PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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November 14, 2014

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Washington Utilities and Transportation Commission
1300 S. Evergreen Park Drive S.W.
P.O. Box 47250
Olympia, WA 98504-7250

Attention: Steven V. King
Executive Director and Secretary

RE: Consolidated Dockets UE-140762, UE-140617, UE-140094, and UE-131384—Pacific Power & Light Company's Rebuttal Testimony and Exhibits

Dear Mr. King:

Pacific Power & Light Company, a division of PacifiCorp, submits its rebuttal testimony and exhibits for filing in this proceeding.

Confidential material in support of the filing is being provided subject to the terms and conditions of Order 02 in Docket UE-140762.

Please direct any informal inquiries about this filing to Natasha Siores, Director, Regulatory Affairs & Revenue Requirement, at (503) 813-6583.

Sincerely,

RBDalley

R. Bryce Dalley
Vice President, Regulation

Enclosures

cc: UE-140762, UE-140617, UE-140094, and UE-131384 Service Lists

Attachment A

Pacific Power & Light Company, a division of PacifiCorp ("PAC")
General Rate Case Filing
Index of Files on CDs
November 14, 2014

CD 1. WA UE-140762_PAC Non-Confidential (PACNov2014)

A. UE_140762_PAC Index of Files on CD (PACNov2014)
B. UE_140762_PAC Cover Letter (PACNov2014)
C. UE_140762_PAC Certificate of Service (PACNov2014)
D. UE_140762_PAC Testimony and Exhibits (PACNov2014)
   A. UE-140762_PAC Dalley (PACNov2014)
   B. UE-140762_PAC Strunk (PACNov2014)
   C. UE-140762_PAC Williams (PACANov2014)
   D. UE-140762_PAC Duvall (PACNov2014)
   E. UE-140762_PAC Crane (PACNov2014)
   F. UE-140762_PAC Vail (PACNov2014)
   G. UE-140762_PAC Ralston (PACNov2014)
   H. UE-140762_PAC Wilson (PACNov2014)
   I. UE-140762_PAC Ross (PACNov2014)
   J. UE-140762_PAC Siores (PACNov2014)
   K. UE-140762_PAC Steward (PACNov2014)
E. UE_140762_PAC Workpapers (PACNov2014)
   01 Dalley Workpapers (PACNov2014)
   02 Strunk Workpapers (PACNov2014)
   03 Williams Workpapers (PACNov2014)
   04 Duvall Workpapers (PACNov2014)
   05 Siores Workpapers (PACNov2014)
   06 Steward Workpapers (PACNov2014)

CD 2. WA UE-140762_PAC Confidential (PACNov2014)

A. UE-140762_PAC Dalley CONF Exhibit (PACNov2014)
B. UE-140762_PAC Strunk CONF Exhibit (PACNov2014)
C. UE-140762_PAC Duvall CONF Exhibit (PACNov2014)
D. UE-140762_PAC Crane CONF Testimony (PACNov2014)
E. UE-140762_PAC Steward CONF Exhibit (PACNov2014)
F. Duvall Confidential Workpapers (PACNov2014)
G. Crane Confidential Workpapers (PACNov2014)

CERTIFICATE OF SERVICE

I hereby certify that I have this day served this document upon all parties of record in Dockets UE-140762, UE-140617, UE-131384, UE-140094 by electronic mail and/or Overnight Delivery.

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DATED at Portland, OR this 14th day of November 2014.

Carrie Meyer
Supervisor, Regulatory Operations

Exhibit No. RBD-3T
Docket UE-140762 *et al.*
Witness: R. Bryce Dalley

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF R. BRYCE DALLEY

November 2014

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ATTACHED EXHIBITS

Q. Are you the same R. Bryce Dalley who previously submitted direct testimony in this case on behalf of Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp?

A. Yes.

PURPOSE OF TESTIMONY

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

A. My rebuttal testimony responds to the regulatory policy issues raised in the testimonies of Staff of the Washington Utilities and Transportation Commission (Commission), the Public Counsel Division of the Attorney General's Office (Public Counsel), and Boise White Paper, LLC (Boise). I also discuss current trends in the electric industry as a whole that require a supportive regulatory environment for investor-owned utilities like Pacific Power.

Q. Has the Company's recommended revenue requirement increase changed in its rebuttal filing?

A. Yes. As discussed in the rebuttal testimony of Ms. Natasha C. Siores, an overall base price increase of $31.9 million is required to produce the 10.0 percent return on equity (ROE) requested in this case. This is an increase from the $27.2 million requested in the initial filing and is driven primarily by the Company's net power cost update, which is addressed in the rebuttal testimonies of Mr. Gregory N. Duvall and Ms. Cindy A. Crane. As noted by Mr. Duvall, because this update is occurring in rebuttal testimony, the Company does not object to parties addressing the Company's net power cost update in supplemental pre-filed testimony or in testimony at the hearing, provided the Company is given the opportunity to respond through written or oral testimony.

POLICY OVERVIEW

Q. Please address the current critical policy issues facing the Company.

A. Along with the electric industry as a whole, the Company is in the midst of a period of significant transformation. In response to environmental concerns, Washington, like many states, has adopted new laws fast-tracking the development of renewable resources and distributed generation to produce carbon-free electricity, reduce the carbon intensity of the electric grid, and replace coal-fired generation.

These policy changes have created—and will continue to create—challenges for the Company. Similar energy policy initiatives are being promoted by federal agencies, notably the U.S. Environmental Protection Agency (EPA) through its proposed rules under Sections 111(b) and 111(d) of the Clean Air Act. To allow the Company to adapt to the changing electric industry landscape, the Company needs supportive regulatory treatment from the Commission.

Q. What specific Washington laws and policies have contributed to the challenges faced by the Company?

A. Over the last decade, the state of Washington has steadily moved toward requiring more renewable and less carbon-intense energy supplies. In this process, Washington has often taken a regional approach, working in collaboration with Oregon, California, and other states in the west.

In 2006, Washington's Energy Independence Act (EIA) was enacted by voter initiative. The EIA includes a renewable portfolio standard, requiring Washington electrical utilities to supply retail customers with increasing percentages of electricity from renewable resources, such as wind or solar generating facilities. The EIA is intended to encourage the development of renewable energy facilities in both Washington and the Pacific Northwest region.[1] To that end, the legislature amended the EIA in 2012 to specifically allow utilities to use resources outside of Washington to satisfy the EIA's requirements.[2]

In 2007, the legislature enacted Washington's Greenhouse Gas Emissions Performance Standard (EPS).[3] The EPS caps greenhouse gas (GHG) emissions for new electrical generation resources and encourages utilities to increase the use of "renewable energy sources."[4] The legislature specifically found that "Washington has been a leader in actions to slow the increase of greenhouse gases emissions, such as . . . increasing renewable energy sources by electric utilities," and the EPS is intended to further reduce greenhouse gas emissions used to generate electricity used to serve Washington customers.[5]

In 2008, Washington enacted the Climate Action and Green Jobs bill, which requires the state to reduce its GHG emissions by 70 percent of expected levels (50 percent below 1990 levels) by 2050, and promotes "renewable energy development and generation."[6]

[1] RCW 19.285.020 (EIA provides that Washington should increase the use of "renewable energy facilities").
[2] Laws of 2013, ch. 61 (amending the definition of "eligible renewable resource" in RCW 19.285.030, effective July 28, 2013). Now, RCW 19.285.030(12)(a) and (e) define "eligible renewable resource" to include facilities located in the Pacific Northwest as well as facilities in other states where the qualifying utility has a renewable resource and serves retail customers.
[3] *See* RCW 80.80.
[4] RCW 80.80.005(1)(d).
[5] *Id.*
[6] RCW 70.235.005(1).

In 2010, the legislature directed Washington's State Energy Office to prepare a state energy strategy, finding that "the nation and the world have started the transition to a clean energy economy, with significant improvements in energy efficiency and investments in new clean and renewable energy resources and technologies."[7] The legislature also declared "that it is the continuing purpose of state government . . . to promote energy self-sufficiency through the use of indigenous and renewable energy sources, consistent with the promotion of reliable energy sources[.]"[8] One of the key principles underlying the Washington State Energy Strategy adopted under this directive in 2012 is for Washington to "[b]uild on the advantage provided by the state's clean regional electrical grid by expanding and integrating additional carbon-free and carbon-neutral generation."[9]

In 2013, Washington passed a second Climate Action bill, designed to provide additional resources to assist Washington in meeting the GHG targets set in Washington's original Climate Action bill.[10]

In April 2014, Governor Jay Inslee issued an Executive Order specifically recognizing that Washington joined California and Oregon in "calling for additional West Coast actions on climate leadership, clean transportation, and clean energy and infrastructure."[11]

This Executive Order followed the issuance of the Pacific Coast Action Plan on Climate and Energy, which was signed by representatives of Washington, British Columbia, California, and Oregon. The Pacific Coast Action Plan acknowledges that

[7] RCW 43.21F.010(2).
[8] RCW 43.21F.010(3).
[9] RCW 43.21F.088(1)(g).
[10] Laws of 2013, ch. 6.
[11] Executive Order 14-04 at 2 (Apr. 29, 2014).

the signatories have "reduced greenhouse gas emissions by adopting regulatory, policy, and market-based measures that shift energy generation to clean and renewable sources."[12] Further, the signatories agreed that "meaningful coordination and linkage between states and provinces . . . to reduce greenhouse gas emissions can improve the effectiveness of these actions, [and] increase their overall positive impact[.]"[13] Thus, "where possible, California, British Columbia, Oregon and Washington will link programs for consistency and predictability and to expand opportunities to grow the region's low-carbon economy."[14]

Q. Are there policy developments at the national level that are also driving major changes in the electric industry?

A. Yes. During the pendency of this case, the EPA released its Clean Power Plan Proposal to regulate GHG emissions from existing generation plants under Section 111(d) of the Clean Air Act. The EPA is currently scheduled to issue its final rule in June 2015. In his testimony, Mr. Kurt G. Strunk addresses utility investor risk associated with the draft rules under Section 111(d).

Q. Please explain how these policy issues are relevant to the Company's proposals in this case.

A. The Company made several proposals in its initial filing intended to address the market transformation that is occurring while protecting the Company from the adverse impacts that are a result of changing state laws and policies.

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[12] Pacific Coast Action Plan on Climate and Energy at 1 (Oct. 28, 2013). A copy of this plan is attached as Exhibit No. RBD-4.
[13] *Id.*
[14] *Id.*

First, the Company renewed its request for a change to the West Control Area inter-jurisdictional allocation methodology (WCA) to allow recovery of the costs associated with power purchase agreements (PPAs) with all qualifying facilities (QFs) in the west control area, all of which are renewable resources. This proposal is discussed in more detail in the direct and rebuttal testimonies of Mr. Duvall. The Company also presented two alternatives for reflecting the costs of west control area QF PPAs in retail rates as discussed further in Mr. Duvall's testimonies.

Second, the Company proposed use of its actual capital structure for ratemaking purposes to ensure financial strength and ready access to low-cost financing, which in turn supports further investments in utility infrastructure to maintain safe, reliable, and cost-effective service and to facilitate compliance with existing and emerging environmental policies. The Company also presented an alternative weighted average cost of capital that more accurately reflects the impact of a hypothetical equity component on cost of equity and cost of debt. The Company's capital structure and costs of debt and equity are more thoroughly addressed in the direct and rebuttal testimonies of Mr. Strunk and Mr. Bruce N. Williams.

Third, the Company proposed a renewable resource tracking mechanism (RRTM) to mitigate the risks inherent in the Company's growing portfolio of renewable resources and ensure that both the Company and customers are protected from the volatility inherent in renewable generation. This proposal is discussed in the direct and rebuttal testimonies of Mr. Duvall.

Fourth, the Company proposed an increase in its residential basic charge to better reflect the fixed costs incurred to provide service, consistent with principles of cost causation. The cost-based basic charge better positions the Company to respond to the challenges resulting from declining residential use and increasing distributed generation by mitigating cost-shifting and supporting the Company's ability to reasonably recover more of its fixed costs. Similarly, the Company also supports the continued use of its current two-tier energy rate structure, as opposed to Staff's three-tier energy rates, as an additional way to mitigate unwarranted cost shifting. In addition, moving revenue recovery into a third tier would put the Company's recovery of fixed costs at risk and dependent upon weather conditions. The Company's proposed rate design is discussed in the direct and rebuttal testimonies of Ms. Joelle R. Steward.

Finally, to better position the Company to respond to changing circumstances in a timely and efficient manner, the Company also proposed several modifications to the historical test period convention to address chronic under-recovery and regulatory lag. These modifications build upon the foundation laid by the Commission in the Company's 2013 general rate case, Docket UE-130043 (2013 Rate Case), and include:

- Reflecting in retail rates significant capital additions that will be in service and used and useful for Washington customers before the beginning of the rate-effective period;
- Reflecting rate base balances at end-of-period levels rather than using the average-of-monthly-averages approach; and
- Using IHS Global Insight indices to escalate non-labor operations and maintenance (O&M) and administrative and general (A&G) expenses.

I address these proposed modifications, as well as the Company's proposed amortization of certain deferred accounting requests, in more detail below.

Q. Have you updated the table provided in your direct testimony demonstrating the Company's chronic under-earning in Washington from 2006 through 2012 to include the Company's 2013 earnings?

A. Yes. The results for 2013 have been added to the Table 1 below:[15]

TABLE 1

Washington Commission Basis Reports - Return on Equity									
	2006	2007	2008	2009	2010	2011	2012	2013	Average
Per Books	2.08%	2.72%	0.02%	6.13%	4.59%	5.64%	7.14%	4.95%	4.16%
Restated	3.49%	3.90%	3.53%	5.28%	6.69%	7.57%	6.99%	8.22%	5.71%
Pro Forma	2.48%	3.15%	5.65%	7.81%	6.23%	7.43%	7.26%	7.73%	5.97%
Authorized	10.20%	10.20%	10.20%	10.20%	10.20%	9.80%	9.80%	9.50%	10.01%
Variance (Per Books v. Authorized)	**-8.12%**	**-7.48%**	**-10.18%**	**-4.07%**	**-5.61%**	**-4.16%**	**-2.66%**	**-4.55%**	**-5.85%**

This table shows the Company's earnings continue to be at levels well below the Company's authorized ROE. In 2012, the Commission adopted supportive ratemaking treatment for Puget Sound Energy (PSE) expressly to address its under-earning.[16] The Company's historical earnings in Washington fall well below PSE's, demonstrating Pacific Power's need for similar support from the Commission.[17] As the business environment for electric utilities becomes more challenging in Washington, the Company's recommendations in this case are necessary to prevent further earnings deterioration.

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[15] The Company's Commission basis report for the period ending December 31, 2013, was filed April 29, 2014, and is available at the following link: http://www.utc.wa.gov/_layouts/CasesPublicWebsite/GetDocument.ashx?docID=4&year=2014&docketNumber=140739. The Company's 2013 restated ROE and pro forma ROE reflect net power cost levels that are approximately $15 million less (on a Washington-allocated basis) than the amount requested in the Company's rebuttal filing in this case This variance in net power costs represents over 200 basis points on equity.

[16] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-111048 et al., Order 08 ¶ 491 (May 7, 2012).

[17] According to testimony filed by PSE on November 5, 2014, in Docket UE-121697, from 2007 through 2013 PSE's authorized ROE has exceeded its normalized ROE by an average of 2.76 percent. *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-121697, Testimony of Daniel A. Doyle, Exhibit No. DAD-4T at 17-18 (Nov. 5, 2014). As shown in Table 1, in Washington, Pacific Power's average authorized ROE has exceeded its average per books ROE by 5.85 percent, exceeded its average restated ROE by 4.30 percent, and exceeded its average pro forma ROE by 4.04 percent.

PRO FORMA CAPITAL ADDITIONS

Q. What did the Company propose regarding pro forma capital additions in its initial filing?

A. The Company proposed including capital additions above $250,000 on a Washington-allocated basis that would be in service and used and useful before the beginning of the rate-effective period. These capital additions were discussed in the direct testimonies of Ms. Siores, Mr. Richard A. Vail, Mr. Mark R. Tallman, and Mr. Dana M. Ralston.

