 3.4% to 4.1%, with $45 million and $68 million scheduled to reset in 2010 and 2013, respectively.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $19.8 billion of the eligible assets (based on original cost) of PacifiCorp were subject to the lien of the mortgage as of December 31, 2009.

In January 2009, PacifiCorp issued $350 million of its 5.50% First Mortgage Bonds due January 15, 2019 and $650 million of its 6.00% First Mortgage Bonds due January 15, 2039. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes.

In September 2008, PacifiCorp acquired $216 million of its insured variable-rate tax-exempt bond obligations due to the significant reduction in market liquidity for insured variable-rate obligations. In November 2008, the associated insurance and related standby bond purchase agreements were terminated and these variable-rate long-term debt obligations were remarketed with credit enhancement and liquidity support provided by $220 million of letters of credit issued under PacifiCorp's two unsecured revolving credit facilities.

In July 2008, PacifiCorp issued $500 million of its 5.65% First Mortgage Bonds due July 15, 2018 and $300 million of its 6.35% First Mortgage Bonds due July 15, 2038.

PacifiCorp has regulatory authority from the OPUC to issue an additional $2.0 billion of long-term debt. Current authority from the Idaho Public Utilities Commission would permit $200 million of additional long-term debt issuances, and PacifiCorp is currently seeking authority for a total of $2.0 billion. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance.

As of December 31, 2009, $5.2 billion of first mortgage bonds were redeemable at PacifiCorp's option at redemption prices dependent upon United States Treasury yields. As of December 31, 2009, $542 million of variable-rate tax-exempt bond obligations and $84 million of fixed-rate tax-exempt bond obligations were redeemable at PacifiCorp's option at par. The remaining long-term debt was not redeemable as of December 31, 2009.

As of December 31, 2009, PacifiCorp had $517 million of letters of credit available to provide credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $504 million plus interest. These committed bank arrangements were fully available as of December 31, 2009 and expire periodically through May 2012.

PacifiCorp's letters of credit generally contain similar covenants and default provisions to those contained in PacifiCorp's revolving credit agreement, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0. PacifiCorp monitors these covenants on a regular basis in order to ensure that events of default will not occur and as of December 31, 2009, PacifiCorp was in compliance with these covenants.

PacifiCorp has entered into long-term agreements that qualify as capital leases and expire at various dates through October 2036 for transportation services, power purchase agreements, real estate and for the use of certain equipment. The transportation services agreements included as capital leases are for the right to use pipeline facilities to provide natural gas to three of PacifiCorp's generating facilities. Net assets accounted for as capital leases of $59 million and $65 million as of December 31, 2009 and 2008, respectively, were included in property, plant and equipment, net in the Consolidated Balance Sheets.

As of December 31, 2009, the annual maturities of long-term debt and capital lease obligations, excluding unamortized discounts, for 2010 and thereafter are as follows (in millions):

	Long-Term Debt	Capital Lease Obligations	Total
2010	$ 14	$ 9	$ 23
2011	587	8	595
2012	17	8	25
2013	261	12	273
2014	253	8	261
Thereafter	5,240	94	5,334
Total	6,372	139	6,511
Unamortized discount	(15)	-	(15)
Amounts representing interest	-	(80)	(80)
Total	$ 6,357	$ 59	$ 6,416

(10) Asset Retirement Obligations

PacifiCorp estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including plan revisions, inflation and changes in the amount and timing of the expected work.

PacifiCorp does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain transmission, distribution and other assets cannot currently be estimated and no amounts are recognized on the accompanying Consolidated Financial Statements other than those included in the regulatory removal cost liability established via approved depreciation rates.

The change in the balance of the total ARO liability, which is included in other current liabilities and other long-term liabilities, is summarized as follows as of December 31 (in millions):

	2009	2008
Balance, January 1	$ 165	$ 185
Additions	3	2
Retirements	(20)	(24)
Change in estimated costs (1)	24	(8)
Accretion	9	10
Balance, December 31	$ 181	$ 165
Reflected as:		
Other current liabilities	$ 15	$ 27
Other long-term liabilities	166	138
	$ 181	$ 165
Investment trusts (2)	$ 81	$ 83

(1) Results from changes in the timing and amounts of estimated cash flows for certain plant and mine reclamation.

(2) Substantially represents PacifiCorp's trust for final reclamation of the Jim Bridger mine, including the noncontrolling interest joint-owner portion. Amount is included in other current assets and investments and other assets on the Consolidated Balance Sheets.

PacifiCorp's coal mining operations are subject to the Surface Mining Control and Reclamation Act of 1977 and similar state statutes that establish operational, reclamation and closure standards that must be met during and upon completion of mining activities. These statutes mandate that mining property be restored consistent with specific standards and the approved reclamation plan. PacifiCorp incurs expenditures for both ongoing and final reclamation. PacifiCorp's ARO liabilities consist principally of mine reclamation obligations for its Jim Bridger mine that were $79 million and $84 million as of December 31, 2009 and 2008, respectively.

Certain of PacifiCorp's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites. For decommissioning, PacifiCorp is committed to pay a proportionate share of the decommissioning costs based upon its ownership percentage, or in the case of mine reclamation obligations, PacifiCorp has committed to pay a proportionate share of mine reclamation costs based on the amount of coal purchased by PacifiCorp. In the event of default by any of the other joint participants, PacifiCorp potentially may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

(11) Employee Benefit Plans

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees and also provides certain postretirement healthcare and life insurance benefits through various plans for eligible retirees. In addition, PacifiCorp sponsors a defined contribution 401(k) employee savings plan (the "401(k) Plan"). Non-union employees hired on or after January 1, 2008 and certain union new hires are not eligible to participate in the PacifiCorp Retirement Plan (the "Retirement Plan"). These employees are eligible to receive enhanced benefits under the 401(k) Plan.

Pension and Other Postretirement Benefit Plans

PacifiCorp's pension plans include a non-contributory defined benefit pension plan, the Retirement Plan; the Supplemental Executive Retirement Plan (the "SERP"); and certain joint trust union plans to which PacifiCorp contributes on behalf of certain bargaining units. All non-union Retirement Plan participants, as well as certain union participants, earn benefits based on a cash balance formula. Certain union employees covered under the Retirement Plan continue to earn benefits based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments to reflect benefits estimated to be received from social security.

The cost of other postretirement benefits, including healthcare and life insurance benefits for eligible retirees, is accrued over the active service period of employees. PacifiCorp funds these other postretirement benefits through a combination of funding vehicles. PacifiCorp also contributes to joint trust union plans for postretirement benefits offered to certain bargaining units.

Measurement Date Change

PacifiCorp adopted the measurement date provisions included in the authoritative guidance for retirement benefits at December 31, 2008, which requires that an employer measure plan assets and benefit obligations at the end of the employer's fiscal year. Effective December 31, 2008, PacifiCorp changed its measurement date from September 30 to December 31 and recorded a $14 million transitional adjustment. The components of the measurement date change transitional adjustment were as follows on a pre-tax basis (in millions):

	Pension	Other Postretirement	Total
Service cost	$ 7	$ 2	$ 9
Interest cost	16	8	24
Expected return on plan assets	(18)	(7)	(25)
Net amortization	2	4	6
Total	$ 7	$ 7	$ 14

The $14 million transitional adjustment included $12 million recorded as an increase in regulatory assets for the portion considered probable of inclusion in regulated rates and $2 million recorded as a reduction ($1 million after-tax) in retained earnings for the portion not considered probable of inclusion in regulated rates. The $12 million increase to regulatory assets is being amortized over three to 10 years based on agreements with various state regulatory commissions. The recognition of service cost, interest cost and expected return on plan assets, totaling $8 million, resulted in an increase in pension and other postretirement liabilities. The $6 million net amortization represents recognition of prior service cost, net transition obligation and actuarial net loss and resulted in a reduction in regulatory assets.

Curtailments

In August 2008, non-union employee participants in the Retirement Plan were offered the option to continue to receive pay credits in their current cash balance formula of the Retirement Plan or receive equivalent fixed contributions to the 401(k) Plan. The election was effective January 1, 2009 and resulted in the recognition of a $38 million curtailment gain. PacifiCorp recorded $36 million of the curtailment gain as a reduction to regulatory assets as of December 31, 2008, representing the amount to be returned to customers in rates. The reduction to regulatory assets is being amortized over a period of three to 10 years based on agreements with various state regulatory commissions.

Effective December 31, 2007, Local Union No. 659 of the International Brotherhood of Electrical Workers ("Local 659") elected to cease participation in the Retirement Plan and participate only in the 401(k) Plan with enhanced benefits. As a result of this election, the Local 659 participants' Retirement Plan benefits were frozen as of December 31, 2007. This change resulted in a $2 million curtailment gain that was recorded as a reduction to regulatory assets as of December 31, 2008 based on the requirement to return the amount to customers in rates. The reduction to regulatory assets is being amortized over a period of three to 10 years based on agreements with various state regulatory commissions. Also as a result of this change, PacifiCorp's pension liability and regulatory assets each decreased by $13 million.

Effective March 31, 2010, Utility Workers Union of America Local Union No. 127 ("Local 127") will cease participation in the Retirement Plan and participate only in the 401(k) Plan with enhanced benefits. As a result, the Local 127 participants' Retirement Plan benefits will be frozen on March 31, 2010. The impacts of this change are not expected to significantly impact PacifiCorp's consolidated financial results.

Change in Benefit Formula

Effective June 1, 2007, PacifiCorp switched from a traditional final-average-pay formula for the Retirement Plan to a cash balance formula for its non-union employees. As a result of the change, benefits under the traditional final-average-pay formula were frozen as of May 31, 2007 for non-union employees, and PacifiCorp's pension liability and regulatory assets each decreased by $111 million.

Net Periodic Benefit Cost

For purposes of calculating the expected return on plan assets, a market-related value is used. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning after the first year in which they occur.

Net periodic benefit cost for the plans included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2009	2008 [2]	2007	2009	2008 [2]	2007
Service cost [1]	$ 16	$ 27	$ 29	$ 5	$ 7	$ 7
Interest cost	71	67	71	33	33	33
Expected return on plan assets	(70)	(72)	(68)	(29)	(28)	(26)
Net amortization	10	7	23	12	15	19
Net amortization of regulatory assets	(8)	-	-	1	-	-
Cost of termination benefits	-	-	1	-	-	-
Curtailment gain	-	(2)	-	-	-	-
Net periodic benefit cost	$ 19	$ 27	$ 56	$ 22	$ 27	$ 33

(1) Service cost excludes $13 million, $13 million and $12 million of contributions to the joint trust union plans during the years ended December 31, 2009, 2008 and 2007, respectively.

(2) Excludes the impact of the measurement date change and the portion of the curtailment gains required to be returned to customers in rates. Refer to "Measurement Date Change" and "Curtailments" above.

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2009	2008	2009	2008
Plan assets at fair value, beginning of year	$ 692	$ 963	$ 284	$ 378
Employer contributions	54	70	24	42
Participant contributions	-	-	9	14
Actual return on plan assets	160	(224)	70	(103)
Benefits paid	(81)	(117)	(37)	(47)
Plan assets at fair value, end of year	$ 825	$ 692	$ 350	$ 284

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2009	2008	2009	2008
Benefit obligation, beginning of year	$ 1,070	$ 1,111	$ 489	$ 536
Service cost (1)	16	34	5	9
Interest cost (1)	71	83	33	41
Participant contributions	-	-	9	14
Plan amendments	(1)	(7)	(4)	(12)
Curtailment	-	(13)	-	-
Actuarial loss (gain)	124	(21)	47	(56)
Benefits paid, net of Medicare subsidy	(81)	(117)	(34)	(43)
Cost of termination benefits	-	-	-	-
Benefit obligation, end of year	$ 1,199	$ 1,070	$ 545	$ 489
Accumulated benefit obligation, end of year	$ 1,178	$ 1,048		

(1) Included in the pension and other postretirement liabilities in connection with the measurement date change in 2008 was additional service cost of $7 million and $2 million and additional interest cost of $16 million and $8 million for the pension and other postretirement benefit plans, respectively.

The funded status of the plans and the amounts recognized on the Consolidated Balance Sheets are as follows as of December 31 (in millions):

	Pension		Other Postretirement	
	2009	2008	2009	2008
Plan assets at fair value, end of year	$ 825	$ 692	$ 350	$ 284
Less — Benefit obligation, end of year	1,199	1,070	545	489
Funded status	$ (374)	$ (378)	$ (195)	$ (205)
Amounts recognized on the Consolidated Balance Sheets:				
Other current liabilities	$ (4)	$ (4)	$ -	$ -
Other long-term liabilities	(370)	(374)	(195)	(205)
Amounts recognized	$ (374)	$ (378)	$ (195)	$ (205)

The SERP has no plan assets; however, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in the Rabbi trust, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $39 million and $38 million as of December 31, 2009 and 2008, respectively. These assets are not included in the plan assets in the above table, but are reflected on the Consolidated Balance Sheets. The portion of the pension plans' projected benefit obligation related to the SERP was $55 million and $50 million as of December 31, 2009 and 2008, respectively. The SERP's accumulated benefit obligation totaled $55 million and $50 million as of December 31, 2009 and 2008, respectively.