Q. Did Staff, Public Counsel, and Boise support the Company's pro forma capital additions?

A. Staff supports the Company's proposed pro forma additions, but proposes limiting the adjustment to reflect only actual plant in service through November 14, 2014, which is the date of the Company's rebuttal testimony.[18] Public Counsel supports including pro forma capital additions to address regulatory lag, but proposes the adjustment "should be limited only to the known and measurable amounts for projects that have actually been placed into service and are used and useful in providing service to customers."[19] Public Counsel proposes an adjustment to the Company's pro forma capital additions that is based upon plant in service balances as of August 31, 2014, consistent with actual plant addition data provided in discovery.[20] Boise does not support the Company's proposal and rejects all of the proposed pro forma capital additions except the Merwin fish collector.[21]

[18] Testimony of Betty A. Erdahl, Exhibit No. BAE-1T at 4.
[19] Revised Testimony of Donna R. Ramas, Exhibit No. DMR-1T at 15-16.
[20] *Id*. at 13-14, 16-17.
[21] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1T at 7.

Q. What is the Company's position regarding pro forma capital additions in its rebuttal filing?

A. The Company appreciates Staff's and Public Counsel's recognition that pro forma capital additions are a reasonable means of addressing under-recovery and mitigating regulatory lag. To respond to Staff's and Public Counsel's recommendations that only the known and measurable amounts for projects that have actually been placed in service be included in rates, the Company proposes in this case to limit its adjustment for pro forma capital additions to the amounts actually placed in service by the date of the Company's compliance filing. Consistent with this standard, the Company proposes to remove projects that are not placed in service by that date. This proposed update is similar to the net power cost update that the Company has made in its compliance filings in prior general rate cases.

Unlike Boise's recommended (and arguably punitive) approach to pro forma capital additions, the Company's proposal recognizes that including the costs of capital projects that are in service and used and useful for customers before the beginning of the rate-effective period: (1) appropriately reflects the cost to serve customers; (2) mitigates regulatory lag; and (3) encourages prudent investment in necessary infrastructure.

END-OF-PERIOD RATE BASE BALANCES

Q. Did the Company propose using end-of-period rate base balances in its initial filing as a means of mitigating regulatory lag?

A. Yes. Consistent with the Company's 2013 Rate Case, the Company reflected rate base balances at end-of-period levels.

Q. How did the parties respond to the Company's proposals?

A. Staff and Public Counsel do not contest the use of end-of-period rate base balances in this case. Boise rejects the Company's proposal, arguing that the approval of end-of-period rate base balances in the Company's 2013 Rate Case "has done little to assuage the frequency of the Company's rate filings."[22] Boise recommends using average-of-monthly-averages rate base balances, which would reduce revenue requirement by approximately $1.8 million.

Q. What is your response to Boise's recommendation?

A. Boise's recommendation does not recognize the fact that the Company is currently investing in its system to provide safe, reliable, and cost-effective service. Because the Company's rate base continues to grow, reflecting rate base using end-of-period balances more accurately reflects the cost to serve customers in the rate-effective period. In addition, the Commission's willingness to use end-of-period rate base balances is an encouraging step that supports future investments, including those that may be required to achieve state and federal energy and environmental goals.

IHS GLOBAL INSIGHT INDICES

Q. Please describe the Company's proposed pro forma adjustment using IHS Global Insight indices.

A. As discussed in my direct testimony and the testimony of Ms. Siores, the Company proposes to escalate non-labor O&M and A&G accounts using independent third-party escalation indices developed specifically for electric utilities.

[22] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1T at 17.

Q. How did the parties' respond to the Company's proposal?

A. Staff, Public Counsel, and Boise recommend rejecting the Company's proposal. Staff argues that use of the IHS Global Insight indices effectively create "a budgeted, future test year for ratemaking purposes" and are "overstated and unreliable."[23] Public Counsel argues that the use of the IHS Global Insight indices to escalate non-labor O&M and A&G expenses is inconsistent with use of a historical test period.[24] Boise states that the Company's proposed adjustment is not known and measurable.[25]

Q. Are the parties' criticisms of the Company's proposal well founded?

A. No, but the parties' positions are not surprising based on Commission precedent. The Company is asking the Commission to take incremental steps to provide the Company a more reasonable opportunity to recover its costs. It is undisputed that the Company has not recovered the full cost of serving its Washington customers since at least 2006. To address this chronic under-recovery and better position the Company to face the changing environmental landscape, the Company proposes easily auditable, discrete adjustments to the historical test period convention to more accurately reflect the costs anticipated during the rate-effective period. The IHS Global Insight adjustment is one of these discrete adjustments.

Q. Staff asserts that the IHS Global Insight indices are not reliable and overstated. Is there any merit to Staff's criticism?

A. No. IHS Global Insight is a national economic forecasting consulting company that is widely used to develop economic forecasts. The State of Washington's Economic and Revenue Forecast Council relies on IHS Global Insight data to develop economic

[23] Testimony of Jason L. Ball, Exhibit No. JLB-1T at 15-16.
[24] Revised Testimony of Donna R. Ramas, Exhibit No. DMR-1T at 30-31.
[25] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1T at 18.

forecasts for the state.[26] For the utility industry, IHS Global Insight provides industry-specific escalation indices, developed at the Federal Energy Regulatory Commission account functional level. A description of the model used by IHS Global Insight to develop its O&M and A&G indices is attached as Confidential Exhibit No. RBD-5C. IHS Global Insight is widely used and reliable, winning accolades for its accuracy.[27]

Staff relies on the Company's response to a data request to assert that the indices are unreliable.[28] Staff, however, misinterprets the Company's response. IHS Global Insight calculates the indices each quarter and provides an update for each year. Consistent with other economic indices, the key comparison is the year-to-year change. Staff mistakenly focuses on which year is used as the base year and not the year-to-year change, which is the basis of the adjustment.

DEFERRED ACCOUNTING REQUESTS

Q. Please describe the Company's deferred accounting requests.

A. As discussed in the Company's initial filing, as part of this case the Company is requesting amortization of several deferred accounting requests through a separate tariff rider, Schedule 92—Deferral Adjustments. These deferred accounting requests related to: (1) an extended outage at Unit 4 of the Colstrip generating plant; (2) depreciation expense; (3) low hydro conditions; and (4) the Merwin fish collector.

[26] *See* http://www.erfc.wa.gov/forecast/documents/rev20140219_color.pdf.
[27] *See* http://www.ihs.com/products/global-insight/accuracy-accolades.aspx.
[28] Testimony of Jason L. Ball, Exhibit JLB-1T at 18.

Q. Why is the Company seeking amortization of these deferred accounting requests?

A. Except the depreciation deferral, which results in a rate reduction for customers, each of these deferrals reflect actual costs prudently incurred by the Company in the course of providing safe, reliable, and cost-effective service to its Washington customers. These costs are not currently reflected in customer rates and will not be reflected in customer rates without amortization of the deferred amounts. As demonstrated in Table 1 above, the Company's earnings have been well below authorized levels. Allowing the Company to recover the full costs of unexpected events (like an extended outage or low hydro conditions) or the revenue requirement associated with a new environmental improvement investment required by federal agencies is fair and equitable for the Company and its customers. The Company's specific deferred accounting requests, and its response to the parties' positions on these requests, are discussed in more detail in the rebuttal testimonies of Mr. Duvall, Ms. Siores, and Mr. Ralston.

CONCLUSION

Q. What is your recommendation to the Commission?

A. The Company respectfully requests that the Commission approve the Company's requested revenue requirement increase, as well as the amortization of its deferred accounting requests, in order to create the supportive regulatory environment that is necessary to face the challenges presented by a period of significant industry transformation. This supportive regulatory environment will better position the

Company to effectively and efficiently respond to the rapidly evolving energy and environmental laws and policies.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit No. RBD-4
Docket UE-140762 *et al.*
Witness: R. Bryce Dalley

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

<table>
<tr><td>WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

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PACIFIC POWER & LIGHT COMPANY,

For an Order Approving Deferral of Costs Related to Declining Hydro Generation.</td><td>DOCKET UE-140094 (consolidated)</td></tr>
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PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF R. BRYCE DALLEY

Pacific Coast Action Plan on Climate and Energy (Oct. 28, 2013)

November 2014

Pacific Coast Action Plan *on* Climate and Energy

Preamble

The Governments of California, British Columbia, Oregon and Washington,

Pursuant to the *Memorandum to Establish the Pacific Coast Collaborative* of June 2008, as provided for in Article 6;

Affirming our shared vision of Pacific North America as a model of innovation that sustains our communities and creates jobs and new economic opportunities for our combined population of 53 million;

Recognizing that the Pacific Coast is a region bound together by a common geography, shared infrastructure and a regional economy with a combined GDP of US $2.8 trillion, which makes it the world's fifth largest;

Acknowledging the clear and convincing scientific evidence of climate change, ocean acidification and other impacts from increasing concentrations of carbon dioxide in the atmosphere, which threaten our people, our economy and our natural resources;

Emphasizing that states and provinces around the world are battling climate change through technology innovation and actions that limit greenhouse gas emissions and other air pollution while creating economic growth, consumer savings and new jobs;

Celebrating that our own governments have reduced greenhouse gas emissions by adopting regulatory, policy and market-based measures that shift energy generation to clean and renewable sources, manage energy use through greater efficiency and conservation, and enable and promote consumer choice for clean vehicles;

Recalling the findings of the 2012 *West Coast Clean Economy* report which projected 1.03 million new jobs could be created in key sectors, such as energy efficiency and advanced transportation, assuming the right policy environment;

Supporting positive federal action to combat climate change, including President Obama's climate action plan and proposed rules to limit greenhouse gas emissions from power plants;

Joining the growing international convergence on the need to secure an international agreement to reduce global greenhouse gas emissions, including discussions at the coming Conference of Parties meetings in Warsaw (2013), Lima (2014) and Paris (2015); and

Agreeing that meaningful coordination and linkage between states and provinces across North America and the world on actions to reduce greenhouse gas emissions can improve the effectiveness of these actions, increase their overall positive impact and build momentum for broader international coordination to combat climate change;

NOW THEREFORE HEREBY AGREE AS FOLLOWS:

I. Lead national and international policy on climate change with actions to:

Direct our relevant agencies and officials to work together to:

1) **Account for the costs of carbon pollution in each jurisdiction.**

   Oregon will build on existing programs to set a price on carbon emissions. Washington will set binding limits on carbon emissions and deploy market mechanisms to meet those limits. British Columbia and California will maintain their existing carbon-pricing programs. Where possible, California, British Columbia, Oregon and Washington will link programs for consistency and predictability and to expand opportunities to grow the region's low-carbon economy.

2) **Harmonize 2050 targets for greenhouse gas reductions and develop mid-term targets needed to support long-term reduction goals.**

   Climate scientists have identified the scale of greenhouse gas reductions that must be achieved globally to stabilize the climate. Where they have not already done so, California, British Columbia, Oregon and Washington will establish long-term reduction targets that reflect these scientific findings. To advance long-term reductions, Washington already has in place a mid-term 2035 target. California and Oregon will establish their own mid-term targets. British Columbia has already legislated 2020 and 2050 targets and will explore whether setting a mid-term target will aid their achievement.

3) **Affirm the need to inform policy with findings from climate science.**

   Leaders of California, British Columbia, Oregon and Washington affirm the scientific consensus on the human causes of climate change and its very real impacts, most recently documented by scientists around the world in the Intergovernmental Panel on Climate Change's *Fifth Assessment Report* released in September 2013, as well as other reports such as the *Scientific Consensus on Maintaining Humanity's life Support Systems in the 21st Century*. Governmental actions should be grounded in this scientific understanding of climate change.

4) **Cooperate with national and sub-national governments around the world to press for an international agreement on climate change in 2015.**

   The governments of California, British Columbia, Oregon and Washington will join with other governments to build a coalition of support for national and international climate action, including securing an international agreement at the Conference of Parties in Paris in 2015. The governments of California, British Columbia, Oregon and Washington will coordinate the activities they undertake with other sub-national governments and combine these efforts where appropriate.

5) **Enlist support for research on ocean acidification and take action to combat it.**

   Ocean health underpins our coastal shellfish and fisheries economies. The governments of California, British Columbia, Oregon and Washington will urge the American and Canadian federal governments to take action on ocean acidification, including crucial research, modeling and monitoring to understand its causes and impacts.

II. Transition the West Coast to clean modes of transportation and reduce the large share of greenhouse gas emissions from this sector with actions to:

1) **Adopt and maintain low-carbon fuel standards in each jurisdiction.**

   Oregon and Washington will adopt low-carbon fuels standards, and California and British Columbia will maintain their existing standards. Over time, the governments of California, British Columbia, Oregon and Washington will work together to build an integrated West Coast market for low-carbon fuels that keeps energy dollars in the region, creates economic development opportunities for regional fuel production, and ensures predictability and consistency in the market.

2) **Take actions to expand the use of zero-emission vehicles, aiming for 10 percent of new vehicle purchases in public and private fleets by 2016.**

The Pacific Coast already has the highest penetration of electric cars in North America. The governments of California, British Columbia, Oregon and Washington will work together towards this ambitious new target by supporting public and private fleet managers to shift their procurement investments to catalyze toward electric car purchases and by continuing to invest in necessary infrastructure to enable low-carbon electric transportation.

3) **Continue deployment of high-speed rail across the region.**

Providing high-speed passenger rail service is an important part of the solution to expand regional clean transportation, improve quality of life and advance economic growth. The governments of California, British Columbia, Oregon and Washington continue to support the Pacific Coast Collaborative's Vision for high speed rail in the region, and will continue to seek opportunities to invest in rail infrastructure that moves people quickly, safely and efficiently, and encourages innovation in rail technology manufactured in the region.

4) **Support emerging markets and innovation for alternative fuels in commercial trucks, buses, rail, ports and marine transportation.**

The Pacific Coast of North America is emerging as a center of private sector innovation and investment in cleaner fuels and engine technologies for heavy-duty trucks and buses, rail, ports and marine transportation. The governments of California, British Columbia, Oregon and Washington will develop targets and action plans to accelerate public and private investment in low-carbon commercial fleets and support the market transition to biofuels, electricity, natural gas and other low-carbon fuels in local and export markets.

III. Invest in clean energy and climate-resilient infrastructure with actions to:

1) **Transform the market for energy efficiency and lead the way to "net-zero" buildings.**

Energy efficiency is the lowest cost way to reduce greenhouse gas emissions while creating good local jobs. The governments of California, British Columbia, Oregon and Washington will work to harmonize appliance standards, increase access to affordable financing products, and support policy that ensures that energy efficiency is valued when buildings are bought and sold. Our efforts intend to build a vibrant, growing regional market for energy efficiency products and services.

2) **Support strong federal policy on greenhouse gas emissions from power plants.**

The governments of California, British Columbia, Oregon and Washington will support the U.S. Environmental Protection Agency's initiative to regulate greenhouse gas emissions from power plants and emphasize the importance of allowing state flexibility to design ambitious reduction programs within this regulation. Our jurisdictions will also coordinate and provide joint testimony in federal proceedings on greenhouse gas emissions when appropriate.

3) **Make infrastructure climate-smart and investment-ready.**

The West Coast Infrastructure Exchange (WCX) is demonstrating how to attract private capital for infrastructure projects while increasing climate resilience through best practices and certification standards. To scale up these efforts, the governments of California, Oregon and Washington will sponsor pilot projects with local governments, state agencies and the WCX. WCX also works closely with Partnerships BC, a center of infrastructure financing expertise established by the government of British Columbia that has helped to secure financing for over 40 projects worth more than C$17 billion.

4) **Streamline permitting of renewable energy infrastructure.**

Meeting ambitious carbon-reduction goals will require scaling up wind, solar and other forms of renewable energy and effectively bringing clean power to customers in California, Oregon and Washington. Drawing on emerging models in California and the Pacific Northwest, the governments of California, Oregon and Washington will work with permitting agencies to streamline approval of renewables projects to increase predictability, encourage investment and drive innovation.

5) **Support integration of the region's electricity grids.**

Connecting the markets for buying and selling wholesale electricity in our region can increase local utilities' flexibility and reliability and provide consumer savings by enabling use of a wide variety of energy sources across the region. Integrating our region's electricity markets also expands energy users' access to renewable energy sources, such as solar and wind power.

IV. Interpretation

This Action Plan is intended to spur finding new, smart ways for our governments, agencies and staff to work together, and with other governments and non-government partners, as appropriate, to add value, efficiency and effectiveness to existing and future initiatives, and to reduce overlap and duplication of effort, with the objective of reducing, not increasing, resource demands to achieve objectives that are shared.

V. Limitations

This Action Plan shall have no legal effect; impose no legally binding obligation enforceable in any court of law or other tribunal of any sort, nor create any funding expectation; nor shall our jurisdictions be responsible for the actions of third parties or associates.

Signed at San Francisco, California, on the occasion of the Fourth Annual Leaders' Forum of the Pacific Coast Collaborative, this 28th day of October, 2013.

Original signed by

Edmund G. Brown Jr.
Governor of California

Original signed by

Christy Clark
Premier of British Columbia

Original signed by

John A. Kitzhaber
Governor of Oregon

Original signed by

Jay Inslee
Governor of Washington

Confidential Per Protective Order in UTC Docket UE-140762
Exhibit No. RBD-5C
Docket UE-140762 *et al.*
Witness: R. Bryce Dalley

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

CONFIDENTIAL EXHIBIT OF R. BRYCE DALLEY

IHS Global Insight—"The Power Planner"

November 2014

THE ENTIRE EXHIBIT NO. RBD-5C

IS DESIGNATED

CONFIDENTIAL PER PROTECTIVE ORDER IN UTC DOCKET UE-140762

Exhibit No. KGS-17T
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF KURT G. STRUNK

November 2014

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ATTACHED EXHIBITS

Q. Are you the same Kurt G. Strunk who previously submitted direct testimony in this case on behalf of Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp?

A. Yes, I am. My curriculum vitae, which more fully details my educational, consulting and testifying experience, is provided as Exhibit No. KGS-2, together with my direct testimony in this proceeding.

I. PURPOSE OF TESTIMONY AND SUMMARY OF OPINIONS

Q. Please explain the purpose of your testimony.

A. My testimony responds to the testimonies of Messrs. David C. Parcell, Stephen G. Hill, and Michael P. Gorman, who offer opinions on Pacific Power's cost of capital on behalf of the Staff of the Washington Utilities and Transportation Commission (Commission) Staff, Public Counsel, and Boise White Paper LLC (Boise), respectively. I also provide an update to my cost-of-capital analysis in order to present the Commission with a recommendation that reflects the most current conditions in the capital markets. Mr. Bruce N. Williams provides related responsive testimony on capital structure and credit metrics.

Q. Please summarize your rebuttal of the other cost of capital experts.

A. Based on a thorough review and analysis of these witnesses' testimony, I reach the following conclusions:

1. There is no dispute regarding the standards against which a fair rate of return should be judged.
2. A consensus exists among the experts on the objective of the exercise and the use of several well-accepted financial models, including the Discounted Cash

Flow (DCF) and Capital Asset Pricing Model (CAPM) from which to derive estimates of a fair return for Pacific Power.

3. While some dispute exists regarding the relevance of other models, the primary differences of opinion amongst the experts relate to the specifics of how the financial models are applied and which inputs are most appropriately relied upon.

4. In this regard, I find that Messrs. Parcell (for Staff), Hill (for Public Counsel) and Gorman (for Boise) rely upon invalid methods or inappropriate data sources or both, which causes them to understate the fair return estimate for Pacific Power. While I offer a detailed response in the body of my rebuttal testimony, I highlight here the key deficiencies in the analyses those witnesses present:

- The Staff and intervenor cost-of-capital witnesses mischaracterize the trends in allowed returns granted by state regulators across the country since January 2013. My rebuttal testimony corrects errors they have made when assessing the average allowed return and presents a proper evaluation of the trends in allowed returns for vertically integrated utilities comparable to Pacific Power.
- These witnesses present faulty analyses of capital structure. Each cost-of-capital witness for the other parties recommends a hypothetical capital structure. None provides any evidence that actually supports their recommendations in this respect.

- Further, they present invalid assessments of how a hypothetical capital structure changes the cost of equity capital. This leads Messrs. Parcell and Gorman to the incorrect and unsupportable conclusion that no leverage-based adjustment to return on equity (ROE) is necessary in the event the Commission elects to set rates using a hypothetical capital structure in place of the actual structure of the Company. Their testimonies on this subject ignore the elementary principle of finance that equity costs more as leverage increases because of the "financial risk" (a concept that is solidly part of the financial literature). Mr. Hill is correct to acknowledge that the ROE should be higher with a hypothetical capital structure, but his estimate of the increment is based on faulty assumptions.
- Mr. Gorman chooses to use a 10-year GDP growth forecast as a measure of long-term earnings growth for electric utilities. In using a U.S. government GDP growth forecast as a proxy for the expected long-term earnings growth rate for utilities (i.e., the expected growth that runs beyond five-year projections available from securities analysts), Mr. Gorman assumes those two growth rates should converge to each other. That assumption is incorrect, given the accepted empirical studies that document persistently higher total factor productivity (TFP) growth rates for the electric utility industry than for the economy as a whole. Given the established empirical relationship between economy-wide (*i.e.*, GDP) growth and relative TFP growth for the electricity industry, using the former as a proxy for expected growth in DCF cost of equity measures of the latter is invalid and

understates expected investor returns and the computed return on equity.

- Mr. Hill alleges that the forecast growth rates issued by securities analysts are biased upwards, and that consequently the cost of capital estimates derived therefrom are overstated. Yet he provides no evidence to support this claim. My rebuttal testimony demonstrates that there is no reason to expect systematic bias in the current market and regulatory context. Reputational concerns incentivize securities analysts to provide accurate forecasts. In addition, the Securities and Exchange Commission, in its oversight of the capital markets, took measures over ten years ago to address and resolve potential bias. The allegations of bias and "rosy forecasts" offered by Mr. Hill are disconnected from the current regulatory arrangements and the incentives associated with securities analyst forecasting.
- Finally, Messrs. Parcell, Hill, and Gorman present inaccurate analyses of the effects of their recommended capital structure and cost of capital on the Company's financial integrity and standard financial ratios. My rebuttal corrects these analyses and demonstrates that the returns recommended by these witnesses will lead to a weaker financial position for the Company.

Q. What is your updated recommendation for a fair ROE for Pacific Power?

A. As shown in Exhibit No. KGS-18, based on my updated analysis, I continue to recommend a ROE of 10.0 percent for the Company. The capital markets data I have reviewed and analyzed indicates that this return will allow the Company to preserve its financial integrity and attract capital on terms that are fair and reasonable to customers. Additionally, this return corresponds to the average return granted to other utilities so far this year and is therefore reasonably grounded in industry practice.

Q. Does this recommended return correspond to a specific equity ratio?

A. Yes, it corresponds to the Company's actual common equity ratio of 51.73 percent. Should the Commission elect to employ a hypothetical capital structure of 49.1 percent equity ratio, as proposed by Staff and intervenor witnesses, I recommend an upward adjustment of 28 basis points to reflect the increased risk to the Company's equity owners of the more highly-levered capital structure, as explained in my direct testimony. My rebuttal work papers contain an update to this analysis, showing the continued applicability of the 28-basis-point adjustment.

Q. How is the rest of your rebuttal testimony organized?

A. In Section II, I clarify the record with respect to the trends in allowed returns. In Section III, I address the characterization of capital market conditions presented by Messrs. Parcell, Hill and Gorman. In Section IV, I evaluate the claims of Messrs. Parcell, Hill and Gorman as they pertain to an appropriate capital structure for ratemaking purposes and the effects of capital structure on credit ratings and the cost of equity. In Section V, I address the choice of models to be used in establishing a fair rate of return and respond to these witnesses' claims about the choice of models. In Section VI, I address the appropriate inputs to the rate of return models. Section VII covers purported corroboration of the rate of return estimates made by Staff and intervenor witnesses, while Section VIII addresses the business and financial risks of the Company's regulated Washington operations relative to the proxy group utilities and the industry more broadly. In Section IX, I examine Pacific Power's financial integrity under the ROEs proposed by Staff and intervenor witnesses. Section X presents my updated analysis of the cost of equity capital.

II. CORRECTED ANALYSIS OF ALLOWED RETURNS

Q. What is the purpose of this section of your testimony?

A. Its purpose is to correct the record with regard to recent experience of the equity returns allowed by state regulatory authorities in the United States. The Staff and intervenor testimony characterizes the allowed returns as declining in 2014. However, a careful analysis of the 2014 allowed returns proves them to be stable, not declining.

Q. Please summarize the Staff and intervenor testimony as it pertains to allowed returns in other jurisdictions.

A. Messrs. Parcell, Hill and Gorman characterize recent experience of allowed/authorized returns as follows:

- Mr. Gorman contends that the correct average authorized return for 2013 is 9.8 percent. Mr. Gorman further argues that "authorized returns on equity are decreasing," and that the average authorized return for the first six months of 2014 is 9.72 percent.[1]
- Mr. Parcell also alleges that "commission-authorized returns on equity have declined over recent years."[2] He claims that the average allowed return for

[1] Responsive Testimony of Michael P. Gorman, Exhibit No. MPG-1T at 65:23-66:3.
[2] Testimony of David C. Parcell, Exhibit No. DCP-1T at 44:16-17.

2013 should be 9.8 percent and that the first quarter 2014 average should be 9.57 percent.[3]

- Mr. Hill contends that "the average allowed return for electric utilities in 2013 was 9.8%" and that the published Regulatory Research Associates (RRA) allowed return averages include cases that "were not based solely on the cost of capital."[4]

Q. What is wrong with these characterizations of allowed returns?

A. Messrs. Parcell, Hill, and Gorman remove the allowed returns for Virginia Power's generation facilities, claiming that they are not comparable, without removing other observations that would logically be excluded if a rigorous comparability screen were applied.

Q. Is it necessary to apply the screen proposed by these witnesses?

A. No. In my experience, investors tend to form expectations based on the published averages. In the market commentary and securities analysis I typically review in connection with the development of an ROE estimate, I often find reference to the published averages. In light of the weight the published averages are given by investment analysts, it is appropriate to use them as the proper benchmark for industry allowed returns.

Q. Could a rigorous screen be structured correctly to yield allowed returns that are directly comparable?

A. Yes. The allowed returns that comprise the 10.02 percent average for 2013 are

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[3] *Id*. at 44:13-14.
[4] Testimony of Stephen G. Hill, Exhibit No. SGH-1CT at 75:11-15.

returns that apply to a mix of business profiles within the electric utility industry. When taken as a group, they are appropriately reflective of investor expectations for the industry. However, as highlighted by the Virginia Power cases, some individual returns apply to generation-only businesses, others apply to distribution-only or transmission-only[5] businesses, while the balance of cases deal with integrated utilities directly comparable to Pacific Power. Because generation-only, transmission-only and distribution-only businesses carry risk profiles that differ from that of an integrated utility, a rigorous screen would logically exclude entities only operating in one segment of the supply chain and include only integrated utilities as directly comparable.

Q. What is the result of such a screen?

A. Table 1 below presents the averages for the calendar year 2013 and for the first ten months of 2014. In addition, I provide company-by-company allowed ROEs in Exhibit No. KGS-19.

TABLE 1
Average Allowed ROE for Integrated Utilities Comparable to Pacific Power

Time Period	Average Integrated Utility Allowed Return
Calendar Year 2013	**9.92 percent[6]**
January-October 2014	**9.92 percent**
Source: Regulatory Research Associates (RRA)	

[5] RRA tracks rates for transmission-only entities that are regulated by the Public Utilities Commission of Texas. *See* "Major Rate Case Decisions—Calendar 2013," *RRA Regulatory Focus* (Jan. 15, 2014).
[6] This average incorporates a 9.0 percent ROE for Maui Electric. However, in Docket No. 2011-0092, the Hawaii Public Utilities Commission recognizes that the cost of capital is higher and awards 9.0 percent as a penalty. *See* "Final Report—Maui Electric Company," *RRA Regulatory Focus* at 2 (June 18, 2013).

Table 1 confirms that average authorized returns have remained stable from 2013 to 2014. The claims of Messrs. Gorman and Parcell that authorized returns are declining is simply incorrect.

Q. Staff and intervenor witnesses opine that the Virginia Power returns are not comparable because they include incentives. Is it correct to exclude published returns that incorporate incentives?

A. No. Investor expectations depend on the total returns available to entities in the sector. A reasonable reading of *Hope* and *Bluefield* suggests that total returns are the correct focus and it is not how the return value was arrived at but whether at the end of the day it is just and reasonable. Following this reasoning, it is total achievable returns from comparable investments that should be considered when determining the returns available from comparable investments. It would be unreasonable to assume that returns available to comparable investments should be dissected and a portion of such returns ignored for ROE evaluation purposes.

Q. Is Virginia Power the only company whose published returns include incentives?

A. No. The published returns for other utilities may also include the effects of any incentives granted. For example, the allowed ROE published by RRA for Sierra Pacific Power Company in Docket 13-06002 includes certain generation-related incentives.[7]

Q. For electric utility rates overseen by the Federal Energy Regulatory Commission (FERC), have allowed returns on equity declined?

A. No. I have reviewed recent rate decisions by the FERC and the ROEs authorized for

[7] “Final Report—Sierra Pacific Power,” *RRA Regulatory Focus* at 2 (Mar. 11, 2014).

electric utility ratemaking purposes have remained stable and, in some instances, increased. On June 19, 2014, the FERC authorized a base ROE of 10.57 percent for the New England Transmission Owners,[8] which is comparable and, in several cases, above prior base ROE decisions over the past several years.

Q. Please summarize your rebuttal testimony on allowed returns.

A. Contrary to the statements of Staff and intervenor witnesses, the trend in allowed returns for electric utilities in the United States has not declined since January 2013. There is no evidence to suggest a substantial decrease in allowed returns, as contended by these witnesses. Rather, the average return for the first ten months of 2014 is equal to the 2013 average. In sum, I find the return on equity to be stable at approximately 10 percent for electric utility rates overseen by state commissions and above 10 percent for electric utility rates overseen by the FERC, before the addition of incentives.

III. ASSESSMENT OF CAPITAL MARKET CONDITIONS AND UTILITY STOCKS

Q. Mr. Gorman characterizes utility stocks as "low-risk securities."[9] Is this a fair characterization?

A. No. Over a century of practical experience with and scholarly study of financial markets demonstrates the statement to be false. Common equity, irrespective of the issuer, is widely acknowledged to be among the riskiest classes of securities available

[8] *See Coakley, Mass. Atty. Gen. v. Bangor Hydro-Elec. Co.*, Opinion No. 531, Docket No. EL11-66-001, 147 FERC ¶ 61,234 at 68 (June 19, 2014); *see also Coakley, Mass. Atty. Gen. v. Bangor Hydro-Elec. Co.*, Opinion No. 531-A, Docket No. EL11-66-001, 149 FERC ¶ 61,032 at 6-7 (June 19, 2014).
[9] Responsive Testimony of Michael P. Gorman, Exhibit No. MPG-1T at 4:1-4.

to investors.[10] While utilities' equities may be less sensitive to certain market news—after all, their beta is below unity—they are certainly not immune to large fluctuations in value and are by no means appropriately characterized as low-risk securities.

Q. Please describe any updates you have with respect to trends in capital market conditions that provide context for your rate-of-return recommendations.