Unrecognized Amounts

The portion of the funded status of the plans not yet recognized in net periodic benefit cost is as follows as of December 31 (in millions):

	Pension		Other Postretirement	
	2009	2008	2009	2008
Amounts not yet recognized as components of net periodic benefit cost:				
Net loss	$ 523	$ 508	$ 135	$ 128
Prior service (credit) cost	(60)	(68)	-	1
Net transition obligation	-	-	29	45
Regulatory deferrals [(1)]	(24)	(32)	5	6
Total	$ 439	$ 408	$ 169	$ 180

(1) Consists of amounts related to the portion of the curtailment gains and the measurement date change transitional adjustment that are considered probable of inclusion in regulated rates.

A reconciliation of the beginning and ending balances of amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2009 and 2008 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss, Net	Total
Pension			
Balance, January 1, 2008	$ 132	$ 6	$ 138
Net loss (gain) arising during the year	293	(2)	291
Prior service credit arising during the year	(7)	-	(7)
Curtailment gains	(11)	-	(11)
Measurement date change	6	-	6
Net amortization [(1)]	(9)	-	(9)
Total	272	(2)	270
Balance, December 31, 2008	$ 404	$ 4	$ 408
Balance, January 1, 2009	$ 404	$ 4	$ 408
Net loss arising during the year	29	5	34
Prior service credit arising during the year	(1)	-	(1)
Net amortization	(2)	-	(2)
Total	26	5	31
Balance, December 31, 2009	$ 430	$ 9	$ 439

	Regulatory Asset	Deferred Income Taxes	Total
Other Postretirement			
Balance, January 1, 2008	$ 95	$ 27	$ 122
Net loss (gain) arising during the year	91	(7)	84
Prior service credit arising during the year	(13)	-	(13)
Measurement date change	6	-	6
Net amortization [(1)]	(19)	-	(19)
Total	65	(7)	58
Balance, December 31, 2008	$ 160	$ 20	$ 180
Balance, January 1, 2009	$ 160	$ 20	$ 180
Net loss arising during the year	4	3	7
Prior service credit arising during the year	(1)	-	(1)
Transition obligation credit arising during the year	(3)	-	(3)
Net amortization	(14)	-	(14)
Total	(14)	3	(11)
Balance, December 31, 2009	$ 146	$ 23	$ 169

(1) Included in the net amortization for 2008 was $2 million and $4 million for the pension and other postretirement benefit plans, respectively, in connection with the measurement date change in 2008.

The net loss, prior service credit, net transition obligation and regulatory deferrals that will be amortized in 2010 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Net Transition Obligation	Regulatory Deferrals	Total
Pension	$ 32	$ (9)	$ -	$ (9)	$ 14
Other postretirement	4	-	10	1	15
Total	$ 36	$ (9)	$ 10	$ (8)	$ 29

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows for the years ended December 31:

	Pension			Other Postretirement		
	2009	2008	2007	2009	2008	2007
Benefit obligations as of the measurement date:						
Discount rate	5.80%	6.90%	6.30%	5.85%	6.90%	6.45%
Rate of compensation increase	3.00	3.50	4.00	N/A	N/A	N/A
Net benefit cost for the period ended:						
Discount rate	6.90%	6.30%	5.76%	6.90%	6.45%	6.00%
Expected return on plan assets	7.75	7.75	8.00	7.75	7.75	8.00
Rate of compensation increase	3.50	4.00	4.00	N/A	N/A	N/A

In establishing its assumption as to the expected return on plan assets, PacifiCorp reviews the expected asset allocation and develops return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

Assumed healthcare cost trend rates were as follows as of December 31:

	2009	2008
Healthcare cost trend rate assumed for next year ─ under 65	8%	8%
Healthcare cost trend rate assumed for next year ─ over 65	8	6
Rate that the cost trend rate gradually declines to	5	5
Year that the rate reaches the rate it is assumed to remain at ─ under 65	2016	2012
Year that the rate reaches the rate it is assumed to remain at ─ over 65	2016	2010

A one-percentage-point change in assumed healthcare cost trend rates would have the following effects (in millions):

	Increase (Decrease)	
	One Percentage-Point Increase	One Percentage-Point Decrease
Effect on total service and interest cost	$ 3	$ (2)
Effect on other postretirement benefit obligation	31	(26)

Contributions and Benefit Payments

Employer contributions to the pension, other postretirement benefit and joint trust union plans are expected to be $109 million, $25 million and $13 million, respectively, during 2010. Funding to PacifiCorp's Retirement Plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. PacifiCorp's funding policy for its other postretirement benefit plans is to contribute an amount equal to the sum of the net periodic benefit cost and the Medicare subsidies expected to be earned during the period.

The Plan's expected benefit payments to participants for its pension and other postretirement benefit plans for 2010 through 2014 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments			
		Other Postretirement		
	Pension	Gross	Medicare Subsidy	Net of Subsidy
2010	$ 99	$ 34	$ (3)	$ 31
2011	102	37	(3)	34
2012	104	39	(4)	35
2013	111	41	(4)	37
2014	116	43	(5)	38
2015 – 2019	525	239	(32)	207

Plan Assets

Investment Policy and Asset Allocation

PacifiCorp's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of fixed income securities, equity securities and other alternative investments. Maturities for fixed income securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment advisors to manage plan investments within the parameters outlined by the PacifiCorp Pension Committee. PacifiCorp manages the investment portfolio in line with the investment policy with sufficient liquidity to meet near-term benefit payments. The return on assets assumption for each plan is based on a weighted-average of the expected performance for the types of assets in which the plans invest.

PacifiCorp's target allocations (percentage of plan assets) for the pension and other postretirement benefit plan assets are as follows as of December 31, 2009:

	Pension(1)	Other Postretirement(1)
	%	%
Cash and cash equivalents	0 – 1	0 – 1
Equity securities (2)	53 – 57	61 – 65
Fixed-income securities (2)	33 – 37	33 – 37
Limited partnership interests	8 – 12	1 – 3

(1) PacifiCorp's pension plan trust includes a separate account that is used to fund benefits for the other postretirement benefit plan. In addition to this separate account, the assets for the other postretirement benefit plans are held in two Voluntary Employees' Beneficiaries Association ("VEBA") trusts, each of which has its own investment allocation strategies. Target allocations for the other postretirement benefit plans include the separate account of the pension plan trust and the two VEBA trusts.

(2) For purposes of target allocation percentages, investment funds have been allocated based on the underlying investments in equity and fixed-income securities.

The following table presents the fair value of PacifiCorp's plan assets, by major category, as of December 31, 2009 (in millions):

	Input Levels for Fair Value Measurements			
	Level 1 [(1)]	Level 2 [(1)]	Level 3 [(1)]	Total
Pension				
Cash and cash equivalents	$ -	$ 4	$ -	$ 4
Fixed-income securities:				
United States government obligations	20	-	-	20
Corporate obligations	-	44	-	44
International government obligations	-	65	-	65
Municipal obligation	-	2	-	2
Agency, asset and mortgage-backed obligations	-	43	-	43
Equity securities:				
United States equity securities	296	-	-	296
International equity securities	4	-	-	4
Investment funds [(2)]	95	168	-	263
Limited partnership interests [(3)]	-	-	80	80
Total [(4)]	$ 415	$ 326	$ 80	$ 821
Other postretirement				
Cash and cash equivalents	$ 3	$ -	$ -	$ 3
Fixed-income securities:				
United States government obligations	2	-	-	2
Corporate obligations	-	4	-	4
International government obligations	-	6	-	6
Agency, asset and mortgage-backed obligations	-	4	-	4
Equity securities:				
United States equity securities	115	-	-	115
International equity securities	2	-	-	2
Investment funds [(2)]	101	104	-	205
Limited partnership interests [(3)]	-	-	8	8
Total [(4)]	$ 223	$ 118	$ 8	$ 349

(1) Refer to Note 6 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds for the pension and other postretirement benefit plans include investments of 14% and 29%, respectively, in United States equity securities; 49% and 23%, respectively, in international equity securities; 13% and 17%, respectively, in United States government obligations; 8% and 10%, respectively, in corporate obligations; 9% and 11%, respectively, in international government obligations; and 7% and 10%, respectively, in agency, asset and mortgage-backed obligations.

(3) Limited partnership interests include several private equity funds that invest primarily in buyout, growth equity and venture capital.

(4) Net receivables of $4 million and $1 million, respectively, related to the pension and other postretirement benefit plans are excluded from the fair value measurement hierarchy.

When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. When observable market data is not available, the fair value is determined using unobservable inputs, such as estimated future cash flows, purchase multiples paid in other comparable third-party transactions or other information. Investments in limited partnerships are valued at estimated fair value based on the Plan's proportionate share of the partnerships' fair value as recorded in the partnerships' most recently available financial statements adjusted for recent activity and forecasted returns. The fair values recorded in the partnerships' financial statements are generally determined based on closing public market prices for publicly traded securities and as determined by the general partners for other investments based on factors including estimated future cash flows, purchase multiples paid in other comparable third-party transactions, comparable public company trading multiples and other information.

The following table reconciles the beginning and ending balances of PacifiCorp's plan assets measured at fair value using significant Level 3 inputs for the year ended December 31, 2009 (in millions):

	Limited Partnership Interests	
	Pension	Other Postretirement
Balance, January 1, 2009	$ 78	$ 7
Actual return on plan assets still held at period end [(1)]	5	1
Purchases, sales, issuances and settlements	(3)	-
Balance, December 31, 2009	$ 80	$ 8

(1) Actual return on pension plan assets for limited partnership interests consisted of unrealized appreciation of $5 million related to assets held at December 31, 2009.

Defined Contribution Plan

PacifiCorp's 401(k) Plan covers substantially all employees. PacifiCorp's contributions are based primarily on each participant's level of contribution and cannot exceed the maximum allowable for tax purposes to the 401(k) Plan. PacifiCorp's contributions were $34 million, $23 million and $19 million during the years ended December 31, 2009, 2008 and 2007, respectively. As previously described, certain participants now receive enhanced benefits in the 401(k) Plan and no longer accrue benefits in the Retirement Plan.

(12) Income Taxes

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2009	2008	2007
Current:			
Federal	$ (417)	$ (64)	$ 162
State	6	(6)	19
Total	(411)	(70)	181
Deferred:			
Federal	619	276	41
State	30	36	6
Total	649	312	47
Investment tax credits	(4)	(4)	(8)
Total income tax expense	$ 234	$ 238	$ 220

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense is as follows for the years ended December 31:

	2009	2008	2007
Federal statutory tax rate	35%	35%	35%
State taxes, net of federal benefit	3	3	3
Tax credits [1]	(6)	(5)	(3)
Other	(2)	1	(2)
Effective income tax rate	30%	34%	33%

(1) Primarily attributable to the impact of federal renewable electricity production tax credits related to qualifying wind-powered generating facilities that extend 10 years from the date the facilities were placed in service.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2009	2008
Deferred tax assets:		
Regulatory liabilities	$ 326	$ 319
Employee benefits	247	249
Derivative contracts	140	169
Other	169	153
	882	890
Deferred tax liabilities:		
Property, plant and equipment	(2,599)	(1,940)
Regulatory assets	(838)	(881)
Other	(31)	(20)
	(3,468)	(2,841)
Net deferred tax liability	$ (2,586)	$ (1,951)
Reflected as:		
Deferred income taxes – current assets	$ 39	$ 74
Deferred income taxes – non-current liabilities	(2,625)	(2,025)
	$ (2,586)	$ (1,951)

The sale of PacifiCorp to MEHC on March 21, 2006 triggered certain tax related events that remain unsettled. PacifiCorp does not believe that the tax, if any, arising from the ultimate settlement of these events will have a material impact on its consolidated financial results.

As of December 31, 2009 and 2008, PacifiCorp had a net liability of $75 million and a net asset of $13 million, respectively, for uncertain tax positions. As of December 31, 2009 and 2008, the net liability for uncertain tax positions included $6 million and the net asset for uncertain tax positions included $14 million, respectively, of tax positions that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect PacifiCorp's effective tax rate. The current portion of uncertain tax positions is included in accrued taxes and the non-current portion is included in other long-term liabilities in the Consolidated Balance Sheets.

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through the 2003 tax year. In most cases, state jurisdictions have closed their examinations of PacifiCorp's income tax returns through 1993.

PacifiCorp adopted authoritative guidance related to uncertain tax positions (included in ASC Topic 740, "Income Taxes") effective January 1, 2007 and had a net asset of $22 million for uncertain tax positions. PacifiCorp recognized a net increase in the asset of $22 million as a cumulative effect of adopting this guidance, which was offset by increases in beginning retained earnings of $13 million and deferred income tax liabilities of $9 million on the Consolidated Balance Sheets.

(13) Commitments and Contingencies

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material effect on its consolidated financial results. PacifiCorp is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts and are described below.