A. In my direct testimony, I characterize current capital market conditions as unique from a historical perspective on the grounds that yields on long-term treasury bonds have been suppressed by the Federal Reserve's bond-buying program and remain at levels well below their historical average. The stock market continues to reflect these unique conditions. Although the Federal Reserve stopped its bond-buying program on October 29, 2014, it has indicated that it intends to keep short-term rates low. The effects of these recent changes on long-term Treasury yields have yet to be seen. Market forecasters anticipate a rise in yields, expecting that they will again be over four percent, as shown in Exhibit No. KGS-20.

Q. Please address volatility and the cost of equity for utility stocks.

A. Volatility is an important contributor to investment risk and to investor perceptions thereof. In my direct testimony, I note that utility stocks have been more volatile than broader stock indices since 2009. At the time of drafting this rebuttal testimony, uncertainty over the domestic economy, the Fed's continued intervention, and intervention of the European and Japanese Central Banks had led stock volatility indices to spike from under 15 percent to over 25 percent. The press has documented this trend of increased volatility. For example, an article in the Financial Times

[10] *See* Brealey, R., Myers, S., and Allen, F. *Principles of Corporate Finance*, 75, 161-162 (11th ed. 2014).

recently noted: "Investors are far from relaxed about the volatility spike, and understandably so."[11] This article considers several explanations for the increased volatility, including, for example, a reaction to reduced intervention by the Federal Reserve and a decreasing effectiveness of its policies to contain market volatility. I illustrate the trend of increased volatility in Exhibit No. KGS-21. Although the volatility index has fallen since the spike, this event reflects the great uncertainty in the markets and concerns over the potential for a correction. The volatility index remains at an increased level relative to where it was when I performed the analysis to support my direct testimony, indicating higher risk.

IV. CAPITAL STRUCTURE, CREDIT RATINGS AND ASSOCIATED EFFECTS ON THE COST OF EQUITY

Q. Do you agree with the recommendation of Messrs. Parcell, Hill and Gorman that the use of a hypothetical capital structure instead of the Company's actual capital structure is appropriate for ratemaking purposes?

A. No. In regulatory practice, it is most common to rely upon the utility's actual capital structure.[12] Regulators typically employ a hypothetical capital structure when the actual capital structure of a utility is unreasonable, abnormal or imprudent and thus falls outside the zone of reasonableness.[13] To merit the imputation of a hypothetical capital structure, a utility's actual capital structure would need to obstruct the achievement of well-established ratemaking objectives, which, as this Commission has articulated, involve balancing financial safety and cost minimization.[14]

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[11] *See* "Three possible explanations have differing market implications," *Financial Times* (Nov. 3, 2014).
[12] Goodman, Leonard Saul. *The Process of Ratemaking, Volume I*, 651-52 (1998).
[13] *Id.* at 655.
[14] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Order 05 ¶¶25-26 (Dec. 4, 2013).

The actual capital structure equity ratio proposed by the Company is not unreasonable, abnormal or imprudent. Rather, it is fully consistent with industry practice and does not obstruct the achievement of an appropriate balance between financial safety and cost minimization. No evidence put forth by the other cost-of-capital experts provides any defensible basis to reject the Company's actual capital structure. As I show below, the evidence of the other parties in this regard is based on misleading comparisons and incorrect data or assumptions.

Q. Is Mr. Gorman right to argue that a 49.1 percent equity ratio is consistent with industry practice?

A. No, that characterization fails to recognize important facts about ratemaking practice for electric utilities. While the 49.1 percent equity ratio is, of course, consistent with this Commission's decision in the Company's most recent rate case, which I am informed is currently in the judicial review process, it falls on the low end of the zone of reasonableness, as I explain below, and could not be implemented without corresponding adjustments to the costs of debt and equity.

The equity ratios authorized by public utility commissions across the United States establish the parameters that characterize industry practice. In fact, when considered in this context, a 49.1 percent equity ratio falls on the low end of equity ratios employed by other utilities for ratemaking purposes. I illustrate this in Table 2 below and in Exhibit No. KGS-22.

TABLE 2
Authorized Equity Ratios for Integrated Utilities Comparable to Pacific Power
January 2009 through October 2014

	Number of Cases	Percent of Cases
Cases with Equity Ratio Above 49.1	**105**	**66%**
Cases with Equity Ratio At or Below 49.1	**53**	**34%**
Source: Regulatory Research Associates		

Table 2 confirms that it is considerably more common in the regulated electric utility industry to employ an equity ratio that exceeds these witnesses' proposal of 49.1 percent than one at or below that level. The suggestion by Mr. Gorman that a common equity ratio of 49.1 percent is squarely consistent with industry practice is incorrect and misleading.

Q. Mr. Parcell suggests that the use of a 49.1 percent equity ratio is somehow justified by the lack of significant short-term debt in the Company's capital structure. Is this a reasonable public policy recommendation?

A. No. Mr. Parcell's suggestion is based upon misconceptions of the role of short-term debt and its effect on utilities' financial integrity in today's markets. Typically, the role of short-term debt is *not* to provide a consistent source of funding for long-lived assets like those carried on the books of public utilities. In addition, for many companies, short-term debt can be seasonal in nature, or can be used intermittently, with some periods showing balances and others showing no short-term debt. My review of the Company's short-term debt over time shows significant volatility in the quarter-end balances and does not suggest that it is a permanent source of funding for long-lived assets used to provide public utility services.

In addition, since today's capital markets are exhibiting extraordinary tendencies, one must consider whether it is appropriate public policy to include short-term debt *under the current market conditions*. The origin of the use of short-term debt as a component of the capital structure in ratemaking dates to the beginning of the 1980s. At that point, utilities began to propose *the inclusion* of short-term debt because it was necessary to do so to preserve their financial integrity in light of the extreme, sometimes negative, spreads observed between long-term and short-term debt instruments. A reversal of capital market conditions today warrants *the exclusion* of short-term debt from the capital structure for that same reason, *i.e.*, in order to maintain financial strength. The current spreads between the cost of long-term and short-term debt are higher than average, which is precisely the opposite of the conditions under which short-term debt was initially considered for inclusion in the capital structure.

Q. Is it standard, for ratemaking purposes, to include short-term debt in a utility's capital structure?

A. No. As Leonard Saul Goodman explains in *The Process of Ratemaking*, "[i]nclusion of short-term debt in the capital structure is the exception, rather than the rule."[15] The rule to which Professor Goodman refers is to account for only those sources of financing that are permanent.

Short-term debt is appropriately included only in exceptional circumstances such as those experienced in the 1980s. Additionally, commissions have in some cases allowed short-term debt under two additional circumstances: either when short-

[15] Goodman, Leonard Saul, *The Process of Ratemaking, Volume I*, 603 (1998).

term debt is a regular and continuing component of the Company's capital or when short-term debt is expected to be converted to long-term debt. These conditions are not present in this case. In sum, there is no basis to impute a level of short-term debt in the capital structure.

Q. How does the FERC use short-term debt?

A. The FERC specifies in its Uniform System of Accounts that short-term debt is to be used to determine an appropriate Allowance for Funds Used During Construction (AFUDC). Effectively, it assumes utilities will fund construction projects first with short-term debt and then with permanent sources of financing such as long-term debt, preferred stock and common equity.[16] FERC does not apply the short-term debt rate when determining the rate of return on assets that are in service and comprise a public utility's rate base.

Q. Did Mr. Gorman testify in support of the Company's approach to the use of short-term debt in the Company's 2013 rate case?

A. Yes. I understand that Mr. Gorman testified that many utilities do not rely on short-term debt and instead finance in a more conservative manner to lock in low interest rates and mitigate risk associated with refinancing short-term securities.[17] According to Mr. Gorman, the use of exclusively long-term debt is "generally consistent with a

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[16] *See* 18 CFR Part 101 - Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act.
[17] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Gorman, TR. 226:21-227:19 (Aug. 26, 2013).

conservative utility financing structure."[18] Therefore, Mr. Gorman did not propose the imputation of short-term debt.[19]

Q. Please address Mr. Gorman's statement that Standard & Poor's (S&P) no longer uses debt-to-capital ratios to determine a utility's financial risk profile.[20]

A. Mr. Gorman raises this issue in the context of evaluating whether the imputation of a 49.1 percent equity ratio would change the financial risk profile for this business, and would, as I state in my direct testimony, move it from a "Significant" to an "Aggressive" financial risk profile.

Although Mr. Gorman is technically correct to state that the guidance from S&P in late 2013 indicates a future focus on ratios other than debt-to-capital,[21] this new focus does not affect my conclusions with regards to the effect of a lower equity ratio on the financial risk profile. This is because the debt-to-capital ratio, long used by S&P, is but one indicator of leverage. The ratios that S&P now examines, including for example funds from operations (FFO)-to-debt and debt-to-earnings before interest, taxes, depreciation and amortization (EBITDA), are alternative indicators of leverage, which have traditionally been used in conjunction with the debt-to-capital ratio.

Ultimately the tool one uses to measure leverage is less important than the leverage itself. Just as an increase in leverage would manifest itself in the debt-to-

[18] *Id.*
[19] *Id.*
[20] Responsive Testimony of Michael P. Gorman, Exhibit No. MPG-1T at 18:6-8.
[21] The methodology for consideration of financial risk outlined in 2012 identified three financial benchmarks: funds from operations (FFO) to debt; debt to EBITDA; and debt to capital. In 2013, S&P updated its criteria for rating corporate industrial companies and utilities. To assist in determining the relative ranking of the financial risk of companies, S&P now only considers two core credit ratios: FFO to debt and debt to EBITDA. *See* "Corporate Methodology," *Standard & Poors Ratings Direct* at 30 (Nov. 19, 2013); *see also* "Methodology: Business Risk/Financial Risk Matrix Expanded," *Standard & Poors Ratings Direct* at 3-4 (Sep. 18, 2012).

capital ratio, it will also manifest itself in the FFO-to-debt ratio and in the debt-to-EBITDA ratio. Notably, S&P's benchmarks for FFO-to-debt and debt-to-EBITDA did not change in November 2013. Hence, there is no reason to believe that the increase in leverage implied by a 49.1 percent hypothetical equity ratio would not trigger a change in the financial risk profile for the business, consistent with the guidelines that have long governed the S&P rating process.

Q. Please comment on Mr. Hill's approach to assessing the premium on the cost of equity that would accompany the use of a 49.1 percent equity ratio.

A. Mr. Hill computes an adder of eight basis points to be applied if the Commission imposes a hypothetical equity ratio of 49.1 percent in place of the Company's actual capital structure. The method Mr. Hill uses is nearly identical to the one I relied upon to determine my recommended adjustment of 28 basis points, the only conceptual difference being the fact that Mr. Hill assumes PacifiCorp's regulated operations in Washington would carry a higher market-to-book ratio. This is an assumption I disagree with and that Mr. Hill has not supported.

Q. Do you agree with Messrs. Parcell and Gorman that no adjustment is needed on the grounds that the Proxy Group purportedly already has an equivalent or even lower equity ratio?

A. No. While I agree with these witnesses that the book value debt-to-capital ratio is a *prima facie* indicator of the level of financial risk employed, their analysis of the Proxy Group does not encompass sufficient detail from which to draw reliable conclusions. One problem is that these witnesses rely upon capital structure measures that do not necessarily convey the true financial risk that the proxy group and other industry benchmarks carry. Specifically, they elect to analyze debt before adjustments are made to impute debt from long-term obligations such as the capacity payments under power purchase agreements and other debt-like instruments. These adjustments are critical to assessing a utility's true financial position. By ignoring them, these witnesses do not make a proper comparison.

In contrast, when I sought to evaluate financial risk, I found that PacifiCorp shows reasonable comparability to the Proxy Group companies when more detailed measures than the *prima facie* book value debt-to-capital ratio are considered. The detailed measures do not support the claim that PacifiCorp carries a lower financial risk profile than the Proxy Group. Specifically, I examined the following metrics for PacifiCorp and the Proxy Group companies to arrive at this conclusion:

- FFO coverage, from S&P. This is an important financial risk ratio considered by S&P when assessing financial risk in the ratings process and is also a key metric used by Moody's and Fitch. The Company's FFO coverage ratio falls reasonably in the range of that observed for the proxy group.

- Authorized equity ratios. I compared the Company's equity ratio of 51.73 percent to those for proxy company utilities during 2013 and 2014. The Company's proposed equity ratio falls reasonably within the range of authorized equity ratios.

Furthermore, my proxy group screening criteria consider only companies that carry comparable credit ratings and are comparable in size. Although these initial screens are less granular than the above comparisons, they also help to assure general comparability as between the Company and the Proxy Group.

In sum, the evidence put forth by the other cost of capital experts is based on one *prima facie* indicator alone. More complete and more relevant data analysis indicates that the Proxy Group companies do not carry riskier financial profiles than

PacifiCorp. In this context, *it is* necessary to account for higher costs of equity capital when imputing for ratemaking purposes a capital structure with more financial risk than PacifiCorp and the Proxy Group companies.

V. CHOICE OF MODELS

Yield-Plus-Growth

Q. Please comment on Mr. Gorman's statement that the Yield-Plus-Growth model "is not a methodology that is appropriate for estimating a fair return for PacifiCorp in this proceeding."[22]

A. This statement is not correct. It is well established that the return expectations for the industry as a whole influence investors' expectations for individual companies within the industry. Often, when it is difficult to assess a company-specific or project-specific cost of capital, practitioners rely upon the industry-average cost of capital in its place. This confirms the relevance of industry return expectations.[23] The record in this proceeding would be wanting if estimates of expected industry returns were not presented to the Commission.

Comparable Earnings

Q. Please comment on the testimony of Messrs. Parcell, Hill and Gorman as it concerns the use of the Comparable Earnings model.

A. No consensus exists among these experts on the applicability of the Comparable Earnings model. Mr. Gorman contends that Comparable Earnings is not an appropriate method for estimating ROE. Mr. Hill makes a similar claim. However, their testimony in this regard is unsupported and contradicts the well-established

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[22] Responsive Testimony of Michael P. Gorman, Exhibit No. MPG-1T at 65:1-3.
[23] In fact, reliance on industry return expectations is similar in nature to reliance on a proxy group.

principle in applied finance that past returns influence investors' forward-looking expectations. To claim, as Mr. Gorman does, that the comparable earnings model is flawed or irrelevant inappropriately ignores a key factor of influence for rate-of-return expectations as well as the specific guidance of the Supreme Court's *Hope* decision, where the Court makes specific reference to the need for an analysis of comparable earnings.

I note that Staff's cost-of-capital expert, Mr. Parcell, lauds the use of the Comparable Earnings (CE) model: "The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, it provides a direct measure of the fair return, since it translates into practice the competitive principle upon which regulation rests."[24]

I understand that the Commission has also previously relied on the Comparable Earnings model, after first observing that it "appreciates and values a variety of perspectives and analytic results because these serve to better inform the judgment it must exercise than would a single model, or a single expert's opinion."[25]

Modified Earnings-Price Ratio

Q. Please comment on the Modified Earnings-Price Ratio model advanced by Mr. Hill.

A. Mr. Hill employs the modified earning-price ratio (MEPR) analysis and states it can be useful in a corroborative sense. It is well known that the Earnings-Price ratio understates the cost of capital when market-to-book ratios exceed unity. Although

[24] Testimony of David C. Parcell, Exhibit No. DCP-1T at 34:1-4.
[25] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy Inc.*, Dockets UE-090704 and UG-090705, Order 11 ¶¶ 292-300 (Apr. 2, 2010).

Mr. Hill modifies the approach, his recommendation to use the midpoint of the bounds he identifies is arbitrary. The method remains inferior to other approaches and is not a good source of corroboration.[26]

Importantly, it is not a model that is used by investors or relied upon in regulatory practice. It has been my experience that investors do not rely upon the earnings-price approach or the modified earnings-price approach to assess the cost of capital. In regulatory practice, Mr. Hill cites the generic financing proceeding Order No. 420, issued by the FERC in 1985, as support for this model. However, the FERC has adopted it neither as a method for estimating the ROE nor as a means of corroborating ROE estimates.

Market-to-Book

Q. Please comment on the Market-to-Book model advanced by Mr. Hill.

A. In my experience, analysis of market-to-book ratios in the context of cost of capital determination often involves the use of econometrics. Mr. Hill's use of them does not employ econometric techniques. His analysis, as presented, provides little additional information and does not properly serve as a corroboration of the ROE estimates presented by Mr. Hill. Again, this is an approach that has little use by investors and by regulators in their practical assessments of utility costs of capital.

[26] *See* Kolbe, A.L., Read, J.A. & Hall, G.R. *The Cost of Capital—Estimating the Rate of Return for Public Utilities*, 55-57 (1984).

VI. MODEL INPUTS

Equity Risk Premium

Q. Does Mr. Parcell's claim that you should not use current interest rates to measure the equity risk premium have merit?

A. No. Mr. Parcell conflates two separate and distinct issues: (1) whether the historical equity risk premium applies in today's marketplace; and (2) how to estimate and use a forward-looking risk premium today. He attempts to tie my statement that the historical risk premium is inapplicable today to the question of how to estimate and use a forward-looking risk premium. Yet these have little to do with one another. My analysis of the Market Risk Premium is consistent as it assesses the premium based on the current level of rates and applies the premium to those rates. It would be inconsistent to do it in any other fashion.

Q. Please address Mr. Gorman's claim that the Equity Risk Premium you rely upon is not reasonable because it is based on too high an expectation of growth.[27]

A. To support this claim, Mr. Gorman compares the projected growth of corporate earnings to the projected US GDP growth. Mr. Gorman premises his criticism on the statement "It is simply not a rational expectation to believe that, for an extended period of time, the growth rate of companies will exceed the growth of the overall economy in which they sell their goods and services."[28]

Mr. Gorman's analysis is flawed for several reasons. First, it fails to recognize that part of the growth in these companies derives from activities abroad.

[27] Responsive Testimony of Michael P. Gorman, Exhibit No. MPG-1T at 57:3-6.
[28] *Id.* at 57:13-16.

He assumes erroneously that these companies source their growth exclusively from transactions in the US economy.

Second, historical stock market performance shows that Mr. Gorman's contention is wrong. The capital market data indicate an overall market return of 11.95 percent. As I show in Exhibit No. KGS-22, this return is consistent with actual returns achieved by investors in the S&P 500 Index, which is the index from which I develop the market return. Hence, the return assumption I rely upon—a forward-looking figure implied by equity markets pricing—is also well calibrated to historical conditions in those same markets. Mr. Gorman's criticisms are based on incorrect assumptions and data.

Q. Do you agree with Mr. Hill's and Mr. Parcell's equity risk premium assumptions of 6.0 percent and 5.85 percent, respectively?

A. No. These assumptions do not make sense and are disconnected from current capital market conditions. As I explain in my direct testimony, the spread between the risk-free rate and the required returns for holding equities has broadened as the Federal Reserve System has aggressively acted to keep long-term interest rates at record lows and stimulate the economy. Both Mr. Parcell and Mr. Hill rely on historical estimates that do not capture the uniqueness of current capital market conditions. Creating further problems, Mr. Parcell arrives at his estimate by blending in the geometric mean of historical equity return spreads with arithmetic mean estimates. As I demonstrate below, the use of geometric means for forward-looking cost-of-capital analysis is invalid. These flaws render their equity risk premium assumptions unreliable.

Q. Mr. Hill substitutes the equity risk premium used in Australia by the Australian Energy Regulator in your CAPM model.[29] Is Mr. Hill's substitution reasonable?

A. No. The specific value used by the Australian Energy Regulator has no direct application to the cost of equity for Pacific Power, as Mr. Hill suggests it does. Several factors make this so. First, the Australian Energy Regulator establishes the equity risk premium for the Australian stock market, not the stock market in the United States. In addition, the equity risk premium used is calculated with reference to a 10-year bond yield, not a 30-year bond yield. In the context of an upward-sloping yield curve, this will produce an equity risk premium that is too low and cannot be applied to a 30-year treasury yield. Mr. Hill erroneously applies it to a 30-year treasury yield. For these reasons, Mr. Hill's comparisons are not relevant.

Proxy Group Selection

Q. Please comment on the proxy group selection of Messrs. Parcell, Hill and Gorman.

A. Mr. Gorman adopts the proxy group that I employed in my direct testimony, although he removes Avista, Duke, Pepco Holdings and Wisconsin Energy due to "significant merger and acquisition activity." I had not excluded Duke, Pepco Holdings and Wisconsin Energy as that their merger announcements occurred after my testimony was filed. As described in Section X, I also exclude the cost-of-capital parameters for these three companies when I refresh the analysis for my Proxy Group. On balance, the differences as between Mr. Gorman's proxy group and my Proxy Group are not significant.

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[29] Testimony of Stephen G. Hill, Exhibit No. SGH-1CT at 72:3-10.

Similarly, Mr. Parcell also adopts the Proxy Group from my direct testimony, although he also determines himself another proxy group of seven companies. Given the large pool of publicly-traded, electric utility holding companies, I find his seven-company proxy group to be unnecessarily small in number and not sufficiently diverse. The law of large numbers dictates that, all else equal, more companies yield greater confidence in the results. It is also my understanding that the Commission has previously criticized a seven company proxy group for having "questionable statistical reliability."[30]

Mr. Hill, for his part, uses very strict criteria to arrive at a proxy group of 13 companies. He uses approximately one quarter of the entities considered by Value Line to be electric utilities. Like that of Mr. Parcell, Mr. Hill's proxy group is less likely to provide a robust result due to its small size than a larger proxy group.

Dividend Yield Adjustment

Q. Please explain the multiplier you used to convert the historical dividend yield to a forward-looking dividend yield for your DCF model.

A. I rely on a full year of historical dividends to calculate the dividend yield. When converting that to a forward-looking dividend yield, I added one year of growth. This is the correct method to use when one relies on a full year of historical dividend data. In effect, each quarter of dividends is brought forward by a year in order to have a full year of expected future dividends.

Q. Does Mr. Hill take issue with this method?

A. Yes. He argues that I should have only applied half a year's growth. This would

[30] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 78 (Mar. 25, 2011).

have been appropriate had I used six months of dividends, but with one year of historical dividends, the right growth factor is a full year of growth.

Q. Is Mr. Hill right to criticize your use of a half a year's growth in FERC proceedings?

A. No. Mr. Hill has no basis for this criticism. Even where the application of a full year's growth is the proper approach,[31] as a practical matter, there is virtually no room in a FERC proceeding to implement any alternative to the use of half a year's growth. The use of half a year's growth for the FERC DCF model is prescribed by federal case precedent[32] that requires a very strict adherence to FERC's stated methodology and stated sources for data.

Analyst Growth Forecasts

Q. Mr. Hill claims that "sell-side institutional analysts that are polled by IBES, Zacks, and similar services offer relatively 'rosy' expectations for the stock they follow. Simply put, some analysts overstate growth expectations to make the stocks they want to sell look more attractive."[33] Please comment.

A. Mr. Hill appears to be describing the conflicts of interest that were identified by the Securities and Exchange Commission (SEC) and were addressed in a series of reforms in 2003, although he fails to distinguish between questions of whether analysts' ratings ("Buy," "Sell" and the like) are optimistic and questions about the integrity of analyst's earnings forecasts. In any event, the SEC's reforms include Regulation AC and the Global Analyst Research Settlements. Regulation AC

[31] *See, e.g.*, "Four Common Errors in Applying the DCF Model in Utility Rate Cases," NERA Working Paper, (Feb. 1, 1992).
[32] *See Southern Cal. Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070 at 17 (July 26, 2000).
[33] Testimony of Stephen G. Hill, Exhibit No. SGH-1CT at 44:8-11.

requires securities analysts to make certain certifications regarding potential conflicts; it is designed to promote the integrity of analyst reporting. In addition, the Global Analyst Research Settlements required investment banks with research departments to make structural reforms that separate research and investment banking activities. Under the settlements, "analyst's compensation will be based in significant part on the quality and accuracy of the analyst's research."[34] Since the reforms, several academic papers have documented improvement in the integrity of analyst guidance.[35]

Q. Did Mr. Gorman rely on analyst growth rates in his constant growth DCF model?

A. Yes. Mr. Gorman relies on analyst growth rates for his constant growth model on the basis that, "As predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data."[36]

Measure of Central Tendency

Q. Mr. Gorman suggests that your DCF analysis should have been based upon the median, not the mean.[37] Is he correct?

A. No. His opinion in this regard is based upon his subjective judgment. The mean and the median both provide useful information, but the information conveyed by each measure is different. Mr. Gorman believes that certain individual company estimates are outliers (both high and low) and should be excluded from the central tendency analysis. Yet, he has no rational way to differentiate between outliers and data that

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[34] *See SEC Fact Sheet on Global Analyst Research Settlements*, available online at http://www.sec.gov/news/speech/factsheet.htm (accessed Nov. 12, 2014).
[35] *See, e.g.*, "Measure for Measure: The Relation between Forecast Accuracy and Recommendation Profitability of Analysts," *Journal of Accounting Research*, Vol. 45, No. 3 at 604 (June 2007).
[36] Responsive Testimony of Michael P. Gorman, Exhibit No. MPG-1T at 25:3-4.
[37] *Id.* at 55:18-23.

truly can inform the Commission about the central tendency and the ROE. To ignore these estimates would be to limit unnecessarily and arbitrarily the data upon which the estimates are based. The end result of Mr. Gorman's use of the median is to lower the DCF-based estimate – falling a full 30 basis points below Mr. Gorman's own recommendation. This subjective and arbitrary choice of central tendency measure is unwarranted. Instead, the DCF results should be viewed, as I have viewed them, as a portfolio with an average expected return.

Screening Criteria

Q. Mr. Hill suggests that your screening methods somehow trigger adverse selection and bias your DCF results. Please respond.

A. Mr. Hill believes that excluding utilities with negative earnings growth forecasts or dividend cuts somehow assures an overstated ROE.[38] However, Mr. Hill is wrong to believe this and to make this suggestion. Mr. Hill himself excludes companies that have had dividend cuts. As for growth forecasts, one reason I exclude utilities with negative earnings growth forecasts is that those companies typically have idiosyncratic issues that cause the forecasts to be negative. It would be inappropriate to assume that those idiosyncratic issues should be incorporated into a rate-of-return estimate for a proxy group. A second reason I exclude utilities with negative earnings growth forecasts is that incorporating them is not tractable. Importantly, my approach is commonly used in regulatory practice, and for good reason.

[38] *See* Testimony of Stephen G. Hill, Exhibit No. SGH-1CT at 60:13-18.

Geometric versus Arithmetic Mean

Q. On various occasions, Messrs. Parcell, Hill and Gorman rely upon the geometric mean of historical values in their ROE analyses. Is this defensible?

A. No. Scholarly inquiry into whether the geometric or arithmetic mean is appropriate indicates a general preference for the arithmetic mean in the context of forward-looking rate-of-return estimation.[39] Roger Morin explains in his treatise, *Regulatory Finance*: "One major issue relating to the use of realized returns is whether to use the ordinary average (arithmetic mean) or the geometric mean return. Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital."[40]

GDP Forecasts as Inputs to the DCF Model and Caps on Earnings Growth

Q. Please describe the purpose of this section of your testimony.

A. In this section, I address the proposed use of GDP forecasts as an input to the DCF model, an approach taken by Mr. Gorman. I further address Mr. Gorman's statement that "Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services" and his contention that growth rates above GDP are unsustainable and should be removed from the DCF analysis.

Q. Has the Washington Commission expressed reservations about the use of GDP growth rates for the DCF model in previous cases?

A. Yes. In the last two Pacific Power rate orders, the Commission rejected the Company's use of a GDP growth rate informed by historical GDP data in the DCF model. The Commission did indicate that it might consider short-term, forward-looking GDP estimates as a DCF growth rate.

[39] *See, e.g.*, Brealey, R., Myers, S., and Allen, F. *Principles of Corporate Finance*, 162-163 (11th ed. 2014).
[40] Morin, Roger A. *Regulatory Finance – Utilities' Cost of Capital*, 275 (1994).

Q. Is it correct to use short-term GDP forecasts as a proxy for the long-term earnings growth of electric utilities?

A. No. Use of short-term gross domestic product (GDP) growth forecasts, a national income accounting statistic, as a proxy for the expected long-term earnings growth rate of utilities has no theoretical basis. There is significant theoretical and empirical support for the notion that utilities productivity (and in turn their earnings) grow at different rates than that of the economy as a whole. A Total Factor Productivity (TFP) Study can identify the differential TFP growth rates for various segments of economic activity as compared to the economy as a whole.[41] Given the theoretical relationship between GDP growth and relative TFP growth, using the former as a proxy for expected profitability of the latter is invalid and should not be an input to determine the fair rate of return.

Q. Does Mr. Gorman's approach, to exclude forecast earnings growth rates that exceed the GDP growth rate, make sense?

A. No, Mr. Gorman's approach is incorrect. NERA's empirical studies, relying on FERC Form 1 data, show that the total factor productivity growth of combination electric/gas utilities during the period 1972 to 2009 averaged 0.96 percent. Over the same period, the total factor productivity of the US economy grew at a slower pace of 0.91 percent.[42] In other words, utilities were more productive than the economy as a whole by more than 5 percent. These results, and those of similar TFP studies,

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[41] *See*, *e.g.*, *Re Rate Regulation Initiative*, Alberta Utilities Commission, Proceeding ID No. 566, NERA Report: "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative" (Dec. 30, 2010). *See also Re Central Maine Power Co. Request for New Alternative Rate Plan*, Testimony of Mark N. Lowry, Maine Public Service Commission, Docket No. 2007-215, (May 1, 2007).

[42] *Re Rate Regulation Initiative*, Alberta Utilities Commission, Proceeding ID No. 566, NERA Report: "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative" at 19 (Dec. 30, 2010).

consistently show that, contrary to Mr. Gorman's statements, utilities can sustain—and, indeed, have sustained— growth rates that exceed the economy in which they sell services. As such, it is not appropriate or logical to exclude forecast utility earnings growth rates that are above the GDP growth forecast.

Q. Please summarize your conclusions on the use of GDP growth forecasts in ROE estimation in Washington.

A. Short-term forecasts of GDP growth, a national income statistic, are not necessarily tied in any way to the long-term growth of individual utilities. As such, it is not an appropriate input for the DCF model and should not serve as a cap on sustainable growth. Empirical studies show that utilities can grow at rates that exceed the growth in the economy overall. Hence, insofar as Mr. Gorman relies upon it, such reliance will lead to an underestimate of the ROE.

Company Selection for Yield-Plus-Growth Model

Q. Mr. Hill criticizes your yield-plus-growth model on the grounds that the "yield" and "growth" inputs rely on distinct sets of companies. Please comment on this criticism.

A. Mr. Hill is factually correct that the Zacks growth forecast considers additional companies to Value Line. Mr Hill is incorrect as to the implications of this for ROE estimation. Mr. Hill's conclusions are incorrect for at least two reasons. The first is that overlap exists as between the companies covered by Zacks growth forecast and the Value Line dividend yield assessment. Zacks includes 47 of 49 electric utility companies followed by Value Line. Second, both the Zacks growth forecast and the Value Line dividend yield assessment serve to influence investor expectations for the electric utilities industry generally. It is thus appropriate to rely on these metrics to evaluate investor expectations. It is not uncommon for components of the broad yield-plus-growth model calculation to cover slightly different sets of companies.

Q. Mr. Hill presents an alternative calculation whereby he uses the Yahoo Finance industry growth forecast and the Value Line dividend yield. Please comment on this calculation.

A. Mr. Hill claims that his alternative calculation relies on the same set of companies, but his statement in this regard is incorrect. Mr Hill relies upon the dividend yield data for 49 electric utilities covered by Value Line and then relies upon the growth forecast for 278 companies covered by Yahoo Finance. His calculation does not resolve the problem that he attributes to my analysis.