Legal Matters

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Wyoming state opacity standards at PacifiCorp's Jim Bridger generating facility in Wyoming. Under Wyoming state requirements, which are part of the Jim Bridger generating facility's Title V permit and are enforceable by private citizens under the federal Clean Air Act, a potential source of pollutants such as a coal-fired generating facility must meet minimum standards for opacity, which is a measurement of light that is obscured in the flue of a generating facility. The complaint alleged thousands of violations of asserted six-minute compliance periods and sought an injunction ordering the Jim Bridger generating facility's compliance with opacity limits, civil penalties of $32,500 per day per violation and the plaintiffs' costs of litigation. In August 2009, the court ruled on a number of summary judgment motions by which it determined that the plaintiffs have sufficient legal standing to proceed with their complaint and that all other issues raised in the summary judgment motions will be resolved at trial. In February 2010, PacifiCorp, the Sierra Club and the Wyoming Outdoor Council reached an agreement in principle to settle all outstanding claims in the action. The settlement will be memorialized in a consent decree to be filed with the Environmental Protection Agency for review and also with the court for review and approval. If approved by the court as expected, the settlement is not expected to have a material impact on PacifiCorp's consolidated financial results.

Environmental Regulation

Environmental Matters

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. PacifiCorp believes it is in material compliance with current environmental requirements.

New Source Review

As part of an industry-wide investigation to assess compliance with the New Source Review ("NSR") and Prevention of Significant Deterioration ("PSD") provisions, the United States Environmental Protection Agency (the "EPA") has requested from numerous utilities information and supporting documentation regarding their capital projects for various generating facilities. Between 2001 and 2003, PacifiCorp responded to requests for information relating to its capital projects at its generating facilities, and it has been engaged in periodic discussions with the EPA over several years regarding its historical projects and their compliance with NSR and PSD provisions. An NSR enforcement case against another utility has been decided by the United States Supreme Court, holding that an increase in annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. PacifiCorp could be required to install additional emissions controls, and incur additional costs and penalties, in the event it is determined that PacifiCorp's historical projects did not meet all regulatory requirements. The impact of these additional emissions controls, costs and penalties, if any, on PacifiCorp's consolidated financial results cannot be determined at this time.

Accrued Environmental Costs

PacifiCorp is fully or partly responsible for environmental remediation at various contaminated sites, including sites that are or were part of PacifiCorp's operations and sites owned by third parties. PacifiCorp accrues environmental remediation expenses when the expenses are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on many factors, including changing laws and regulations, advancements in environmental technologies, the quality of available site-specific information, site investigation results, expected remediation or settlement timelines, PacifiCorp's proportionate responsibility, contractual indemnities and coverage provided by insurance policies. The liability recorded as of December 31, 2009 and 2008 was $18 million and $26 million, respectively, and is included in other current liabilities and other long-term liabilities on the Consolidated Balance Sheets. Environmental remediation liabilities that separately result from the normal operation of long-lived assets and that are legal obligations associated with the retirement of those assets are separately accounted for as AROs.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 47 generating facilities with an aggregate facility net owned capacity of 1,158 MW. The Federal Energy Regulatory Commission (the "FERC") regulates 98% of the net capacity of this portfolio through 16 individual licenses, which typically have terms of 30 to 50 years. PacifiCorp expects to incur ongoing operating and maintenance expense and capital expenditures associated with the terms of its renewed hydroelectric licenses and settlement agreements, including natural resource enhancements. PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses. Substantially all of PacifiCorp's remaining hydroelectric generating facilities are operating under licenses that expire between 2030 and 2058.

Klamath Hydroelectric System – Klamath River, Oregon and California

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 170-MW Klamath hydroelectric system in anticipation of the March 2006 expiration of the existing license. PacifiCorp is currently operating under an annual license issued by the FERC and expects to continue operating under annual licenses until the relicensing process is complete or the system's four mainstem dams are removed. As part of the relicensing process, the FERC is required to perform an environmental review and in November 2007, the FERC issued its final environmental impact statement. The United States Fish and Wildlife Service and the National Marine Fisheries Service issued final biological opinions in December 2007 analyzing the Klamath hydroelectric system's impact on endangered species under a new FERC license consistent with the FERC staff's recommended license alternative and terms and conditions issued by the United States Departments of the Interior and Commerce. These terms and conditions include construction of upstream and downstream fish passage facilities at the Klamath hydroelectric system's four mainstem dams. Prior to the FERC issuing a final license, PacifiCorp is required to obtain water quality certifications from Oregon and California. PacifiCorp currently has water quality applications pending in Oregon and California.

In November 2008, PacifiCorp signed a non-binding agreement in principle ("AIP") that laid out a framework for the disposition of PacifiCorp's Klamath hydroelectric system relicensing process, including a path toward potential dam transfer and removal by an entity other than PacifiCorp no earlier than 2020. Subsequent to release of the AIP, negotiations between the parties continued with an expanded group of stakeholders. A final draft of the Klamath Hydroelectric Settlement Agreement ("KHSA") was released in January 2010 for public review. The parties to the KHSA, which include PacifiCorp, the United States Department of the Interior, the United States Department of Commerce, the State of California, the State of Oregon and various other governmental and non-governmental settlement parties, signed the KHSA in February 2010. Federal legislation to endorse and enact provisions of the KHSA is expected to be introduced in the United States Congress in 2010.

Under the terms of the KHSA, the United States Departments of the Interior and Commerce will conduct scientific and engineering studies and consult with state, local and tribal governments and other stakeholders, as appropriate, to determine by March 31, 2012 whether removal of the Klamath hydroelectric system's four mainstem dams will advance restoration of the salmonid fisheries of the Klamath Basin and is in the public interest. This determination will be made by the United States Secretary of the Interior. If it is determined that dam removal should proceed, dam removal is expected to commence no earlier than 2020.

Under the KHSA, PacifiCorp and its customers are protected from uncapped dam removal costs and liabilities. For dam removal to occur, federal legislation consistent with the KHSA must be enacted to provide, among other things, protection for PacifiCorp from all liabilities associated with dam removal activities. In addition, the KHSA limits PacifiCorp's contribution to dam removal costs to no more than $200 million, of which up to $184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. An additional $250 million for dam removal costs is expected to be raised through a California bond measure. If dam removal costs exceed $200 million and if the State of California is unable to raise the funds necessary for dam removal costs, sufficient funds would need to be obtained elsewhere in order for the KHSA and dam removal to proceed.

Actual removal of a facility would occur only after all permits for removal are obtained and the facility and associated land are transferred to a dam removal entity. Prior to potential removal of a facility, the facility will generally continue to operate as it does currently. However, PacifiCorp is responsible for implementing interim measures to provide additional resource protections, water quality improvements, habitat enhancement for aquatic species and increased funding for hatchery operations in the Klamath River Basin.

In July 2009, Oregon's governor signed a bill authorizing PacifiCorp to collect surcharges from its Oregon customers for Oregon's share of the customer contribution for the cost of removing the Klamath hydroelectric system's four mainstem dams. PacifiCorp expects collection from Oregon customers to begin in March 2010. Also in March 2010, PacifiCorp will file with the California Public Utilities Commission to obtain approval to begin collecting a surcharge from its California customers.

As of December 31, 2009 and 2008, PacifiCorp had $67 million and $57 million, respectively, in costs related to the relicensing of the Klamath hydroelectric system included in construction work-in-progress within property, plant and equipment, net in the Consolidated Balance Sheets.

Hydroelectric Commitments

As described above, certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $266 million over the next 10 years related to these licenses.

FERC Issues

FERC Investigation

During 2007, the Western Electricity Coordinating Council (the "WECC") audited PacifiCorp's compliance with several of the reliability standards developed by the North American Electric Reliability Corporation (the "NERC"). In April 2008, PacifiCorp received notice of a preliminary non-public investigation from the FERC and the NERC to determine whether an outage that occurred in PacifiCorp's transmission system in February 2008 involved any violations of reliability standards. In November 2008, PacifiCorp received preliminary findings from the FERC staff regarding its non-public investigation into the February 2008 outage. Also in November 2008, in conjunction with the reliability standards review, the FERC assumed control of certain aspects of the WECC's 2007 audit. PacifiCorp has engaged in discussions with FERC staff regarding findings related to the WECC audit and the non-public investigation. However, PacifiCorp cannot predict the impact of the audit or the non-public investigation on its consolidated financial results at this time.

Northwest Refund Case

In June 2003, the FERC terminated its proceeding relating to the possibility of requiring refunds for wholesale spot-market bilateral sales in the Pacific Northwest between December 2000 and June 2001. The FERC concluded that ordering refunds would not be an appropriate resolution of the matter. In November 2003, the FERC issued its final order denying rehearing. Several market participants, excluding PacifiCorp, filed petitions in the United States Court of Appeals for the Ninth Circuit (the "Ninth Circuit") for review of the FERC's final order. In August 2007, the Ninth Circuit concluded that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest, and that the FERC should not have excluded from the Pacific Northwest refund proceeding purchases of energy in the Pacific Northwest spot market made by the California Energy Resources Scheduling ("CERS") division of the California Department of Water Resources. Without issuing the mandate order, the Ninth Circuit remanded the case to the FERC to (a) address the new market manipulation evidence in detail and account for it in any future orders regarding the award or denial of refunds in the proceedings; (b) include sales to CERS in its analysis; and (c) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the merits of the FERC's November 2003 decision to deny refunds. In April 2009, the Ninth Circuit issued a formal mandate order, completing the remand of the case to the FERC, which has not yet undertaken further action. PacifiCorp cannot predict the future course of this proceeding and its impact on its consolidated financial results, if any, at this time.

Purchase Obligations

PacifiCorp has the following unconditional purchase obligations as of December 31, 2009 that are not reflected on the Consolidated Balance Sheet. Minimum payments required for the years ending December 31 (in millions):

	2010	2011	2012	2013	2014	Thereafter	Total
Purchased electricity	$ 262	$ 165	$ 124	$ 127	$ 98	$ 596	$ 1,372
Fuel	554	366	225	213	207	1,198	2,763
Construction	677	172	32	7	18	99	1,005
Transmission	117	111	101	89	75	775	1,268
Operating leases	5	5	4	4	3	40	61
Other	107	29	10	10	6	43	205
Total commitments	$ 1,722	$ 848	$ 496	$ 450	$ 407	$ 2,751	$ 6,674

Purchased Electricity

As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and exchange agreements. PacifiCorp has several power purchase agreements with wind-powered and other generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric systems under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of system output and for a like percentage of system operating expenses and debt service. These costs are included in energy costs on the Consolidated Statements of Operations. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced. These arrangements accounted for less than 5% of PacifiCorp's 2009, 2008 and 2007 energy sources.

Fuel

PacifiCorp has "take or pay" coal and natural gas contracts that require minimum payments.

Construction

PacifiCorp has an ongoing construction program to meet increased electricity usage, customer growth and system reliability objectives. As of December 31, 2009, PacifiCorp had estimated long-term purchase obligations related to its construction program primarily for the installation of emissions control equipment, certain segments of the Energy Gateway Transmission Expansion Program and for new wind-powered generating facilities. Amounts included in the purchase obligations table above relate to firm commitments. The amounts described below include amounts to which PacifiCorp is not yet firmly committed through a purchase order or other agreement.

PacifiCorp's Energy Gateway Transmission Expansion Program represents a plan to build approximately 2,000 miles of new high-voltage transmission lines, with an estimated cost exceeding $6 billion, primarily in Wyoming, Utah, Idaho, Oregon and the desert Southwest. The plan includes several transmission line segments that will: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse resource areas, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area and the Western United States. Proposed transmission line segments are re-evaluated to ensure maximum benefits and timing before committing to move forward with permitting and construction. The first major transmission segments associated with this plan are expected to be placed in service during 2010, with other segments placed in service through 2019, depending on siting, permitting and construction schedules.

As part of the March 2006 acquisition of PacifiCorp, MEHC and PacifiCorp made a number of commitments to the state regulatory commissions in all six states in which PacifiCorp has retail customers. These commitments are generally being implemented over several years following the acquisition and are subject to subsequent regulatory review and approval. As of December 31, 2009, the status of the key financial commitments was as follows:

- Invest approximately $812 million in emissions reduction technology for PacifiCorp's existing coal-fired generating facilities. Through December 31, 2009, PacifiCorp had spent a total of $865 million, including non-cash equity AFUDC, on these emissions reduction projects. During 2010, PacifiCorp expects to file notification of its completion of this commitment with the applicable state regulatory commissions.
- Invest in certain transmission and distribution system projects that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization in an amount that was originally estimated to be approximately $520 million at the date of the acquisition. Through December 31, 2009, PacifiCorp had spent a total of $796 million in capital expenditures, including non-cash equity AFUDC, which was in excess of the original estimate due to the evolving nature of the projects agreed to in the commitment. This amount includes costs for the transmission expansion program discussed above.

Transmission

PacifiCorp has agreements for the right to transmit electricity over other entities' transmission lines to facilitate delivery to PacifiCorp's customers.

Operating Leases

PacifiCorp leases offices, certain operating facilities, land and equipment under operating leases that expire at various dates through the year ending December 31, 2092. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property.

Net rent expense was $13 million, $16 million and $24 million during the years ended December 31, 2009, 2008 and 2007, respectively.

Other

PacifiCorp has purchase obligations related to equipment maintenance and various other service and maintenance agreements.

(14) Preferred Stock

PacifiCorp's preferred stock, not subject to mandatory redemption, was as follows as of December 31 (shares in thousands, dollars in millions, except per share amounts):

	Redemption Price Per Share	2009 Shares	2009 Amount	2008 Shares	2008 Amount
Series:					
Serial Preferred, $100 stated value, 3,500 shares authorized					
4.52% to 4.72%	$102.3 to $103.5	157	$ 15	157	$ 15
5.00% to 5.40%	$100.0 to $101.0	108	10	108	10
6.00%	Non-redeemable	6	1	6	1
7.00%	Non-redeemable	18	2	18	2
5% Preferred, $100 stated value, 127 shares authorized	$110.0	126	13	126	13
		415	$ 41	415	$ 41

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. In the event of voluntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all preferred stock is entitled to stated value plus accrued dividends. Dividends on all preferred stock are cumulative. Holders also have the right to elect members to the PacifiCorp board of directors in the event dividends payable are in default in an amount equal to four full quarterly payments.

Dividends declared but not yet due for payment on preferred stock were $1 million as of December 31, 2009 and 2008.

(15) Common Shareholder's Equity

Through PPW Holdings LLC, MEHC is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized MEHC's acquisition of PacifiCorp contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

As of December 31, 2009, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 47.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. This minimum level of common equity declines to 46.25% for the year ending December 31, 2010, 45.25% for the year ending December 31, 2011 and 44% thereafter. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by MEHC as common equity. As of December 31, 2009, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 51%, and PacifiCorp was permitted to dividend $928 million under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or MEHC if PacifiCorp's unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of December 31, 2009, PacifiCorp's unsecured debt rating was A- by Standard & Poor's Rating Services, BBB+ by Fitch Ratings and Baa1 by Moody's Investor Service.

PacifiCorp is also subject to a maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Notes 8 and 9.

(16) Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss, net is included in PacifiCorp shareholders' equity on the Consolidated Balance Sheets and consists of unrecognized amounts on retirement benefits of $6 million, net of tax of $3 million, and $2 million, net of tax of $2 million, as of December 31, 2009 and 2008, respectively.

(17) Variable-Interest Entities

PacifiCorp holds an undivided interest in 50% of the 474-MW Hermiston generating facility (refer to Note 4), procures 100% of the fuel input into the generating facility and subsequently receives 100% of the generated electricity, 50% of which is acquired through a long-term power purchase agreement. As a result, PacifiCorp holds a variable interest in the joint owner of the remaining 50% of the facility and is the primary beneficiary. PacifiCorp has been unable to obtain the information necessary to consolidate the entity because the entity has not agreed to supply the information due to the lack of a contractual obligation to do so. PacifiCorp continues to request from the entity the information necessary to perform the consolidation; however, no information has yet been provided by the entity. Cost of the electricity purchased from the joint owner was $36 million during each of the years ended December 31, 2009, 2008 and 2007. The entity is operated by the equity owners and PacifiCorp has no risk of loss in relation to the entity in the event of a disaster.

(18) Related-Party Transactions

PacifiCorp has an intercompany administrative services agreement with its indirect parent company, MEHC. Services provided by PacifiCorp and charged to affiliates relate primarily to administrative services, financial statement preparation and direct-assigned employees. Receivables associated with these activities were $- million and $1 million as of December 31, 2009 and 2008, respectively. Services provided by affiliates and charged to PacifiCorp relate primarily to the administrative services provided under the intercompany administrative services agreement among MEHC and its affiliates. These expenses totaled $9 million during each of the years ended December 31, 2009, 2008 and 2007. Payables associated with these expenses were $2 million and $1 million as of December 31, 2009 and 2008, respectively.

PacifiCorp engages in various transactions with several of its affiliated companies in the ordinary course of business. Services provided by affiliates in the ordinary course of business and charged to PacifiCorp relate primarily to the transportation of natural gas and relocation services. These expenses totaled $3 million, $6 million and $5 million during the years ended December 31, 2009, 2008 and 2007, respectively. Payables associated with these expenses were $1 million and $2 million as of December 31, 2009 and 2008, respectively.

PacifiCorp has long-term transportation contracts with Burlington Northern Santa Fe, LLC ("BNSF"), a wholly owned subsidiary of Berkshire Hathaway and PacifiCorp's ultimate parent company. Transportation costs under these contracts were $29 million, $32 million and $31 million during the years ended December 31, 2009, 2008 and 2007, respectively. As of December 31, 2009 and 2008, PacifiCorp had $1 million and $2 million of accounts payable to BNSF outstanding under these contracts, including indirect payables related to a jointly owned facility.

PacifiCorp participates in a captive insurance program provided by MEHC Insurance Services Ltd. ("MISL"), a wholly owned subsidiary of MEHC. MISL covers all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's current policies, as well as overhead distribution and transmission line property damage. PacifiCorp has no equity interest in MISL and has no obligation to contribute equity or loan funds to MISL. Premium amounts are established based on a combination of actuarial assessments and market rates to cover loss claims, administrative expenses and appropriate reserves, but as a result of regulatory commitments are capped through December 31, 2010. Certain costs associated with the program are prepaid and amortized over the policy coverage period expiring March 20, 2010. Premium expenses were $7 million during each of the years ended December 31, 2009, 2008 and 2007. Prepayments to MISL were $2 million as of December 31, 2009 and 2008. Receivables for claims were $10 million and $7 million as of December 31, 2009 and 2008, respectively.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. As of December 31, 2009 and 2008, income taxes receivable from MEHC were $249 million and $43 million, respectively.

(19) Supplemental Cash Flows Information

The summary of supplemental cash flows information is as follows for the years ended December 31 (in millions):

	2009	2008	2007
Interest paid, net of amounts capitalized	$ 325	$ 280	$ 251
Income taxes (received) paid, net	$ (252)	$ (53)	$ 151
Supplemental disclosure of non-cash investing and financing activities:			
Property, plant and equipment additions in accounts payable	$ 251	$ 405	$ 107
Property, plant and equipment acquired under capital lease obligations	$ -	$ 17	$ -

(20) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2009	June 30, 2009	September 30, 2009	December 31, 2009
Operating revenue	$ 1,116	$ 1,016	$ 1,146	$ 1,179
Operating income	259	228	293	280
Net income	126	110	166	148
Net income attributable to PacifiCorp	123	110	162	147

	Three-Month Periods Ended			
	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
Operating revenue	$ 1,095	$ 1,055	$ 1,245	$ 1,103
Operating income	229	213	276	236
Net income	107	96	139	123
Net income attributable to PacifiCorp	108	99	132	119

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A(T). Controls and Procedures

Disclosure Controls and Procedures

At the end of the period covered by this Annual Report on Form 10-K, PacifiCorp carried out an evaluation, under the supervision and with the participation of PacifiCorp's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), of the effectiveness of the design and operation of PacifiCorp's disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon that evaluation, PacifiCorp's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), concluded that PacifiCorp's disclosure controls and procedures were effective to ensure that information required to be disclosed by PacifiCorp in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and is accumulated and communicated to management, including PacifiCorp's Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer), or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. There has been no change in PacifiCorp's internal control over financial reporting during the quarter ended December 31, 2009 that has materially affected, or is reasonably likely to materially affect, PacifiCorp's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of PacifiCorp is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Securities Exchange Act of 1934 Rule 13a-15(f). Under the supervision and with the participation of PacifiCorp's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), PacifiCorp's management conducted an evaluation of the effectiveness of PacifiCorp's internal control over financial reporting as of December 31, 2009 as required by the Securities Exchange Act of 1934 Rule 13a-15(c). In making this assessment, PacifiCorp's management used the criteria set forth in the framework in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the evaluation conducted under the framework in "Internal Control – Integrated Framework," PacifiCorp's management concluded that PacifiCorp's internal control over financial reporting was effective as of December 31, 2009.

This report does not include an attestation report of PacifiCorp's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by PacifiCorp's registered public accounting firm pursuant to temporary rules of the SEC that permit PacifiCorp to provide only management's report in this Annual Report on Form 10-K.

PacifiCorp
March 1, 2010

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

There are no family relationships among the executive officers, nor any arrangements or understandings between any executive officer and any other person pursuant to which the executive officer was appointed. Set forth below is certain information, as of January 31, 2010, with respect to each of the current directors and executive officers of PacifiCorp:

Gregory E. Abel, 47, Chairman of the Board of Directors and Chief Executive Officer. Mr. Abel was elected Chief Executive Officer and Chairman of the Board of Directors in March 2006. Mr. Abel is also the President and Chief Executive Officer and a director of MEHC. Mr. Abel joined MEHC in 1992.

Douglas L. Anderson, 51, Director. Mr. Anderson has been a director since March 2006. Mr. Anderson is the Senior Vice President, General Counsel and Corporate Secretary of MEHC. Mr. Anderson joined MEHC in 1993.

Micheal G. Dunn, 44, was elected President of PacifiCorp Energy and director of PacifiCorp effective February 1, 2010. Mr. Dunn had previously served as President of Kern River Gas Transmission Company ("Kern River") since June 2007. Prior to that, Mr. Dunn served as Vice President of Operations, Information Technology and Engineering at Kern River since March 2005. Kern River is an indirect subsidiary of MEHC.

Brent E. Gale, 58, Director. Mr. Gale has been a director since March 2006. Mr. Gale was appointed Senior Vice President of Regulation and Legislation of MEHC in March 2006. Mr. Gale had previously been Senior Vice President of MidAmerican Energy Company, a MEHC subsidiary, since July 2004. Mr. Gale has served in various legal, regulatory legislative and strategic positions with MEHC and its predecessors since 1976.

Patrick J. Goodman, 43, Director. Mr. Goodman has been a director since March 2006. Mr. Goodman was appointed Senior Vice President and Chief Financial Officer of MEHC in 1999. Mr. Goodman joined MEHC in 1995.

Natalie L. Hocken, 40, Director. Ms. Hocken has been a director since August 2007. Ms. Hocken has served as Vice President and General Counsel of Pacific Power, a division of PacifiCorp, since January 2007. Ms. Hocken previously served as Assistant General Counsel and Senior Counsel for PacifiCorp. Ms. Hocken joined PacifiCorp in 2002.

Mark C. Moench, 54, Senior Vice President and General Counsel and Director. Mr. Moench was named PacifiCorp Senior Vice President and General Counsel in February 2007. Mr. Moench joined PacifiCorp as Senior Vice President and General Counsel of Rocky Mountain Power, a division of PacifiCorp, and was elected director in March 2006. Mr. Moench previously served as Senior Vice President, Law, of MEHC with responsibility for regulatory approvals of the PacifiCorp acquisition since June 2005. Prior to that, Mr. Moench was Vice President and General Counsel of Kern River since 2002.

R. Patrick Reiten, 48, President, Pacific Power and Director. Mr. Reiten was elected President of Pacific Power and director in September 2006. Mr. Reiten previously served as President and Chief Executive Officer of PNGC Power since 2002. Mr. Reiten joined PNGC Power in 1993 serving as Director of Government Relations, then as Vice President of Marketing and Public Affairs.

Douglas K. Stuver, 46, Senior Vice President and Chief Financial Officer. Mr. Stuver was elected Senior Vice President and Chief Financial Officer of PacifiCorp effective March 1, 2008. Mr. Stuver joined PacifiCorp in March 2004 as Managing Director and Division Controller of PacifiCorp's commercial and trading business unit. In March 2006, Mr. Stuver was appointed Managing Director and Division Controller of PacifiCorp Energy, a division of PacifiCorp. Prior to joining PacifiCorp, Mr. Stuver served as Vice President of Corporate Risk Management at Duke Energy Corporation.

A. Richard Walje, 58, President, Rocky Mountain Power and Director. Mr. Walje was elected President of Rocky Mountain Power in March 2006. Mr. Walje has been a director since July 2001. Mr. Walje previously served as PacifiCorp's Executive Vice President since April 2004 and as Chief Information Officer since May 2000. Mr. Walje also served as Senior Vice President of Corporate Business Services from May 2001 to April 2004 and as Vice President for Transmission and Distribution Operations and Customer Service from 1998 to 2000. Mr. Walje has been with PacifiCorp since 1986.

Board's Role in the Risk Oversight Process

PacifiCorp's Board of Directors is comprised of a combination of MEHC senior executives and PacifiCorp senior management who have direct and indirect responsibility for the management and oversight of risk in their respective areas of responsibility. The PacifiCorp Board of Directors has not established a separate risk management and oversight committee.

Audit Committee and Audit Committee Financial Expert

During the year ended December 31, 2009, and as of the date of this Annual Report on Form 10-K, PacifiCorp's Board of Directors did not have an audit committee. Because PacifiCorp's common stock is indirectly, wholly owned by MEHC, its Board of Directors consists primarily of MEHC and PacifiCorp employees and it is not required to have an audit committee. However, the audit committee of MEHC acts as the audit committee for PacifiCorp.