Specification of the Risk Premium Model

Q. Mr. Hill takes issue with your finding that the expected risk premium for utility stocks varies inversely with long-term treasury yields. Please respond.

A. Mr. Hill's claims in this regard are without merit. He characterizes the relationship as "counter-intuitive." However, the finding is quite intuitive when viewed in the context of investor sentiment. When investors perceive large risks associated with holding risky assets, they flock to securities like long-term treasuries and other high-grade bonds. This drives up prices and drives down yields on such securities. The spread between the cost of holding treasury and other high-grade bonds and the cost of holding riskier assets expands. History demonstrates that the premium for holding risky assets has expanded during times when investors have pursued a flight to quality. While Mr. Hill may believe that this investor behavior is counter-intuitive, it represents a trend in the capital markets. I cite in my direct testimony several scholarly articles that arrive at the same finding with respect to this relationship.

VII. CORROBORATION OF COST OF EQUITY ESTIMATES

Use of Pension Fund Returns

Q. Does Mr. Hill use expected pension fund returns as an alleged corroboration of his estimated ROE?

A. Yes. Mr. Hill relies upon the expected returns on certain index fund investments as a point of comparison for his ROE recommendation for Pacific Power. These indices are not utility indices and do not provide a direct comparison. Insofar as they might be used to estimate a utility ROE—for example, by applying a utility beta to the risk premium implied by the expected market return—the results demonstrate that this benchmark falls outside of the zone of reasonableness. The benchmark falls closer to the cost of debt than to the cost of equity for an electric utility and thus is not realistic. See Confidential Exhibit No. KGS-23C.

Q. Does the use of expected pension fund returns have any basis in regulatory practice?

A. No. I am unaware of any regulatory authority that has relied upon this type of evidence when determining a just and reasonable rate of return for public utilities.

Allowed Returns

Q. Can ROEs allowed by other state regulators serve to corroborate the estimated ROE?

A. Yes. State regulators make their findings as to a reasonable ROE based on the evidence presented to them in rate cases. Their findings are thus based on a careful review of capital market data and the processing of such data using models like the DCF and CAPM, among others. As such, allowed returns provide an important source of corroboration for the ROE estimates advanced by the parties. Furthermore, as I explain in my direct testimony, the returns allowed by regulators help to shape investor expectations about the returns that their investments in the electric utilities sector will deliver.

Q. How do the allowed returns compare to the ROE you recommend and those recommended by the other cost-of-capital experts?

A. As shown in Exhibit No. KGS-19, the allowed returns demonstrate that the ROE of 10 percent that I recommend for establishing Pacific Power's electric rates in Washington falls squarely within the zone of reasonableness. That return level is consistent with the return levels granted by state regulators and below the returns granted by FERC. In contrast, the experience from other regulatory proceedings does not support the ROE recommendations of Mr. Hill (8.9 percent), Mr. Parcell (9.0 percent) and Mr. Gorman (9.3 percent). These ROE recommendations fall close to 60 to 100 basis points below the average award issued by state commissions in forty-two rate cases during 2013 or 2014 and close to 300 basis points below the returns granted to certain transmission operators by the FERC. This underscores that my analysis provides a more reasonable view of the required return on equity for investments in utilities like Pacific Power.

VIII. BUSINESS AND FINANCIAL RISKS RELATIVE TO THE PROXY GROUP

Q. What is the purpose of this section of your testimony?

A. In this section, I summarize my response to Messrs. Parcell, Hill and Gorman with respect to PacifiCorp's business and financial risk relative to the Proxy Group and industry. These witnesses allege that PacifiCorp, and by implication its regulated operations in Washington, is less risky than the Proxy Group.

Q. What are the basic types of business risks applicable to electric utilities?

A. My direct testimony summarizes the risks faced by Companies engaged in the generation, distribution and sale of electric power at retail. Since I filed my direct testimony, the Environmental Protection Agency (EPA) released, on June 2, 2014, its Clean Power Plan Proposal, which seeks to regulate greenhouse gas emissions from existing generation plants under Section 111(d) of the Clean Air Act. This plan, as proposed, will reduce CO_2 emissions to 30 percent below 2005 levels by 2030. It will require a shift in the fuel mix so that coal-fired generation has an increasingly less important role in supplying energy to regional electric markets. The EPA anticipates that increased natural gas generation, renewables and energy efficiency will fill the void left by reductions in base load coal-fired generation.

Q. How does the Clean Power Plan affect the risks to investors in the utilities sector?

A. While the EPA has not yet issued its final rule, and is not scheduled to do so until June 2015, investor perceptions of this new rule are that it will increase risks for utilities that are heavily dependent on coal-fired generation, particularly those that do not have or are unable to obtain explicit recovery mechanisms for asset retirements and incremental generation dispatch costs (*e.g.*, in the absence of a fuel adjustment clause). In this sense, it underscores the need for a regulatory framework that is flexible and makes a priority of preserving the financial strength of incumbent utilities which need that strength to be able to facilitate the transition to cleaner fuels. Financial strength is essential if incumbent utilities are to continue to contract with independent power producers who rely on the credit of the offtaker to secure financing. It is essential to enable the construction of new utility-owned facilities. For its part, S&P noted at the time the Clean Power Plan was released that: "For some regulated utilities, credit quality could suffer marginally if they are unable to fully recover investments and incremental operating costs."[43] Equity analysts share the same view of risks as they could materialize for equity investors. For example, Barclays notes in its Power & Utilities Energy Conference Review: "<u>The negatives included uncertainty around 111(d)</u>."[44] Barclays goes on to summarize investor sentiment: "<u>Key areas of uncertainty were 111(d)</u>, weak regulated sales in part due to energy efficiency and the impact of elections on regulation particularly in Florida and Massachusetts."[45]

Q. Have you compared the share of coal-fired generation within the PacifiCorp generation fleet to the typical share for the industry and for the Proxy Group companies?

A. Yes. Exhibit No. KGS-25 presents this comparison. This exhibit demonstrates that PacifiCorp has more coal-fired generation than the average Rebuttal Proxy Group

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[43] "S&P's First Take On The EPA's Proposed CO2 Rules For Power Generators," *Standard & Poors Ratings Direct* at 5 (June 3, 2014).
[44] "Energy Conference Review," *Barclays Power & Utilities* at 1 (Sept. 10, 2014) (emphasis added).
[45] *Id.* at 4 (emphasis added).

company or the average company in the industry. As I illustrate in Table 3 below, this is true when measured both on a capacity basis and on an energy basis.

Table 3
Comparison of Coal-fired Generation Capacity and Energy Production

	Percent Coal Based on Operating Capacity (MW)	**Percent Coal Net Generation (MWh)**
PacifiCorp	60%	76%
Rebuttal Proxy Group	36%	40%
Industry	28%	39%
Source: SNL Energy.		

Q. Please summarize your evaluation of the relative risks of proxy group companies as compared to Pacific Power.

A. As I found in my direct testimony, they are generally comparable in that they share the business risks that are typical of public utilities, as described in my direct testimony. In this regard, Pacific Power is comparable to the Proxy Group and to the industry more broadly. Furthermore, key financial metrics for the Company fall reasonably within the range of those observed for the proxy group companies.

Against this, two important risks stand out as affecting negatively investor perceptions of PacifiCorp. These are: the 111(d) risk I describe above and regulatory risk, particularly in Washington. As I mentioned in my direct testimony, Pacific Power faces certain challenges in Washington following the decision in its 2013 Washington rate case, Docket UE-130043, the outcome of which is currently undergoing judicial review. In his rebuttal testimony, Mr. Williams cites to recent rating agency comments expressing concerns about the Company's regulatory support in Washington.

IX. FINANCIAL INTEGRITY ANALYSIS

Q. Please describe the financial integrity analysis performed by Messrs. Parcell, Hill and Gorman.

A. These witnesses attempt to analyze the effects of their recommendations on the Company's financial integrity. These witnesses purport to demonstrate that their recommended 49.1 percent equity ratio coupled with returns on equity of 8.9 percent (Mr. Hill), 9.0 percent (Mr. Parcell) or 9.3 percent (Mr. Gorman) will not be harmful to the Company's financial health.

Q. Please address Mr. Gorman's analysis of the Company's credit metrics using his recommended return of 9.0 percent.

A. Mr. Gorman's forecast credit metrics do not make sense in light of the PacifiCorp's current financial ratios. The Company's FFO/Debt ratio is currently 20.49x, as of year-end 2013. Mr. Gorman's suggestion that dropping the ROE by 20 basis points from the currently allowed level of 9.5 percent to 9.3 percent would improve its ratios is simply not credible. Mr. Gorman appears only able to infer such ratios by ignoring part of the debt imputed by investors, a point discussed in more detail by Mr. Williams. Dropping the ROE to the level proposed by Mr. Gorman could not raise the Company's credit metrics, as he claims.

Q. You note that Mr. Gorman excludes certain obligations that investors treat as debt. Is this appropriate?

A. No. It is not appropriate to exclude obligations that investors take into account when making an assessment of utility risk and financial strength. Doing so results in a biased analysis that does not reflect the true financial position of the Company.

Q. Does Mr. Gorman's purported rationale for excluding them – *i.e.*, that these obligations are controllable by management or not related to the cost of service – have any merit?

A. No, it does not. Whether these obligations are controllable by management does not affect whether they should be considered as part of the Company's debt and taken into account when assessing financial integrity. The fact that Mr. Gorman obtains the level of imputed debt – which he then ignores – from a source that investors routinely rely on confirms that they are viewed as debt by investors. As such, it is illogical and inappropriate to exclude these obligations from the analysis of financial integrity. Any assessment of whether a given ROE will allow the Company to maintain its credit and preserve its financial integrity, as required by the *Hope* decision, must take into account all obligations that the Company faces.

Moreover, Mr. Gorman errs in characterizing these obligations as unrelated to the cost of service and has provided no support for such a characterization. Pacific Power's operations in Washington exist to provide reliable electric service to Washington consumers at reasonable, cost-based rates. The post-retirement obligations for Pacific Power employees derive from its duties to serve the public. They are not unrelated to the cost of service, as alleged by Mr. Gorman.

Q. Please address the analysis of the Company's credit metrics made by Messrs. Parcell and Hill using their recommended ROEs of 9.0 percent and 8.9 percent respectively.

A. Each witness relies on a single credit metric to evaluate the Company's financial integrity under his recommended ROE: pre-tax interest coverage. Each performs an elementary calculation of this ratio. Mr. Parcell shows his in Exhibit No. DCP-15, while Mr. Hill offers his as Exhibit No. SGH-15. Mr. Parcell acknowledges that this metric is no longer used by S&P for risk rankings, yet he goes ahead and compares the resulting coverage ratio to the S&P benchmarks.

Importantly, neither Mr. Parcell nor Mr. Hill has taken into account imputed debt, which is an important factor considered by investors when assessing financial strength and credit quality. And, as pointed out by Mr. Williams, in their credit metrics analysis, none of the parties take into consideration the impact of the significant adjustments that they are proposing in this case or attrition, which I understand to be a real issue for the Company in Washington. As a result, these witnesses present ratios that are biased and suggest higher credit metrics and a stronger financial position than actually applies to the Company.

Interestingly, Mr. Hill's shows a pre-tax coverage ratio that corresponds to a BBB-ratings bracket on Mr. Parcell's benchmark ratios. Hence, Mr. Hill's analysis suggests financials that correspond to a lower credit rating than the Company currently carries with S&P. If adopted, these witnesses recommendations would not yield the "credit-sustaining revenue"[46] that is necessary for the proper discharge of the Company's duties.

X. UPDATED COST OF EQUITY ANALYSIS

Q. Please describe your approach to updating the cost-of-capital models and estimate.

A. I applied the same criteria and same models that were used to develop my recommendation for the Company's direct filing. The update performed simply refreshes the analyses with data through early November of this year.

Q. Did you update the proxy group in connection with the preparation of this rebuttal testimony?

A. Yes, it was necessary to update the proxy group in order to assure that that all companies continue to pass the screens, and that consequently the models continue to yield robust results.

Q. Which companies do you include in your Rebuttal Proxy Group?

A. The Proxy Group is comprised of the following twenty-six companies: 1) Alliant Energy Corp.; 2) Ameren Corp.; 3) American Electric Power Co., Inc.; 4) Avista Corp.; 5) Black Hills Corp.; 6) CenterPoint Energy, Inc.; 7) Consolidated Edison, Inc.; 8) Dominion Resources, Inc.; 9) DTE Energy Company; 10) Edison International; 11) El Paso Electric Co.; 12) Empire District Electric Co.; 13) Great Plains Energy Inc.; 14) IDACORP, Inc.; 15) NextEra Energy Inc.; 16) Northeast Utilities; 17) NorthWestern Corp.; 18) Pinnacle West Capital Corp.; 19) Portland General Electric Company; 20) Public Service Enterprise Group Incorporated; 21)

[46] *See* Bonbright, J. *Principles of Public Utility Rates*, 50 (1961).

SCANA Corporation; 22) Sempra Energy; 23) Southern Co.; 24) Vectren Corp.; 25) Westar Energy, Inc.; and 26) Xcel Energy Inc.

Q. Please identify the changes to your proxy group relative to the one used in your direct testimony.

A. The screening analysis performed called for the addition of seven companies to the proxy group and the elimination of five companies. The rationale for addition or elimination is set forth below:

Additions:

- I added Ameren Corp. because it now passes all screens, including the positive five-year growth forecast screen.
- I added Edison International because it now passes all screens, including the positive five-year growth forecast screen.
- I added Empire District Electric Co. because it now passes all screens, including the non-negative dividend growth screen.
- I added Public Service Enterprise Group Incorporated because it now passes all screens, including the positive five-year growth forecast screen. I added Great Plains Energy Inc. because it now passes all screens, including the credit rating screen.
- I added Sempra Energy as it now passes the revenue from regulated operations screen.
- I added Vectren Corp. as it now passes the revenue from regulated operations screen.

Eliminations:

- I eliminated Pepco Holdings Inc. because it does not pass the merger screen, due to its acquisition by Exelon Corporation. In addition, Pepco Holdings no longer passes the sustainable growth screen.
- I eliminated Cleco Corp as it no longer passes the merger screen, as it is being acquired by an investor group.
- I eliminated OGE Energy Corp as it no longer passes the non-negative dividend growth screen.
- I eliminated Wisconsin Energy Corp. because it does not pass the merger screen, due to its acquisition of Integrys Energy Group.
- I eliminated Duke Energy Corp. because it does not pass the merger screen, due to assets sold to Dynergy.

Q. Have you prepared exhibits illustrating your updated calculations?

A. Yes. Exhibit Nos. KGS-26 through KGS-32, KGS-35, and KGS-36 contain my updated analysis and application of the rate-of-return models to the Rebuttal Proxy Group. Exhibit Nos. KGS-33 and KGS-34 contain updated charts showing trends in dividend yields for utilities and the broader market, and yields on long-term treasury bonds, respectively.