Code of Ethics

PacifiCorp has adopted a code of ethics that applies to its principal executive officer, its principal financial and accounting officer, or persons acting in such capacities, and certain other covered officers. The code of ethics is incorporated by reference in the exhibits to this Annual Report on Form 10-K.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Compensation Philosophy and Overall Objectives

We and our indirect parent company, MidAmerican Energy Holdings Company, or MEHC, believe that the compensation paid to each of our Chief Executive Officer, or CEO, our Chief Financial Officer, or CFO, and our three other most highly compensated executive officers, to whom we refer collectively as our Named Executive Officers, or NEOs, should be closely aligned with our overall performance, and each NEO's contribution to that performance, on both a short- and long-term basis, and that such compensation should be sufficient to attract and retain highly qualified leaders who can create significant value for our organization. Our compensation programs are designed to provide our NEOs meaningful incentives for superior corporate and individual performance. Performance is evaluated on a subjective basis within the context of both financial and non-financial objectives that we believe contribute to our long-term success, among which are customer service, operational excellence, financial strength, employee commitment and safety, environmental respect and regulatory integrity.

How is Compensation Determined

Our compensation committee consists solely of the Chairman of our Board of Directors, Mr. Gregory E. Abel. Mr. Abel also serves as our CEO and as MEHC's President and Chief Executive Officer. Mr. Abel is employed by MEHC and receives no direct compensation from us. Mr. Abel is responsible for the establishment and oversight of our compensation policy for our NEOs and for approving base pay increases, incentive and performance awards, off-cycle pay changes, and participation in other employee benefit plans and programs.

Our criteria for assessing executive performance and determining compensation in any year is inherently subjective and is not based upon specific formulas or weighting of factors. Given the uniqueness of each NEO's duties, we do not specifically use other companies as benchmarks when establishing our NEOs' compensation.

Discussion and Analysis of Specific Compensation Elements

Base Salary

We determine base salaries for all of our NEOs, other than Mr. Abel, by reviewing our overall performance and each NEO's performance, the value each NEO brings to us and general labor market conditions. While base salary provides a base level of compensation intended to be competitive with the external market, the annual base salary adjustment for each NEO, other than Mr. Abel, is determined on a subjective basis after consideration of these factors and is not based on target percentiles or other formal criteria. All merit increases are approved by Mr. Abel and take effect in the last payroll period of each year. An increase or decrease in base salary may also result from a promotion or other significant change in a NEO's responsibility during the year. In 2009, base salaries for all NEOs, other than Mr. Abel, increased on average by 2.9% and became effective December 26, 2008. There have been no base salary changes for our NEOs since the December 26, 2008 merit increase.

Short-Term Incentive Compensation

The objective of short-term incentive compensation is to reward the achievement of significant annual corporate and business unit goals while also providing NEOs with competitive total cash compensation.

Annual Incentive Plan

Under our Annual Incentive Plan, or AIP, all NEOs, other than Mr. Abel, are eligible to earn an annual discretionary cash incentive award, which is determined by Mr. Abel and is not based on a specific formula or cap. Mr. Abel establishes a target bonus opportunity, expressed as a percentage of base salary and intended to reflect fully effective performance, for each of the other NEOs prior to the beginning of each year. Awards paid to a NEO under the AIP are based on a variety of measures linked to each NEO's performance, our overall performance and each NEO's contribution to that overall performance. An individual NEO's performance is measured against defined objectives that commonly include financial and non-financial measures (e.g., customer service, operational excellence, financial strength, employee commitment and safety, environmental respect and regulatory integrity), as well as the NEO's response to issues and opportunities that arise during the year. Approved awards are paid prior to year-end.

Performance Awards

In addition to the annual awards under the AIP, we may grant cash performance awards periodically during the year to one or more NEOs, other than Mr. Abel, to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and approved by Mr. Abel. In January 2009, Mr. Stuver received a performance award of $20,000 in recognition of efforts to support our objectives.

Long-Term Incentive Compensation

The objective of long-term incentive compensation is to retain NEOs, reward their exceptional performance and motivate them to create long-term, sustainable value. Our current long-term incentive compensation program is cash-based. We do not utilize stock option awards or other forms of equity-based awards.

Long-Term Incentive Partnership Plan

The MEHC Long-Term Incentive Partnership Plan, or LTIP, is designed to retain key employees and to align our interests and the interests of the participating employees. All of our NEOs, other than Mr. Abel, participate in the LTIP. The LTIP provides for annual discretionary awards based upon significant accomplishments by the individual participants and the achievement of the financial and non-financial objectives previously described. The goals are developed with the objective of being attainable with a sustained, focused and concerted effort and are determined and communicated in January of each plan year. Participation is discretionary and is determined by both the Chairman of the Board of Directors and the Chief Executive Officer of MEHC who recommend awards to the MEHC compensation committee annually in the fourth quarter. Except for limited situations of extraordinary performance, awards are capped at 1.5 times base salary and finalized in the first quarter of the following year. These cash-based awards are subject to mandatory deferral and equal annual vesting over a five-year period starting in the performance year. In 2009, participants allocated the value of their deferral accounts among various investment alternatives, which were determined by a vote of all participants. Beginning in 2010, the investment allocation for each participant's deferral accounts has been determined by each participant rather than by the vote of all participants. Gains or losses may be incurred based on the investment performance. Participating NEOs may elect to defer all or a part of the award or receive payment in cash after the five-year mandatory deferral and vesting period. Vested balances (including any investment profits or losses thereon) of terminating participants are paid at the time of termination.

Other Employee Benefits

Supplemental Executive Retirement Plan

Our Supplemental Executive Retirement Plan, or SERP, provides additional retirement benefits to participants. Mr. Walje was the only NEO who participated in our SERP during 2009, and we have no plans to add new participants in the future. The SERP provides monthly retirement benefits of 50% of final average pay plus 1% of final average pay for each fiscal year that we meet certain performance goals set for such fiscal year. The maximum benefit is 65% of final average pay. A participant's final average pay equals the 60 consecutive months of highest pay out of the last 120 months, and pay for this purpose includes salary and annual incentive plan payments reflected in the Summary Compensation Table below.

Deferred Compensation Plan

Our Executive Voluntary Deferred Compensation Plan, or DCP, provides a means for all NEOs, other than Mr. Abel, to make voluntary deferrals of up to 50% of base salary and 100% of short-term incentive compensation awards. We include the DCP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package. The deferrals and any investment returns grow on a tax-deferred basis. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of eight investment options offered under the DCP and selected by the participant. The plan allows participants to choose from three forms of distribution. The plan permits us to make discretionary contributions on behalf of participants.

Potential Payments Upon Termination or Change-in-Control

Our NEOs (excluding Mr. Abel) are not entitled to severance or enhanced benefits upon termination of employment or change-in-control. Please refer to MEHC's Annual Report on Form 10-K for the year ended December 31, 2009 (File No. 001-14881) for information about potential post-termination and change-in-control payments to Mr. Abel. However, upon any termination of employment, our other NEOs would be entitled to the vested balances in the Retirement Plan, SERP, LTIP and the DCP.

Compensation Committee Report

Mr. Abel, our Chairman and Chief Executive Officer and sole member of our compensation committee, has reviewed and discussed the Compensation Discussion and Analysis with management and, based on this review and discussion, has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Summary Compensation Table

The following table sets forth information regarding compensation earned by each of our NEOs during the years indicated:

Name and Principal Position	Year	Base Salary	Bonus [1]	Change in Pension Value and Nonqualified Deferred Compensation Earnings [2]	All Other Compensation [3]	Total
Gregory E. Abel [4]	2009	$ -	$ -	$ -	$ -	$ -
Chairman and	2008	-	-	-	-	-
Chief Executive Officer	2007	-	-	-	-	-
A. Richard Walje	2009	351,900	583,217	733,231	54,617	1,722,965
President, Rocky Mountain	2008	345,000	328,769	267,902	10,283	951,954
Power	2007	335,811	346,582	177,128	486,302	1,345,823
R. Patrick Reiten	2009	265,740	623,417	355	35,892	925,404
President, Pacific Power	2008	258,000	353,472	11,548	24,462	647,482
	2007	250,000	330,838	3,484	2,083	586,405
A. Robert Lasich [6]	2009	236,000	425,368	28,556	20,237	710,161
President, PacifiCorp Energy	2008	230,000	234,948	32,175	9,231	506,354
	2007	173,580	257,603	11,311	9,181	451,675
Douglas K. Stuver	2009	228,800	231,033	12,623	39,945	512,401
Senior Vice President and	2008	215,499	133,140	28,928	8,817	386,384
Chief Financial Officer	2007	-	-	-	-	-

(1) Consists of annual cash incentive awards earned pursuant to the AIP for our NEOs, performance award of $20,000 to Mr. Stuver, the vesting of LTIP awards and associated vested earnings for Messrs. Walje, Reiten, Lasich and Stuver. The breakout of AIP and LTIP awards for 2009 is as follows:

			LTIP		
	AIP	Performance Award	Vested Award	Vested Earnings	Change in Value [(a)]
A. Richard Walje	$ 180,000	$ -	$ 290,577	$ 112,640	$ 403,217
R. Patrick Reiten	215,000	-	295,717	112,700	408,417
A. Robert Lasich	162,250	-	177,836	85,282	263,118
Douglas K. Stuver	85,000	20,000	90,915	35,118	126,033

(a) Represents vested award plus vested earnings.

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid may increase or decrease depending on investment performance. Net income, the net income target goal and the matrix below were used in determining the gross amount of the LTIP award available to the participants. Net income for determining the award and the award are subject to discretionary adjustment by both the Chairman of the Board of Directors, the Chief Executive Officer and the compensation committee of MEHC. In 2009, the gross award and per-point value were determined based on the overall achievement of our financial and non-financial objectives.

MEHC Net Income	Award
Less than or equal to net income target goal	None
Exceeds net income target goal by 0.01% – 3.25%	15% of excess
Exceeds net income target goal by 3.251% – 6.50%	15% of the first 3.25% excess; 25% of excess over 3.25%
Exceeds net income target goal by more than 6.50%	15% of the first 3.25% excess; 25% of the next 3.25% excess; 35% of excess over 6.50%

Points are allocated among plan participants either as initial points or year-end performance points. A nominating committee recommends the point allocation, subject to approval by both the Chairman of the Board of Directors and the Chief Executive Officer of MEHC, based upon a discretionary evaluation of individual achievement of financial and non-financial goals previously described herein. A participant's award equals the participant's allocated points multiplied by the final per-point value, capped at 1.5 times base salary except in extraordinary circumstances.

(2) Amounts are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which include the SERP and the Retirement Plan, as applicable. Amounts are computed using assumptions consistent with those used in preparing the related pension disclosures in our Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and are as of the pension plans' measurement dates. No participant in our DCP earned "above market" or "preferential" earnings on amounts deferred.

(3) Includes contributions to our Employee Savings Plan ("401(k) Plan") of $34,800 for Mr. Walje, $35,892 for Mr. Reiten, $11,855 for Mr. Lasich and $34,655 for Mr. Stuver. Also includes a one-time buyback of unused personal time in the amounts of $13,534 for Mr. Walje and $7,770 for Mr. Lasich.

(4) Mr. Abel receives no direct compensation from us. We reimburse MEHC for the cost of Mr. Abel's time spent on matters supporting us, including compensation paid to him by MEHC, pursuant to an intercompany administrative services agreement among MEHC and its subsidiaries. Please refer to MEHC's Annual Report on Form 10-K for the year ended December 31, 2009 (File No. 001-14881) for executive compensation information for Mr. Abel.

(5) On January 13, 2010, Mr. Lasich accepted the position of Vice President and General Counsel, Procurement for MEHC and accordingly resigned as President of PacifiCorp Energy and as our director effective February 1, 2010.

Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of our NEOs as of December 31, 2009:

Name	Plan Name	Number of Years of Credited Service	Present Value of Accumulated Benefit
Gregory E. Abel	N/A	-	$ -
A. Richard Walje	Retirement	22.83	781,135
	SERP	23.83	2,210,537
R. Patrick Reiten	Retirement	2.25	15,387
A. Robert Lasich	Retirement	3.75	75,980
Douglas K. Stuver	Retirement	4.75	77,740

We have adopted a non-contributory defined benefit pension plan, or the Retirement Plan, for the majority of our employees, other than employees subject to collective bargaining agreements that do not provide for coverage. Mr. Walje also participates in our nonqualified SERP. Through May 31, 2007, participants earned benefits at retirement payable for life based on length of service through May 31, 2007 and average pay in the 60 consecutive months of highest pay out of the 120 months prior to May 31, 2007, and pay for this purpose included salary and annual incentive plan payments up to 10% of base salary, but were limited to the Internal Revenue Code amounts specified in §401(a)(17). Benefits were based on 1.3% of final average pay plus 0.65% of final average pay in excess of covered compensation (as defined in Internal Revenue Code §401(1)(5)(E)) times years of service.