Q. Please summarize your updated recommendation.

A. My updated analysis indicates that a reasonable rate of return for the Company's equity owners is 10.0 percent. This rate of return reflects the opportunity cost of capital for investments of comparable risks. It is reflective of current capital market conditions and consistent with the returns that have been authorized for comparable electric utilities.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit No. KGS-18
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Updated Summary of Cost of Equity Estimates

November 2014

Pacific Power & Light Company
Summary of Cost of Equity Estimates

Method (a)	Cost of Equity (b)
DCF Models	
Proxy Group Single-Stage DCF	9.00%
Yield + Growth	10.10%
Risk Premium Models	
CAPM	9.73%
Risk Premium	10.07%
Comparable Earnings Model	
Comparable Earnings (Dow Jones Utilities Index)	9.97%
Comparable Earnings (Dow Jones Industrial Average)	16.20%
Allowed Returns for Electric Utilities, Year-to-Date 2013	10.02%
Recommended Rate of Return	**10.00%**

Exhibit No. KGS-19
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

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PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Allowed ROE for Other Electric Utilities

November 2014

Allowed ROEs for State-Regulated Integrated Electric Utilities
2013

State	Company Name	Docket Number	Allowed Return on Equity (%)
Arkansas	Entergy Arkansas Inc.	D-13-028-U	9.3
Arizona	Tucson Electric Power Co.	D-E-01933A-12-0291	10
Arizona	UNS Electric Inc.	D-E-04204A-12-0504	9.5
Connecticut	United Illuminating Co.	D-13-01-19	9.15
Florida	Gulf Power Co.	D-130140-EI	10.25
Florida	Tampa Electric Co.	D-130040-EI	10.25
Georgia	Georgia Power Co.	D-36989	10.95
Hawaii	Maui Electric Company Ltd	D-2011-0092	9
Idaho	Avista Corp.	C-AVU-E-12-08	9.8
Indiana	Indiana Michigan Power Co.	Ca-44075	10.2
Kansas	Westar Energy Inc.	D-13-WSEE-629-RTS	10
Louisiana	Entergy Gulf States LA LLC	D-U-32707	9.95
Louisiana	Entergy Louisiana LLC	D-U-32708	9.95
Louisiana	Southwestern Electric Power Co	D-U-32220	10
Michigan	Consumers Energy Co.	C-U-17087	10.3
Michigan	Upper Peninsula Power Co.	C-U-17274	10.15
Minnesota	Northern States Power Co. - MN	D-E-002/GR-12-961	9.83
Missouri	Kansas City Power & Light	C-ER-2012-0174	9.7
Missouri	KCP&L Greater Missouri Op Co	C-ER-2012-0175 (MPS)	9.7
Missouri	KCP&L Greater Missouri Op Co	C-ER-2012-0175 (L&P)	9.7
North Carolina	Duke Energy Carolinas LLC	D-E-7, Sub 1026	10.2
North Carolina	Duke Energy Progress Inc.	D-E-2, Sub 1023	10.2
Nevada	Sierra Pacific Power Co.	D-13-06002	10.12
Oregon	PacifiCorp	D-UE-263	9.8
Oregon	Portland General Electric Co.	D-UE-262	9.75
South Carolina	Duke Energy Carolinas LLC	D-2013-59-E	10.2
Texas	Southwestern Electric Power Co	D-40443	9.65
Virginia	Virginia Electric & Power Co.	C-PUE-2013-00020	10
Washington	PacifiCorp	D-UE-130043	9.5
Washington	Puget Sound Energy Inc.	D-UE-130137	9.8
Wisconsin	Northern States Power Co - WI	D-4220-UR-119 (Elec)	10.2
Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-122 (Elec)	10.2
Average			**9.92**

Allowed ROEs for State-Regulated Integrated Electric Utilities
2014 (year to date)

State	Company Name	Docket Number	Allowed Return on
Florida	Florida Public Utilities Co.	D-140025-EI	10.25
Louisiana	Entergy Louisiana LLC	D-UD-13-01	9.95
North Dakota	Northern States Power Co. - MN	C-PU-12-813	9.75
New Mexico	Southwestern Public Service Co	C-12-00350-UT	9.96
Nevada	Nevada Power Co.	D-14-05004	9.8
Texas	Entergy Texas Inc.	D-41791	9.8
Utah	PacifiCorp	D-13-035-184	9.8
Vermont	Green Mountain Power Corp.	D-8190, 8191	9.6
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-119 (Elec)	10.4
Wyoming	Cheyenne Light Fuel Power Co.	D-20003-132-ER-13	9.9
Average			**9.92**

Source: SNL.

Exhibit No. KGS-20
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
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In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

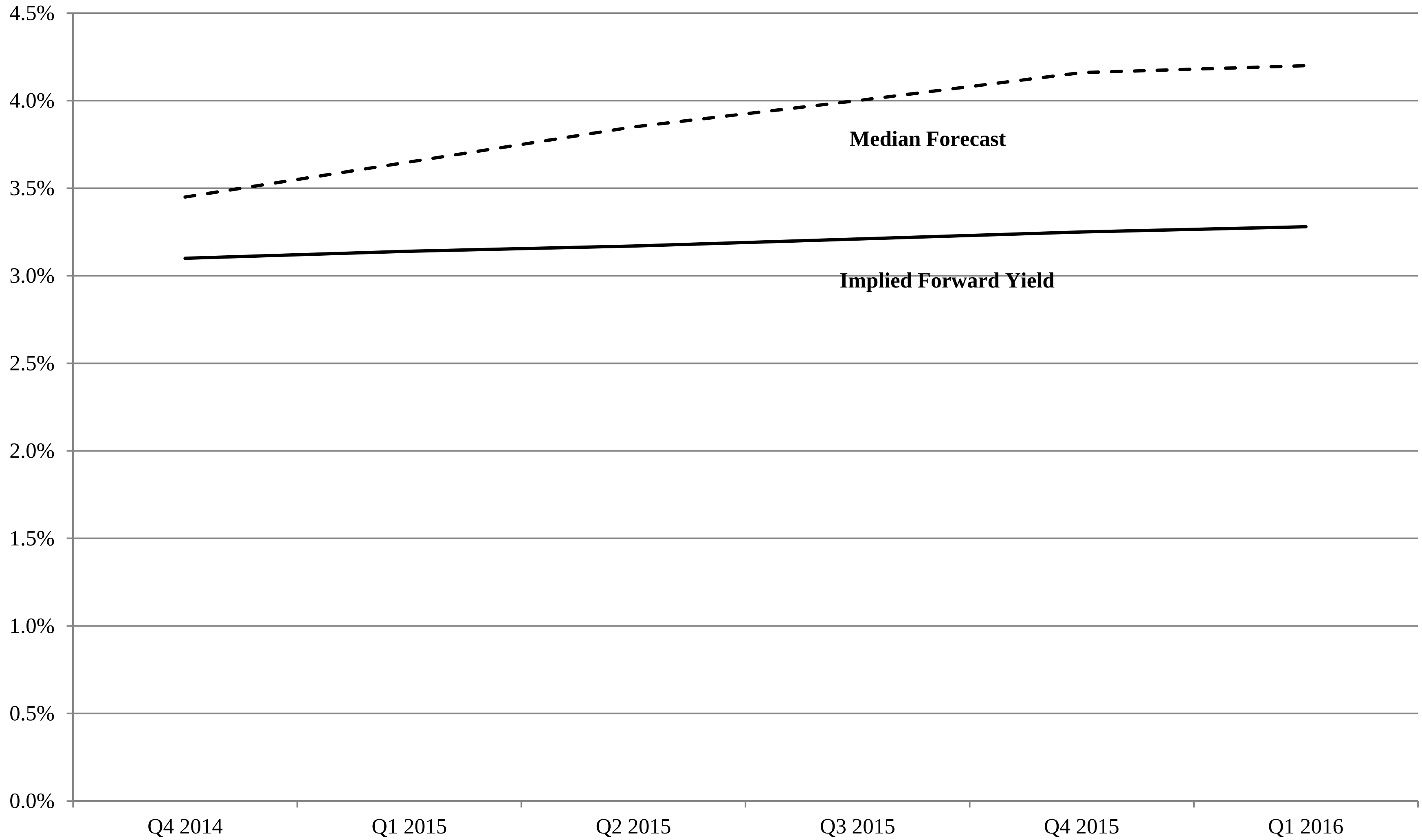
PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Bloomberg Yield Forecasts

November 2014

30-Year Treasury Yield Forecasts
As of October 31, 2014



Source: Bloomberg L.P.

Exhibit No. KGS-21
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
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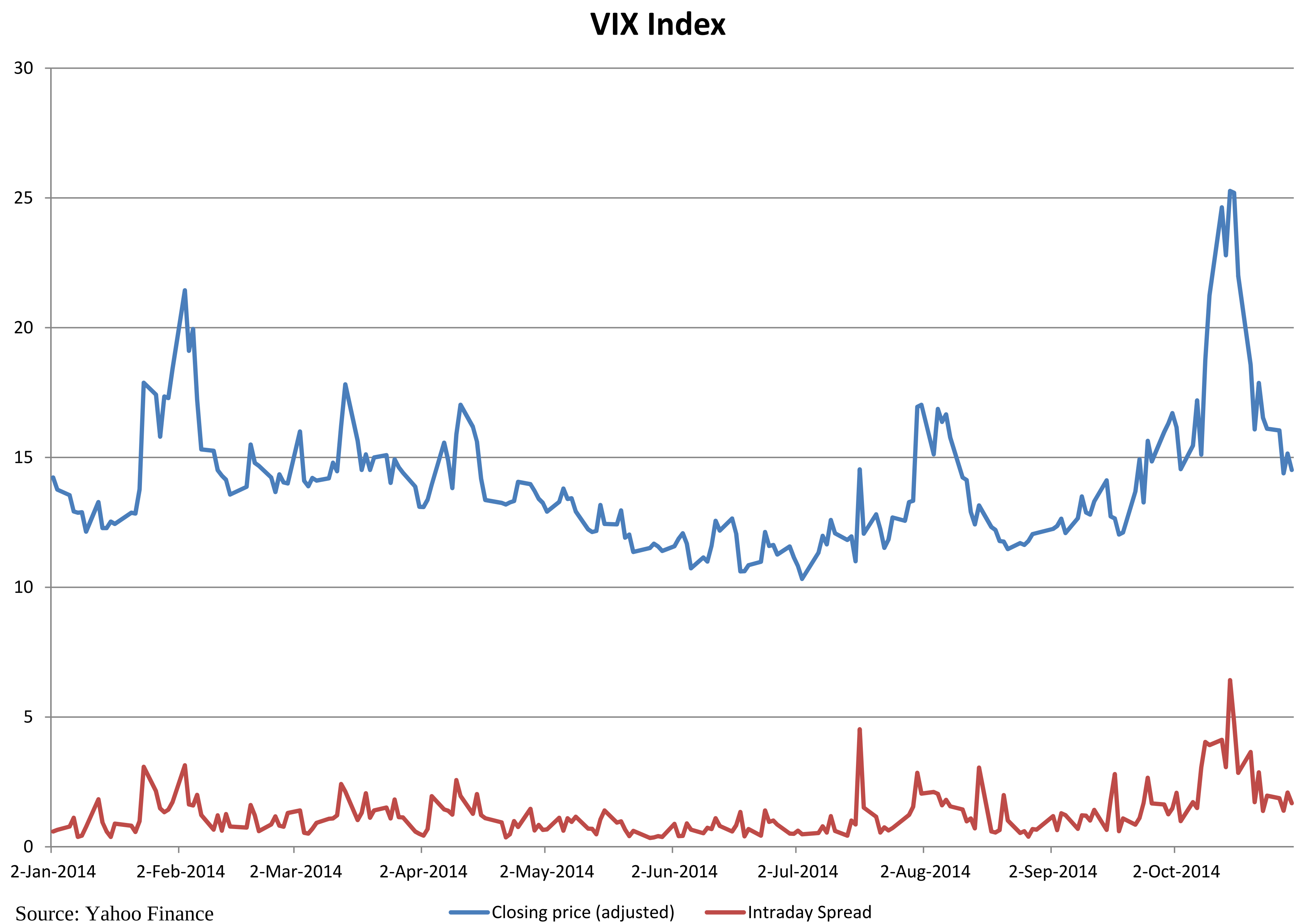
PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

VIX Index

November 2014



Source: Yahoo Finance

Exhibit No. KGS-22
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
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PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Large Company Stock Returns Over the Period 1987-2011 One-Year Returns

November 2014

Large Company Stock Returns Over the Period 1987-2011
One-Year Returns

Year	One-Year Return	One Year Return Greater than Current Market-Implied Expected Return?
(a)	(b)	(c)
1987	5.3%	No
1988	16.6%	Yes
1989	31.7%	Yes
1990	-3.1%	No
1991	30.5%	Yes
1992	7.6%	No
1993	10.1%	No
1994	1.3%	No
1995	37.6%	Yes
1996	23.0%	Yes
1997	33.4%	Yes
1998	28.6%	Yes
1999	21.0%	Yes
2000	-9.1%	No
2001	-11.9%	No
2002	-22.1%	No
2003	28.7%	Yes
2004	10.9%	No
2005	4.9%	No
2006	15.8%	Yes
2007	5.5%	No
2008	-37.0%	No
2009	26.5%	Yes
2010	15.1%	Yes
2011	2.1%	No
2012	16.0%	Yes
Count of Years Greater than 11.95%		**13**
Mean Return (1926-2012)	**11.36%**	
Median Return (1926-2012)	**14.30%**	

Notes:
Source: 2013 Ibbotson Valuation Yearbook Table B-1.
The source for the 11.95% market-implied return is Rebuttal Exhibit No. KGS-29

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

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PACIFIC POWER & LIGHT COMPANY

REDACTED EXHIBIT OF KURT G. STRUNK

Confidential Use of Pension Yields as Benchmark for Utility ROE

November 2014

Pacific Power & Light Company
Use of Pension Yields as Benchmark for Utility ROE

Market Return[1]	Risk Free Rate[2]	Equity Risk Premium	Utility Beta[3]	Estimated Utility Return
[1]	[2]	[3] = [1] - [2]	[4]	[5] = [2] + [4]*[3]
[redacted]	3.09%	[redacted]	0.73	[redacted]

[1] Source: Attach PC12 Confident
[2] Source: NERA Proxy Group Beta (see Exhibit KGS-30)
[3] Source: Federal Reserve, Constant Maturity 30-year Treasury Yield, 6 November 2014.

Exhibit No. KGS-24
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

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PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Comparison of Coal-Fired Generation Capacity and Energy Production

November 2014

Pacific Power & Light Company
Comparison of Coal-fired Generation Capacity and Energy Production

	2013 Operating Capacity from Coal (MW)	2013 Total Operating Capacity (MW)	Capacity from Coal as a Proportion of Total Capacity	2013 Net Generation from Coal (MWh)	2013 Total Net Generation (MWh)	Net Generation from Coal as a Proportion of Total Net Generation
PacifiCorp	6,630	11,093	60%	47,608,990	62,300,629	76%
Proxy Group	101,163	280,735	36%	413,022,830	1,045,198,055	40%
Industry	302,515	1,068,588	28%	1,402,058,795	3,587,974,550	39%

Source: SNL, 5 November 2014.