The Retirement Plan was restated effective June 1, 2007 to change from a traditional final-average-pay formula as described above to a cash balance formula for non-union participants. Benefits under the final-average-pay formula were frozen as of May 31, 2007, and no future benefits will accrue under that formula for non-union participants. Under the cash balance formula, benefits are based on 6.5% (5.0% for employees hired after June 30, 2006 and before January 1, 2008) of eligible compensation plus 4.0% of eligible compensation in excess of compensation subject to Federal Insurance Contributions Act withholding ($106,800 for 2009) to each participant's account (where such salary and incentive amounts are reduced for Internal Revenue Code §401(a)(17) limits). However, the 4.0% portion of the formula was eliminated on August 1, 2009 and therefore for 2009 benefits were based on eligible compensation for the first seven months that exceeded $62,300 (7/12th of $106,800). Interest is also credited to each participant's account. Employees who were age 40 or older as of May 31, 2007 receive certain additional transition pay credits for five years from the effective date of the plan restatement. Effective January 1, 2009, non-union participants were offered the option to continue to receive pay credits in the Retirement Plan as of December 31, 2008 or receive equivalent fixed 401(k) contributions.

Participants are entitled to receive full benefits upon retirement after age 65. Participants are also entitled to receive reduced benefits upon early retirement after age 55 with at least five years of service or when age plus years of service equals 75.

Amounts are computed using assumptions consistent with those used in preparing the related pension disclosures in our Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and are as of December 31, 2009, which is the measurement date for the plans. Single life annuities were assumed for the SERP calculations of the present value of accumulated benefits. For the Retirement Plan calculations of the present value of accumulated benefits, the following assumptions were used: 50.0% lump sum and 50.0% single life annuity. The present value assumptions used in calculating the present value of accumulated benefits for the SERP were as follows: a discount rate of 5.80%; an expected retirement age of 60; and postretirement mortality using the RP-2000 tables. The present value assumptions used in calculating the present value of accumulated benefits for the Retirement Plan were as follows: a discount rate of 5.80%; an expected retirement age of 65; postretirement mortality using the RP-2000 tables projected to 2010; a lump sum interest rate of 5.55%; and lump sum mortality using the Internal Revenue Code §417(e)(3) Applicable Mortality Table for 2010.

In 2008, non-union employee participants in the Retirement Plan were offered the option to continue to receive pay credits in the Retirement Plan or receive equivalent fixed contributions to the 401(k) plan, with any such election becoming effective January 1, 2009. Messrs. Walje, Reiten and Stuver elected the equivalent fixed 401(k) contribution option and, therefore, will no longer receive pay credits in the Retirement Plan; however, they each will continue to receive interest credits.

The SERP provides monthly retirement benefits of 50% of final average pay plus 1% of final average pay for each fiscal year that we meet certain performance goals set for such fiscal year. The maximum benefit is 65% of final average pay. A participant's final average pay equals the 60 consecutive months of highest pay out of the last 120 months, and pay for this purpose includes salary and annual incentive plan payments reflected in the Summary Compensation Table above. Mr. Walje has met the five-year participation requirement under the plan for early retirement eligibility. Mr. Walje's SERP benefit will be reduced by a portion of his Social Security benefits, his regular retirement benefit under the Retirement Plan, and 0.25% for each month benefit commencement precedes age 60.

The above reference for the number of years of service and the present value of accumulated benefits for Mr. Lasich represents his service as a PacifiCorp employee only and does not include any vested benefits earned under MidAmerican Energy Company.

Nonqualified Deferred Compensation

The following table sets forth certain information regarding the DCP accounts held by each of our NEOs as of December 31, 2009:

Name	Executive Contributions in 2009	Registrant Contributions(1) in 2009	Aggregate Earnings in 2009	Aggregate Balance (2) as of December 31, 2009
Gregory E. Abel	$ -	$ -	$ -	$ -
A. Richard Walje	-	5,959	10,944	1,799,112
R. Patrick Reiten	-	-	-	-
A. Robert Lasich	-	-	15,775	134,147
Douglas K. Stuver	-	5,290	-	5,290

(1) The contribution amounts shown for Mr. Walje and Mr. Stuver are included for 2009 in the "All Other Compensation" column in the Summary Compensation Table and are not additional earned compensation.

(2) In addition to the 2009 registrant contributions, the aggregate balance at period-end for Mr. Lasich includes executive contribution amounts of $65,000 and $85,000 for 2008 and 2007, respectively, in the "Bonus" column and for Mr. Walje includes executive contribution amounts of $69,000 for 2008 in the "Salary" column and $120,000 for 2008 in the "Bonus" column of the Summary Compensation Table.

Eligibility for our DCP is restricted to select management and highly compensated employees. The plan provides tax benefits to eligible participants by allowing them to defer compensation on a pretax basis, thus reducing their current taxable income. Deferrals and any investment returns grow on a tax-deferred basis, thus participants pay no income tax until they receive distributions. The DCP permits participants to make a voluntary deferral of up to 50% of base salary and 100% of short-term incentive compensation awards. All deferrals are net of social security taxes. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of eight investment options offered by the plan and selected by the participant. Gains or losses are calculated daily, and returns are posted to accounts based on participants' fund allocation elections. Participants can change their fund allocations as of the end of any day on which the market is open.

The DCP allows participants to maintain three accounts based upon when they want to receive payments: retirement account, in-service account and education account. Both the retirement and in-service accounts can be distributed as lump sums or in up to 10 annual installments, except in the case of the four DCP transition accounts that allow for a grandfathered payout based on the previous deferred compensation plan distribution elections of lump sum, 5, 10 or 15 annual installments. Effective December 31, 2006, no new money may be deferred into the DCP transition accounts. The education account is distributed in four annual installments. If a participant leaves employment prior to retirement (age 55), all amounts in the participant's account will be paid out in a lump sum as soon as administratively practicable. Participants are 100% vested in their deferrals and any investment gains or losses recorded in their accounts.

Participants in our LTIP also have the option of deferring all or a part of those awards after the five-year mandatory deferral and vesting period. The provisions governing the deferral of LTIP awards are similar to those described for the DCP above.

Potential Payments Upon Termination or Change-in-Control

Our NEOs (excluding Mr. Abel) are not entitled to severance or enhanced benefits upon termination of employment or change-in-control. Please refer to MEHC's Annual Report on Form 10-K for the year ended December 31, 2009 (File No. 001-14881) for information about potential post-termination change-in-control payments to Mr. Abel.

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2009, and are payable as lump sums unless otherwise noted.

Termination Scenario	Incentive (1)	Pension (2)
Gregory E. Abel:		
Retirement, Voluntary and Involuntary With or Without Cause	$ -	$ -
Death and Disability	-	-
A. Richard Walje (3):		
Retirement, Voluntary and Involuntary With or Without Cause	-	364,894
Death and Disability	723,144	364,894
R. Patrick Reiten:		
Retirement, Voluntary and Involuntary With or Without Cause	-	3,276
Death and Disability	778,934	3,276
A. Robert Lasich:		
Retirement, Voluntary and Involuntary With or Without Cause	-	12,326
Death and Disability	355,952	12,326
Douglas K. Stuver:		
Retirement, Voluntary and Involuntary With or Without Cause	-	10,040
Death and Disability	267,841	10,040

(1) Amounts represent the unvested portion of each NEOs LTIP account, which becomes 100% vested upon death or disability.

(2) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits table.

(3) Mr. Walje has already met the retirement criteria, therefore his termination and death scenarios under the Retirement Plan are based on assuming 50% lump sum payout and 50% annuity.

Director Compensation Table

All of our directors serving in 2009 were employees of PacifiCorp, or in the case of Messrs. Anderson and Goodman, employees of MEHC, and did not receive additional compensation for service as a director. The following table excludes Messrs. Abel, Walje, Reiten and Lasich, for whom compensation information is described in the Summary Compensation Table.

Name	Change in Pension Value and Nonqualified Deferred Compensation Earnings (1)	All Other Compensation (2)	Total
Douglas L. Anderson	$ -	$ -	$ -
Brent E. Gale	33,949	936,375	970,324
Patrick J. Goodman	-	-	-
Natalie L. Hocken	11,466	495,489	506,955
Mark C. Moench	32,110	638,571	670,681

(1) Amounts included in change in pension value and nonqualified deferred compensation earnings are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which include the SERP and the Retirement Plan, as applicable. Amounts are computed using assumptions consistent with those used in preparing the applicable pension disclosures included in our Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K and are as of the pension plans' measurement dates. No participant in our DCP earned "above market" or "preferential" earnings on amounts deferred.

(2) Amounts shown for the year ended December 31, 2009, include:

(i) Base salary in the amounts of $287,000 for Mr. Gale, $184,881 for Ms. Hocken and $218,754 for Mr. Moench.

(ii) Performance award of $25,000 to Mr. Gale in recognition of efforts to support our objectives and $5,000, including gross-up of $2,294 to Mr. Moench for efforts on PacifiCorp regulatory and legislative matters.

(iii) Contributions to our 401(k) Plan of $5,485 for Mr. Gale, $33,731 for Ms. Hocken and $11,679 for Mr. Moench.

(iv) One-time buyback of unused personal time in the amounts of $11,039 for Mr. Gale, $6,125 for Ms. Hocken and $8,413 for Mr. Moench.

(v) Life insurance premium paid by us on behalf of Mr. Gale in the amount of $12,850.

(vi) Annual cash incentive awards earned pursuant to the AIP for our directors, the vesting of LTIP awards and associated vested earnings for Mr. Gale, Ms. Hocken and Mr. Moench. The breakout of AIP and LTIP awards for 2009 is as follows:

		LTIP		
	AIP	Vested Award	Vested Earnings	Change in Value (a)
Brent E. Gale	$ 140,000	$ 304,058	$ 150,943	$ 455,001
Natalie L. Hocken	135,000	103,135	32,617	135,752
Mark C. Moench	92,970	202,111	97,350	299,461

(a) Represents vested award plus vested earnings.

Compensation Committee Interlocks and Insider Participation

Mr. Abel is our Chairman of the Board of Directors and CEO and also the President and Chief Executive Officer of MEHC. None of our executive officers serve as a member of the compensation committee of any company that has an executive officer serving as a member of our Board of Directors. None of our executive officers serve as a member of the board of directors of any company (other than MEHC) that has an executive officer serving as a member of our compensation committee. See also Item 13 of this Annual Report on Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

All outstanding shares of our common stock are indirectly owned by MEHC, 666 Grand Avenue, Des Moines, Iowa 50309. MEHC is a consolidated subsidiary of Berkshire Hathaway that, as of January 31, 2010, owns 89.5% of MEHC's common stock. The balance of MEHC's common stock is owned by Walter Scott, Jr. (along with family members and related entities), a member of MEHC's Board of Directors, and Gregory E. Abel, PacifiCorp's Chairman and Chief Executive Officer.

None of our executive officers or directors owns shares of our preferred stock. The following table sets forth certain information as of January 31, 2010 regarding the beneficial ownership of common stock of MEHC and the Class A and Class B common stock of Berkshire Hathaway held by each of our directors, executive officers and all of our directors and executive officers as a group as of January 31, 2010.

	MEHC Common Stock		Berkshire Hathaway Class A Common Stock		Berkshire Hathaway Class B Common Stock	
Beneficial Owner	**Number of Shares Beneficially Owned [(1)]**	**Percentage of Class [(1)]**	**Number of Shares Beneficially Owned [(1)]**	**Percentage of Class [(1)]**	**Number of Shares Beneficially Owned [(1)]**	**Percentage of Class [(1)]**
Gregory E. Abel [(2)]	595,940	0.8%	1	*	1,600	*
Douglas L. Anderson	-	-	4	*	200	*
Micheal G. Dunn	-	-	-	-	-	-
Brent E. Gale	-	-	-	-	-	-
Patrick J. Goodman	-	-	2	*	650	*
Natalie L. Hocken	-	-	-	-	-	-
A. Robert Lasich [(3)]	-	-	-	-	-	-
Mark C. Moench	-	-	2	*	-	-
R. Patrick Reiten	-	-	-	-	-	-
Douglas K. Stuver	-	-	-	-	-	-
A. Richard Walje	-	-	-	-	-	-
All executive officers and directors as a group (11 persons)	595,940	0.8%	9	*	2,450	*

* Indicates beneficial ownership of less than one percent of all outstanding shares.

(1) Includes shares of which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.

(2) In accordance with a shareholders' agreement, as amended on December 7, 2005, based on an assumed value for MEHC's common stock and the closing price of Berkshire Hathaway common stock on January 31, 2010, Mr. Abel would be entitled to exchange his shares of MEHC common stock for 1,170 shares of Berkshire Hathaway Class A stock or 1,754,370 shares of Berkshire Hathaway Class B stock. Assuming an exchange of all available MEHC shares into either Berkshire Hathaway Class A stock or Berkshire Hathaway Class B stock, Mr. Abel would beneficially own less than 1% of the outstanding shares of either class of stock.

(3) On January 13, 2010, Mr. Lasich accepted the position of Vice President and General Counsel, Procurement for MEHC and accordingly resigned as President of PacifiCorp Energy and as our director effective February 1, 2010.

Other Matters

Pursuant to a shareholders' agreement, as amended on December 7, 2005, Mr. Abel is able to require Berkshire Hathaway to exchange any or all of his shares of MEHC common stock for shares of Berkshire Hathaway common stock. The number of shares of Berkshire Hathaway common stock to be exchanged is based on the fair market value of MEHC common stock divided by the closing price of the Berkshire Hathaway common stock on the day prior to the date of exchange.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Review, Approval or Ratification of Transactions with Related Persons

The Berkshire Hathaway Code of Business Conduct and Ethics and the MEHC Code of Business Conduct, or the Codes, which apply to all of our directors, officers and employees and those of our subsidiaries, generally govern the review, approval or ratification of any related-person transaction. A related-person transaction is one in which we or any of our subsidiaries participate and in which one or more of our directors, executive officers, holders of more than five percent of our voting securities or any of such persons' immediate family members have a direct or indirect material interest.

Under the Codes, all of our directors and executive officers (including those of our subsidiaries) must disclose to our legal department any material transaction or relationship that reasonably could be expected to give rise to a conflict with our interests. No action may be taken with respect to such transaction or relationship until approved by the legal department. For our chief executive officer and chief financial officer, prior approval for any such transaction or relationship must be given by Berkshire Hathaway's audit committee. In addition, prior legal department approval must be obtained before a director or executive officer can accept employment, offices or board positions in other for-profit businesses, or engage in his or her own business that raises a potential conflict or appearance of conflict with our interests.

Under an intercompany administrative services agreement we have entered into with MEHC and its other subsidiaries, the cost of certain administrative services provided by MEHC to us or by us to MEHC, or shared with MEHC and other subsidiaries, are directly charged or allocated to the entity receiving such services. This agreement has been filed with the utility regulatory commissions in the states where we serve retail customers. We also provide an annual report of all transactions with our affiliates to our state regulatory commissions, who have the authority to refuse recovery in retail rates for payments we make to our affiliates deemed to have the effect of subsidizing the separate business activities of MEHC or its other subsidiaries.

Refer to Note 18 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding related-party transactions.

Director Independence

Because our common stock is indirectly, wholly owned by MEHC, our Board of Directors consists primarily of MEHC and PacifiCorp employees and we are not required to have independent directors or audit, nominating or compensation committees consisting of independent directors.

Based on the standards of the New York Stock Exchange, Inc., on which the common stock of our ultimate parent company, Berkshire Hathaway, is listed, our Board of Directors has determined that none of our directors are considered independent because of their employment by MEHC or PacifiCorp.

Item 14. Principal Accountant Fees and Services

Fees and Pre-Approval Policy

The following table shows PacifiCorp's fees paid or accrued for audit and audit-related services and fees paid for tax and all other services rendered by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, the "Deloitte Entities") for each of the last two years (in millions):

	2009	2008
Audit fees (1)	$ 1.8	$ 2.1
Audit-related fees (2)	0.2	0.3
Tax fees (3)	-	-
All other fees	-	-
Total aggregate fees billed	$ 2.0	$ 2.4

(1) Audit fees include fees for the audit of PacifiCorp's consolidated financial statements and interim reviews of PacifiCorp's quarterly financial statements, audit services provided in connection with required statutory audits, and comfort letters, consents and other services related to SEC matters.

(2) Audit-related fees primarily include fees for assurance and related services for any other statutory or regulatory requirements, audits of certain employee benefit plans and consultations on various accounting and reporting matters.

(3) Tax fees include fees for services relating to tax compliance, tax planning and tax advice. These services include assistance regarding federal and state tax compliance, tax return preparation and tax audits.

The audit committee of MEHC reviewed and approved the services rendered by the Deloitte Entities in and for fiscal 2009 as set forth in the above table and concluded that the non-audit services were compatible with maintaining the principal accountant's independence. Under the Sarbanes-Oxley Act of 2002, all audit and non-audit services performed by the principal accountant require approval in advance by the audit committee in order to assure that such services do not impair the principal accountant's independence from PacifiCorp. Accordingly, the audit committee has an Audit and Non-Audit Services Pre-Approval Policy (the "Policy") that sets forth the procedures and the conditions pursuant to which services to be performed by the principal accountant are to be pre-approved. Pursuant to the Policy, certain services described in detail in the Policy may be pre-approved on an annual basis together with pre-approved maximum fee levels for such services. The services eligible for annual pre-approval consist of services that would be included under the categories of audit fees, audit-related fees and tax fees. If not pre-approved on an annual basis, proposed services must otherwise be separately approved prior to being performed by the principal accountant. In addition, any services that receive annual pre-approval but exceed the pre-approved maximum fee level also will require separate approval by the audit committee prior to being performed. The Policy does not delegate to management the audit committee's responsibilities to pre-approve services performed by the principal accountant.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

(i) Financial Statements:
Financial statements are included in Item 8.

(ii) Financial Statement Schedules:
All schedules have been omitted because they are either not applicable, not required or the information required to be set forth therein is included on the Consolidated Financial Statements or notes thereto.

(b) Exhibits

The exhibits listed on the accompanying Exhibit Index are filed as part of this Annual Report.

(c) Financial statements required by Regulation S-X, which are excluded from the Annual Report by Rule 14a-3(b).

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 1st day of March 2010.

PACIFICORP

/s/ Douglas K. Stuver
Douglas K. Stuver
Senior Vice President and Chief Financial Officer
(principal financial and accounting officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Gregory E. Abel Gregory E. Abel	Chairman of the Board of Directors and Chief Executive Officer (principal executive officer)	March 1, 2010
/s/ Douglas K. Stuver Douglas K. Stuver	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	March 1, 2010
/s/ Douglas L. Anderson Douglas L. Anderson	Director	March 1, 2010
/s/ Micheal G. Dunn Micheal G. Dunn	Director	March 1, 2010
/s/ Brent E. Gale Brent E. Gale	Director	March 1, 2010
/s/ Patrick J. Goodman Patrick J. Goodman	Director	March 1, 2010
/s/ Natalie L. Hocken Natalie L. Hocken	Director	March 1, 2010
/s/ Mark C. Moench Mark C. Moench	Director	March 1, 2010
/s/ R. Patrick Reiten R. Patrick Reiten	Director	March 1, 2010
/s/ A. Richard Walje A. Richard Walje	Director	March 1, 2010

EXHIBIT INDEX

Exhibit No. **Description**

3.1* Third Restated Articles of Incorporation of PacifiCorp (Exhibit (3)b, Annual Report on Form 10-K for the year ended December 31, 1996, filed March 21, 1997, File No. 1-5152).

3.2* Bylaws of PacifiCorp, as amended May 23, 2005 (Exhibit 3.2, on Annual Report on Form 10-K for the year ended March 31, 2006, filed May 30, 2006, File No. 1-5152).

4.1* Mortgage and Deed of Trust dated as of January 9, 1989, between PacifiCorp and JP Morgan Chase Bank (formerly known as The Chase Manhattan Bank), Trustee, Ex. 4-E, Form 8-B, File No. 1-5152, as supplemented and modified by 23 Supplemental Indentures as follows:

Exhibit No.	File Type	File Date	File Number
(4)(b)	SE	November 2, 1989	33-31861
(4)(a)	8-K	January 9, 1990	1-5152
4(a)	8-K	September 11, 1991	1-5152
4(a)	8-K	January 7, 1992	1-5152
4(a)	10-Q	Quarter ended March 31, 1992	1-5152
4(a)	10-Q	Quarter ended September 30, 1992	1-5152
4(a)	8-K	April 1, 1993	1-5152
4(a)	10-Q	Quarter ended September 30, 1993	1-5152
(4)b	10-Q	Quarter ended June 30, 1994	1-5152
(4)b	10-K	Year ended December 31, 1994	1-5152
(4)b	10-K	Year ended December 31, 1995	1-5152
(4)b	10-K	Year ended December 31, 1996	1-5152
4(b)	10-K	Year ended December 31, 1998	1-5152
99(a)	8-K	November 21, 2001	1-5152
4.1	10-Q	Quarter ended June 30, 2003	1-5152
99	8-K	September 8, 2003	1-5152
4	8-K	August 24, 2004	1-5152
4	8-K	June 13, 2005	1-5152
4.2	8-K	August 14, 2006	1-5152
4	8-K	March 14, 2007	1-5152
4.1	8-K	October 3, 2007	1-5152
4.1	8-K	July 17, 2008	1-5152
4.1	8-K	January 8, 2009	1-5152

4.2* Third Restated Articles of Incorporation and Bylaws. See 3.1 and 3.2 above.

In reliance upon item 601(4)(iii) of Regulation S-K, various instruments defining the rights of holders of long-term debt of the Registrant and its subsidiaries are not being filed because the total amount authorized under each such instrument does not exceed 10% of the total assets of the Registrant and its subsidiaries on a consolidated basis. The Registrant hereby agrees to furnish a copy of any such instrument to the Commission upon request.

10.1 Summary of Key Terms of Named Executive Officer and Employee Director Compensation.

10.2* PacifiCorp Executive Voluntary Deferred Compensation Plan (Exhibit 10.3, Annual Report on Form 10-K, for the year ended December 31, 2007, filed February 29, 2008, File No. 1-5152).

10.3* Supplemental Executive Retirement Plan (Exhibit 10.7, Annual Report on Form 10-K, for the year ended March 31, 2005, filed May 27, 2005, File No. 1-5152).

10.4*	Amendment No. 10 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (Exhibit 10.5, Quarterly Report on Form 10-Q, filed August 7, 2006, File No. 1-5152).
10.5*	Amendment No. 11 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (Exhibit 10.6, Quarterly Report on Form 10-Q, filed August 7, 2006, File No. 1-5152).
10.6*	$700,000,000 Credit Agreement dated as of October 23, 2007 among PacifiCorp, The Banks Party thereto, The Royal Bank of Scotland plc, as Syndication Agent, and Union Bank of California, N.A., as Administrative Agent. (Exhibit 99, Quarterly Report on Form 10-Q, filed November 2, 2007, File No. 1-5152).
10.7*	$800,000,000 Amended and Restated Credit Agreement dated as of July 6, 2006 among PacifiCorp, The Banks Party Hereto, JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, and The Royal Bank of Scotland plc, as Syndication Agent. (Exhibit 99, Quarterly Report on Form 10-Q, filed August 4, 2006, File No. 1-5152).
10.8*	First Amendment dated as of April 15, 2009, amends that certain Credit Agreement, dated as of October 23, 2007, among PacifiCorp, the banks listed on the signatures pages thereto, the Royal Bank of Scotland plc, as Syndication Agent and Union Bank, N.A., (formerly known as Union Bank of California, N.A.), as administrative agent for the banks. (Exhibit 10.1, Quarterly Report on Form 10-Q, filed May 8, 2009, File No. 1-5152).
10.9*	First Amendment dated as of April 15, 2009, amends that certain Amended and Restated Credit Agreement, dated as of July 6, 2006, among PacifiCorp, the banks listed on the signature pages thereto, JPMorgan Chase Bank, N.A. as Administrative agent and issuing bank and the Royal Bank of Scotland plc, as Syndication Agent. (Exhibit 10.2, Quarterly Report on Form 10-Q, filed May 8, 2009, File No. 1-5152).
10.10	Amendment No. 1 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 28, 2008.
12.1	Statements of Computation of Ratio of Earnings to Fixed Charges.
12.2	Statements of Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends.
14.1*	Code of Ethics (Exhibit 14.1, Transition Report on Form 10-K for the nine-month period ended December 31, 2006, filed March 2, 2007, File No. 1-5152).
23.1	Consent of Deloitte & Touche LLP.
31.1	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*Incorporated herein by reference.

Appendix B

Pacific Power
State of California
Present Rates plus Klamath Impact in GRC and Proposed Klamath Dam Removal Surcharge for January 1, 2011

Tariff Schedules			Present Rates	Estimated Klamath in GRC Rate Equivalencies	Proposed Dam Removal Surcharge S-199	Combined Rate	
Schedule D (Standard Residential)							
Basic Charge			$5.93			$5.93	/month
Energy Charge							
Baseline kWh			10.385		0.179	10.564	¢/kWh
Non-Baseline kWh			12.048		0.179	12.227	¢/kWh
Schedule DL-6 (Residential CARE)							
Basic Charge			$4.74			$4.74	/month
Energy Charge							
Baseline kWh			7.902	0.041	0.179	8.122	¢/kWh
Non-Baseline kWh			9.232	0.041	0.179	9.452	¢/kWh
Schedule OL-15							
type	*lumen*	*kWh*		0.026	0.339		¢/kWh
Mercury Vapor	7,000	76	$15.28	$0.02	$0.26	$15.56	/Lamp
Mercury Vapor	21,000	172	$31.41	$0.04	$0.58	$32.03	/Lamp
Mercury Vapor	55,000	412	$69.79	$0.11	$1.40	$71.30	/Lamp
High Pressure Sodium	5,800	31	$15.17	$0.01	$0.11	$15.29	/Lamp
High Pressure Sodium	22,000	85	$24.95	$0.02	$0.29	$25.26	/Lamp
High Pressure Sodium	50,000	176	$42.53	$0.05	$0.60	$43.18	/Lamp
Schedule PA-20							
Basic Charge - Annually (billed in November)							
1 Phase Any Size, 3 Phase <= 50kW			$68.10			$68.10	
3 Phase Load Size > 50 kW			$140.65			$140.65	
Distribution Demand Charge - Annually (billed in November)			$14.73			$14.73	/kW
Generation & Transmission Demand Charge			$0.70			$0.70	/kW
Energy Charge			9.153	0.037	0.192	9.382	¢/kWh
Reactive Power			$0.60			$0.60	/kVar
Schedule A-25 Secondary							
Basic Charge							
1 Phase			$11.17			$11.17	/month
3 Phase			$15.34			$15.34	/month
Energy Charge			12.339	0.040	0.249	12.628	¢/kWh
Schedule A-25 Primary							
Basic Charge							
1 Phase			$11.17			$11.17	/month
3 Phase			$15.34			$15.34	/month
Energy Charge			12.217	0.040	0.249	12.506	¢/kWh
High Voltage Charge			$60.00			$60.00	/month
Schedule AWH-31							
Basic Charge							
1 Phase			$7.80			$7.80	/month
3 Phase			$10.60			$10.60	/month
Energy Charge			10.622	0.040	0.249	10.911	¢/kWh

Pacific Power
State of California
Present Rates plus Klamath Impact in GRC and Proposed Klamath Dam Removal Surcharge for January 1, 2011

Tariff Schedules	Present Rates	Estimated Klamath in GRC Rate Equivalencies	Proposed Dam Removal Surcharge S-199	Combined Rate	
Schedule A-32 Secondary					
Basic Charge					
1 Phase	$11.17			$11.17	/month
3 Phase	$15.34			$15.34	/month
Distribution Demand Charge	$1.39			$1.39	/kW
Generation & Transmission Demand Charge	$0.93			$0.93	/kW
Energy Charge	10.085	0.041	0.224	10.350	¢/kWh
Reactive Power	$0.60			$0.60	/kVar
Schedule A-32 Primary					
Basic Charge					
1 Phase	$11.17			$11.17	/month
3 Phase	$15.34			$15.34	/month
Distribution Demand Charge	$0.97			$0.97	/kW
Generation & Transmission Demand Charge	$0.93			$0.93	/kW
Energy Charge	9.983	0.041	0.224	10.248	¢/kWh
Reactive Power	$0.60			$0.60	/kVar
High Voltage Charge	$60.00			$60.00	/month
Schedule A-36 Secondary					
Basic Charge	$200.92			$200.92	/month
Distribution Demand Charge	$2.56			$2.56	/kW
Generation & Transmission Demand Charge	$2.32			$2.32	/kW
Energy Charge	7.566	0.040	0.186	7.792	¢/kWh
Reactive Power	$0.60			$0.60	/kVar
Schedule A-36 Primary					
Basic Charge	$200.92			$200.92	/month
Distribution Demand Charge	$1.79			$1.79	/kW
Generation & Transmission Demand Charge	$2.32			$2.32	/kW
Energy Charge	7.491	0.040	0.186	7.717	¢/kWh
Reactive Power	$0.60			$0.60	/kVar
High Voltage Charge	$60.00			$60.00	/month
Schedule AT-48 Secondary					
Basic Charge	$401.86			$401.86	/month
Distribution Demand Charge	$1.72			$1.72	/kW
Generation & Transmission Demand Charge (Summer)	$1.13			$1.13	/kW
Generation & Transmission Demand Charge (Winter)	$2.21			$2.21	/kW
Energy Charge	6.484	0.038	0.140	6.662	¢/kWh
Reactive Power	$0.60			$0.60	/kVar
Schedule AT-48 Primary/Transmission					
Basic Charge	$401.86			$401.86	/month
Distribution Demand Charge	$1.20			$1.20	/kW
Generation & Transmission Demand Charge (Summer)	$1.13			$1.13	/kW
Generation & Transmission Demand Charge (Winter)	$2.21			$2.21	/kW
Energy Charge	6.419	0.038	0.140	6.597	¢/kWh
Reactive Power	$0.60			$0.60	/kVar
High Voltage Charge	$60.00			$60.00	/month

Pacific Power
State of California
Present Rates plus Klamath Impact in GRC and Proposed Klamath Dam Removal Surcharge for January 1, 2011

Tariff Schedules				Present Rates	Estimated Klamath in GRC Rate Equivalencies	Proposed Dam Removal Surcharge S-199	Combined Rate
Schedule LS-51							
	lumen	*Watts*	*kWh*		0.026	0.389	¢/kWh
High Pressure Sodium	5,800	70	31	$9.41	$0.01	$0.12	$9.54 /Lamp
High Pressure Sodium	9,500	100	44	$10.63	$0.01	$0.17	$10.81 /Lamp
High Pressure Sodium	16,000	150	64	$14.58	$0.02	$0.25	$14.85 /Lamp
High Pressure Sodium	22,000	200	85	$18.29	$0.02	$0.33	$18.64 /Lamp
High Pressure Sodium	27,500	250	115	$24.30	$0.03	$0.45	$24.78 /Lamp
High Pressure Sodium	50,000	400	176	$35.51	$0.05	$0.68	$36.24 /Lamp
Decorative Series 1							
High Pressure Sodium	9,500	100	44	$31.37	$0.01	$0.17	$31.55 /Lamp
High Pressure Sodium	16,000	150	64	$32.76	$0.02	$0.25	$33.03 /Lamp
Decorative Series 2							
High Pressure Sodium	9,500	100	44	$25.54	$0.01	$0.17	$25.72 /Lamp
High Pressure Sodium	16,000	150	64	$27.15	$0.02	$0.25	$27.42 /Lamp
Schedule LS-52							
	lumen	*Watts*	*kWh*		0.026	1.392	¢/kWh
High Pressure Sodium	5,800	70	31	$36.86	$0.01	$0.43	$37.30 /Lamp
High Pressure Sodium	9,500	100	44	$38.71	$0.01	$0.61	$39.33 /Lamp
High Pressure Sodium	22,000	200	85	$49.58	$0.02	$1.18	$50.78 /Lamp
High Pressure Sodium	50,000	400	176	$71.30	$0.05	$2.45	$73.80 /Lamp
Schedule LS-53							
	lumen	*Watts*	*kWh*		0.026	0.195	¢/kWh
High Pressure Sodium	5,800	70	31	$3.80	$0.01	$0.06	$3.87 /Lamp
High Pressure Sodium	9,500	100	44	$5.35	$0.01	$0.09	$5.45 /Lamp
High Pressure Sodium	16,000	150	64	$7.71	$0.02	$0.12	$7.85 /Lamp
High Pressure Sodium	22,000	200	85	$10.38	$0.02	$0.17	$10.57 /Lamp
High Pressure Sodium	27,500	250	115	$13.87	$0.03	$0.22	$14.12 /Lamp
High Pressure Sodium	50,000	400	176	$21.47	$0.05	$0.34	$21.86 /Lamp
Non-Listed Luminaire				12.172	0.026	0.195	12.393 ¢/kWh
Schedule OL-42							
Basic Charge							
Single Phase				$9.94			$9.94 /month
Three Phase				$13.62			$13.62 /month
All kWh				14.067	0.026	0.257	14.350 ¢/kWh

Pacific Power
State of California
Present Rates plus Klamath Impact in GRC and Proposed Klamath Dam Removal Surcharge for January 1, 2011

Tariff Schedules			Present Rates	Estimated Klamath in GRC Rate Equivalencies	Proposed Dam Removal Surcharge S-199	Combined Rate
Schedule LS-58						
Class A	*lumen*	*kWh*		0.026	0.223	¢/kWh
Incandescent	1,000	37	$5.16	$0.01	$0.08	$5.25 /Lamp
Incandescent	2,500	73	$10.23	$0.02	$0.16	$10.41 /Lamp
Incandescent	4,000	119	$16.67	$0.03	$0.27	$16.97 /Lamp
Incandescent	6,000	163	$22.85	$0.04	$0.36	$23.25 /Lamp
Mercury Vapor	7,000	76	$10.63	$0.02	$0.17	$10.82 /Lamp
Mercury Vapor	21,000	172	$24.12	$0.04	$0.38	$24.54 /Lamp
Mercury Vapor	55,000	412	$57.71	$0.11	$0.92	$58.74 /Lamp
Fluorescent	21,400	162	$22.83	$0.04	$0.36	$23.23 /Lamp
Class B						
Incandescent	1,000	37	$6.60	$0.01	$0.08	$6.69 /Lamp
Incandescent	2,500	73	$11.71	$0.02	$0.16	$11.89 /Lamp
Incandescent	4,000	119	$18.20	$0.03	$0.27	$18.50 /Lamp
Incandescent	6,000	163	$24.45	$0.04	$0.36	$24.85 /Lamp
Mercury Vapor	7,000	76	$11.49	$0.02	$0.17	$11.68 /Lamp
Mercury Vapor	21,000	172	$25.04	$0.04	$0.38	$25.46 /Lamp
Mercury Vapor	55,000	412	$58.96	$0.11	$0.92	$59.99 /Lamp
Fluorescent	21,400	162	$25.09	$0.04	$0.36	$25.49 /Lamp

Pacific Power
State of California
Forecast 12 Months Ending December 2011
Klamath Impact in General Rate Case - Estimated Rate Equivalencies

Class / Schedule		kWh	Proposed GRC Non-NPC Generation Revenues	Rate Spread	Klamath Revenue in GRC	Estimated Rate Equivalencies ¢ per kWh
Residential Service	D	394,810,883	$13,342,690	48.95%	$161,078	0.041
Multi-Family - Master Metered	DM-9	255,208	$8,015	0.03%	$97	0.041
Multi-Family - Submetered	DS-8	1,336,216	$27,593	0.10%	$333	0.041
Small General Service - < 20 kW	A-25/AWH-31	61,935,978	$2,050,504	7.52%	$24,754	0.040
Small General Service - 20 kW & Over	A-32	52,718,752	$1,770,924	6.50%	$21,379	0.041
Large General Service - 100 kW & Over	A-36	104,693,175	$3,454,755	12.67%	$41,707	0.040
Large General Service - 500 kW & Over	AT-48	113,573,565	$3,588,528	13.16%	$43,322	0.038
Agricultural Pumping Service	PA-20	95,186,258	$2,946,130	10.81%	$35,567	0.037
Total Lighting		3,759,965	$82,167	0.30%	$992	0.026
Total Sales		828,270,000	$27,399,669		$329,230	
Employee Discount			($12,391)	-0.05%	($150)	
Total Sales with Employee Discount		828,270,000	$27,387,214		$329,080	

* Proposed Non-NPC Generation Revenues shown in Exhibit PPL/803 in A.09-11-015 (GRC).

PACIFIC POWER
STATE OF CALIFORNIA
Calculation of Klamath Dam Removal Surcharge
Forecast 12 Months Ending December 2011

Line No.	Description (1)	Sch. (2)	No. of Customers (3)	KWH (4)	Present Generation Revenues (5)	Klamath Dam Removal Surcharge Rates ¢/kWh (6)	Klamath Dam Removal Surcharge Revenues (7) (6)*(4)
	Residential						
1	Residential Service	D/DL-6	36,532	394,810,883	$19,480,084	0.179	$706,711
2	Multi-Family - Master Metered	DM-9	8	255,208	$12,597	0.179	$457
3	Multi-Family - Submetered	DS-8	14	1,336,216	$64,886	0.179	$2,392
4	**Total Residential**		36,554	396,402,307	$19,557,567	0.179	$709,560
	Commercial & Industrial						
5	General Service - < 20 kW	A-25/AWH-31	7,208	61,935,978	$3,900,168	0.249	$154,221
6	General Service - 20 kW & Over	A-32	893	52,718,752	$3,082,024	0.224	$118,090
7	General Service - 100 kW & Over	A-36	290	104,693,175	$5,496,931	0.186	$194,729
8	Large General Service - 500 kW & Over	AT-48	17	113,573,565	$6,041,257	0.140	$159,003
9	Agricultural Pumping Service	PA-20	2,027	95,186,258	$4,824,773	0.192	$182,758
10	**Total Commercial & Industrial**		10,435	428,107,728	$23,345,152		$808,801
	Lighting						
11	Outdoor Area Lighting Service	OL-15	926	1,077,000	$60,647	0.339	$3,651
12	Airway & Athletic Lighting	OL-42	40	202,965	$10,699	0.257	$522
13	Street Lighting Service	LS-51	74	694,980	$41,042	0.389	$2,703
14	Street Lighting Service	LS-52	5	7,772	$825	1.392	$108
15	Street Lighting Service	LS-53	118	1,531,797	$75,198	0.195	$2,987
16	Street Lighting Service	LS-58	23	245,451	$12,399	0.223	$547
17	**Total Lighting**		1,186	3,759,965	$200,810		$10,519
18	**Total**		48,174	828,270,000	$43,103,529		$1,528,879

Notes:
1 Present revenues based on rates effective January 1, 2010.

Appendix C

PacifiCorp
Summary of Earnings
Twelve Months Ended June 30, 2009

Line	Item	Total Company	California
1	Operating Revenue	$4,391,314,669	$104,400,452
2	Operating Expenses	$3,671,519,237	$86,014,043
3	Operating Revenue for Return	$719,795,432	$18,386,409
4	Total Rate Base	$10,770,352,154	$236,512,185
5	Return on Rate Base	6.68%	7.77%