Exhibit No. KGS-25
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

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PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Proxy Group BR + SV

November 2014

Pacific Power & Light Company
Proxy Group
BR + SV

		R^1	D_e	V_e	V		R_{av}^2	B^3	$B*R^4$	$S*V^5$	B*R+S*V
		Estimated Return on Common Equity	Estimated Dividend per Share	Estimated Book Value/Share	Book Value/Share		Return on Average Equity				
Company	Ticker	2017-2019	2017-2019	2017-2019	2013	2012					
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Electric Proxy Group											
1 Alliant Energy Corporation	LNT	12.0%	$2.40	$34.65	$29.58	$ 28.25	12.3%	0.42	5.2%	0.0%	5.24%
2 Ameren Corporation	AEE	9.5%	$1.80	$32.00	$26.97	$ 27.27	9.4%	0.41	3.9%	1.0%	4.89%
3 American Electric Power Company, Inc.	AEP	10.0%	$2.50	$40.50	$32.98	$ 31.37	10.3%	0.38	3.9%	1.8%	5.76%
4 Avista Corporation	AVA	8.5%	$1.50	$25.75	$21.61	$ 21.06	8.6%	0.31	2.7%	0.8%	3.51%
5 Black Hills Corporation	BKH	9.0%	$1.90	$35.50	$29.39	$ 27.88	9.2%	0.41	3.7%	1.4%	5.19%
6 CenterPoint Energy, Inc.	CNP	14.5%	$1.30	$11.25	$10.09	$ 10.06	14.5%	0.20	2.9%	2.7%	5.64%
7 Consolidated Edison, Inc.	ED	9.0%	$2.75	$49.25	$41.81	$ 40.53	9.1%	0.38	3.5%	0.5%	3.97%
8 Dominion Resources, Inc.	D	14.0%	$2.80	$28.00	$20.02	$ 18.34	14.6%	0.29	4.2%	0.0%	4.15%
9 DTE Energy Company	DTE	10.0%	$3.30	$56.75	$44.73	$ 42.78	10.2%	0.42	4.3%	0.8%	5.08%
10 Edison International	EIX	11.0%	$2.05	$41.50	$30.50	$ 28.95	11.3%	0.55	6.2%	0.0%	6.22%
11 El Paso Electric Company	EE	9.5%	$1.35	$28.75	$23.44	$ 20.57	10.1%	0.51	5.1%	-1.0%	4.12%
12 The Empire District Electric Company	EDE	9.0%	$1.15	$20.25	$17.43	$ 16.90	9.1%	0.37	3.4%	2.0%	5.39%
13 Great Plains Energy Incorporated	GXP	7.5%	$1.20	$26.00	$22.58	$ 21.75	7.6%	0.38	2.9%	1.0%	3.97%
14 IDACORP, Inc.	IDA	8.0%	$2.00	$44.55	$36.84	$ 35.07	8.2%	0.44	3.6%	0.6%	4.21%
15 NextEra Energy, Inc.	NEE	12.0%	$3.90	$57.25	$41.47	$ 37.90	12.5%	0.43	5.4%	0.8%	6.20%
16 Northeast Utilitites	NU	9.5%	$2.00	$36.50	$30.49	$ 29.41	9.7%	0.42	4.1%	7.4%	11.47%
17 NorthWestern Corporation	NWE	9.5%	$1.90	$31.75	$26.60	$ 25.09	9.8%	0.37	3.6%	0.8%	4.42%
18 Pinnacle West Capital Corporation	PNW	9.5%	$2.75	$45.75	$38.07	$ 36.20	9.7%	0.37	3.6%	0.8%	4.34%
19 Portland General Electric Company	POR	8.5%	$1.40	$28.25	$23.30	$ 22.87	8.6%	0.42	3.6%	1.8%	5.39%
20 Public Service Enterprise Group Incorporated	PEG	10.5%	$1.65	$29.00	$22.95	$ 21.31	10.9%	0.46	5.0%	0.0%	4.99%
21 SCANA Corporation	SCG	10.0%	$2.35	$43.50	$33.08	$ 31.47	10.2%	0.46	4.7%	1.5%	6.19%
22 Sempra Energy	SRE	11.5%	$3.40	$55.50	$45.03	$ 42.42	11.8%	0.47	5.5%	0.2%	5.73%
23 The Southern Company	SO	12.5%	$2.36	$26.25	$21.43	$ 21.09	12.6%	0.28	3.5%	1.4%	4.92%
24 Vectren Corporation	VVC	14.0%	$1.55	$21.50	$18.86	$ 18.57	14.1%	0.49	6.8%	0.9%	7.71%
25 Westar Energy, Inc.	WR	9.5%	$1.60	$29.65	$23.88	$ 22.89	9.7%	0.43	4.2%	0.0%	4.19%
26 Xcel Energy Inc.	XEL	10.5%	$1.45	$24.25	$19.21	$ 18.19	10.8%	0.43	4.6%	1.1%	5.76%
Average		**10.35%**	**$2.09**	**$34.76**	**$28.17**	**$26.85**	**10.58%**	**0.40**	**4.24%**	**1.09%**	**5.33%**

Notes:

[1] Estimated future return on common equity, dividends per share, and book value per share as reported in *The Value Line Investment Survey: 19 September 2014; 22 August 2014; and 1 August 2014.*

[2] Rav=R*[(2*V13)/(V13+V12)]. This formula transforms the end-of-year projected *Value Line* return on equity into a mid-year return on equity.

[3] B=1-(De/(R*Ve)).

[4] B*R=B*Rav=(Rav-De/Ve).

[5] S*V equals the five year average of S, multiplied by current V, where S = annual growth rate of common shares outstanding and V = fraction of new funds provided that accrues to original shareholders.

Exhibit No. KGS-26
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Proxy Group S and V Estimation

November 2014

Pacific Power & Light Company
Proxy Group
S and V Estimation

Company	Ticker	Growth Rate of Common Shares Outstanding (S) [1] 2009 (a)	2010 (b)	2011 (c)	2012 (d)	2013 (e)	Average S[2] (f)	2012 Book Value per Share[3] (g)	Adjusted Stock Price[4] (h)	V[5] (i) = 1 - (g)/(h)	S*V (j) = ((f)*(i))
Electric Proxy Group											
1 Alliant Energy Corporation	LNT	0.19%	0.21%	0.12%	-0.03%	-0.05%	0.09%	$28.25	$62.37	54.71%	0.05%
2 Ameren Corporation	AEE	11.82%	1.26%	0.92%	0.01%	0.00%	2.80%	$27.27	$43.21	36.89%	1.03%
3 American Electric Power Company, Inc.	AEP	17.73%	0.58%	0.54%	0.47%	0.43%	3.95%	$31.37	$58.69	46.55%	1.84%
4 Avista Corporation	AVA	0.64%	4.16%	2.28%	2.38%	0.45%	1.98%	$21.06	$35.38	40.47%	0.80%
5 Black Hills Corporation	BKH	0.85%	0.77%	11.84%	0.66%	0.66%	2.96%	$27.88	$54.57	48.91%	1.45%
6 CenterPoint Energy, Inc.	CNP	13.19%	8.41%	0.31%	0.33%	0.36%	4.52%	$10.06	$24.91	59.61%	2.70%
7 Consolidated Edison, Inc.	ED	2.70%	3.74%	0.44%	-0.01%	0.00%	1.37%	$40.53	$63.66	36.34%	0.50%
8 Dominion Resources, Inc.	D	2.78%	-3.10%	-1.91%	1.12%	0.94%	-0.04%	$18.34	$72.73	74.78%	-0.03%
9 DTE Energy Company	DTE	1.46%	2.44%	-0.11%	1.83%	2.75%	1.67%	$42.78	$82.42	48.10%	0.81%
10 Edison International	EIX	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$28.95	$63.11	54.12%	0.00%
11 El Paso Electric Company	EE	-2.14%	-3.07%	-6.13%	0.38%	0.40%	-2.11%	$20.57	$38.80	46.98%	-0.99%
12 The Empire District Electric Company	EDE	12.15%	9.11%	0.96%	1.19%	1.32%	4.95%	$16.90	$28.51	40.72%	2.01%
13 Great Plains Energy Incorporated	GXP	13.55%	0.21%	0.32%	12.77%	0.22%	5.42%	$21.75	$26.88	19.08%	1.03%
14 IDACORP, Inc.	IDA	2.09%	3.15%	1.09%	0.42%	0.14%	1.38%	$35.07	$63.21	44.52%	0.61%
15 NextEra Energy, Inc.	NEE	1.15%	1.75%	-1.15%	1.92%	2.59%	1.25%	$37.90	$101.01	62.48%	0.78%
16 Northeast Utilitites	NU	12.70%	0.47%	0.40%	77.27%	0.39%	18.25%	$29.41	$49.37	40.42%	7.38%
17 NorthWestern Corporation	NWE	0.19%	0.64%	0.14%	2.59%	4.11%	1.53%	$25.09	$52.75	52.43%	0.80%
18 Pinnacle West Capital Corporation	PNW	0.54%	7.24%	0.44%	0.45%	0.40%	1.81%	$36.20	$62.25	41.85%	0.76%
19 Portland General Electric Company	POR	20.18%	0.15%	0.05%	0.27%	3.35%	4.80%	$22.87	$36.73	37.74%	1.81%
20 Public Service Enterprise Group Incorporate	PEG	-0.01%	0.00%	0.00%	-0.01%	-0.01%	-0.01%	$21.31	$41.38	48.50%	0.00%
21 SCANA Corporation	SCG	4.72%	3.33%	1.91%	1.64%	6.81%	3.68%	$31.47	$55.75	43.55%	1.60%
22 Sempra Energy	SRE	1.31%	-2.46%	-0.22%	1.02%	0.86%	0.10%	$42.42	$110.55	61.63%	0.06%
23 The Southern Company	SO	5.46%	2.89%	2.58%	0.31%	2.23%	2.69%	$21.09	$46.77	54.91%	1.48%
24 Vectren Corporation	VVC	0.09%	0.74%	0.24%	0.37%	0.24%	0.34%	$18.57	$44.83	58.58%	0.20%
25 Westar Energy, Inc.	WR	0.70%	2.81%	12.10%	0.64%	1.38%	3.53%	$22.89	$37.59	39.10%	1.38%
26 Xcel Energy Inc.	XEL	0.82%	5.43%	0.86%	0.30%	2.05%	1.89%	$18.19	$33.60	45.86%	0.87%
Total		**4.80%**	**1.95%**	**1.08%**	**4.16%**	**1.23%**	**2.65%**	**$26.85**	**$53.50**	**47.65%**	**1.11%**

Notes:
[1] Source: *The Value Line Investment Survey: 19 September 2014; 22 August 2014; and 1 August 2014.*
[2] Average common shares outstanding growth rate for 2009-2013.
[3] Source: *The Value Line Investment Survey: 19 September 2014; 22 August 2014; and 1 August 2014.*
[4] Source: FactSet Research Systems, 4 November 2014.
[5] V is the adjusted stock price relative to the book value. 1- (Book Value per Share/Adjusted Stock Price).

Exhibit No. KGS-27
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Proxy Group DCF Analysis

November 2014

Pacific Power & Light Company
Proxy Groups
DCF Analysis

			Growth Rate ("g")		Dividend Yield[1]	Adjusted Dividend Yield[2]	Return on Equity[3]
	Company	**Ticker**	**Thomson Reuters[4]**	**BR+SV[5]**			
			Thomson Reuters Five Year Growth Rate	*B*R+S*V*	*12 month Dividend Yield*	(((c)+(d))/2+1) * (e)	((c)+(d))/2 +(f)
	(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**
Electric Proxy Group							
1	Alliant Energy Corporation	LNT	4.80%	5.24%	3.59%	3.77%	8.79%
2	Ameren Corporation	AEE	8.90%	4.89%	4.12%	4.41%	11.30%
3	American Electric Power Company, Inc.	AEP	4.97%	5.76%	3.92%	4.13%	9.49%
4	Avista Corporation	AVA	5.00%	3.51%	4.11%	4.28%	8.54%
5	Black Hills Corporation	BKH	7.00%	5.19%	2.85%	3.02%	9.12%
6	CenterPoint Energy, Inc.	CNP	3.87%	5.64%	3.83%	4.01%	8.76%
7	Consolidated Edison, Inc.	ED	2.60%	3.97%	4.46%	4.61%	7.89%
8	Dominion Resources, Inc.	D	6.17%	4.15%	3.44%	3.62%	8.78%
9	DTE Energy Company	DTE	5.87%	5.08%	3.57%	3.77%	9.24%
10	Edison International	EIX	3.38%	6.22%	2.61%	2.74%	7.54%
11	El Paso Electric Company	EE	7.00%	4.12%	2.98%	3.15%	8.71%
12	The Empire District Electric Company	EDE	3.00%	5.39%	4.23%	4.40%	8.60%
13	Great Plains Energy Incorporated	GXP	5.00%	3.97%	3.63%	3.79%	8.28%
14	IDACORP, Inc.	IDA	4.00%	4.21%	3.16%	3.29%	7.39%
15	NextEra Energy, Inc.	NEE	6.47%	6.20%	3.03%	3.23%	9.56%
16	Northeast Utilitites	NU	6.31%	11.47%	3.46%	3.77%	12.66%
17	NorthWestern Corporation	NWE	4.00%	4.42%	3.37%	3.51%	7.73%
18	Pinnacle West Capital Corporation	PNW	3.95%	4.34%	4.13%	4.30%	8.44%
19	Portland General Electric Company	POR	7.83%	5.39%	3.44%	3.67%	10.28%
20	Public Service Enterprise Group Incorporated	PEG	1.74%	4.99%	4.05%	4.18%	7.55%
21	SCANA Corporation	SCG	4.65%	6.19%	4.13%	4.35%	9.77%
22	Sempra Energy	SRE	7.47%	5.73%	2.64%	2.81%	9.41%
23	The Southern Company	SO	3.62%	4.92%	4.77%	4.98%	9.25%
24	Vectren Corporation	VVC	4.50%	7.71%	3.72%	3.95%	10.05%
25	Westar Energy, Inc.	WR	3.20%	4.19%	3.97%	4.12%	7.81%
26	Xcel Energy Inc.	XEL	4.51%	5.76%	3.83%	4.03%	9.16%
	Average						**9.00%**

Notes:

[1] Dividend yield calculated as (last 4 quarterly dividends) / (12 month average price). FactSet Research Systems, 4 November 2014; Bloomberg L.P., 4 November 2014.

[2] Adjusted Dividend Yield = Dividend Yield multiplied by (1 + g).

[3] Return on Equity = Average Growth Rate + Adjusted Dividend Yield.

[4] Source: Thomson Reuters 5 Year Growth Rate, Yahoo! Finance, accessed 10 November 2014.

[5] Source: Exhibit No.___(KGS-26).

Exhibit No. KGS-28
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Yield + Growth Model

November 2014

Pacific Power & Light Company
Yield + Growth Model

	Item	Value
(a)	Electric Utility Industry Average Dividend Yield[1]	3.70%
(b)	Electric Utility Industry Average Growth Rate[2]	6.40%
(a) + (b)	Cost of Equity	10.10%

Sources:

[1] Value Line, "Electric Utility (West) Industry," 31 October 2014.

[2] Zacks Investment Research, 3 November 2014.

Exhibit No. KGS-29
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

S&P 500 Forward Looking Market Risk Premium

November 2014

Pacific Power & Light Company
S&P 500 Forward Looking Market Risk Premium

Dividend Yield[1]	Growth Rate[2]	Risk Free Rate[3]	Market Risk Premium
(a)	(b)	(c)	(d) = (a)*[1 + (b)] + (b) - (c)
2.03%	9.92%	3.09%	9.06%

Notes:

[1] Dividend yield calculated as (total dividends) / (12 month average price).
Bloomberg Financial, L.P., 4 November 2014.

[2] Source: Bloomberg Financial, L.P., Composite of Long-Term EPS Analyst Estimates for the S&P 500, 6 November 2014.

[3] Source: Federal Reserve, Constant Maturity 30-year Treasury Yield, 6 November 2014.

Exhibit No. KGS-30
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Proxy Group Capital Asset Pricing Model

November 2014

Pacific Light & Power Company
Proxy Group
Capital Asset Pricing Model (CAPM)

					Forward Looking Market Risk Premium	CAPM Cost of Equity
No.	**Company**	**Ticker**	**30-Year T-Bond Return (Rf)[1]**	**Beta Value Line[2]**	**Top-Down DCF - 30 Yr T-Bond Return[3]**	**Based on Forward Looking Market Risk Premium**
	(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f) = (c) + (d)*(e)**
Electric Proxy Group						
1	Alliant Energy Corporation	LNT	3.09%	0.80	9.06%	10.34%
2	Ameren Corporation	AEE	3.09%	0.75	9.06%	9.89%
3	American Electric Power Company, Inc.	AEP	3.09%	0.70	9.06%	9.43%
4	Avista Corporation	AVA	3.09%	0.75	9.06%	9.89%
5	Black Hills Corporation	BKH	3.09%	0.85	9.06%	10.79%
6	CenterPoint Energy, Inc.	CNP	3.09%	0.75	9.06%	9.89%
7	Consolidated Edison, Inc.	ED	3.09%	0.60	9.06%	8.53%
8	Dominion Resources, Inc.	D	3.09%	0.70	9.06%	9.43%
9	DTE Energy Company	DTE	3.09%	0.75	9.06%	9.89%
10	Edison International	EIX	3.09%	0.75	9.06%	9.89%
11	El Paso Electric Company	EE	3.09%	0.70	9.06%	9.43%
12	The Empire District Electric Company	EDE	3.09%	0.65	9.06%	8.98%
13	Great Plains Energy Incorporated	GXP	3.09%	0.85	9.06%	10.79%
14	IDACORP, Inc.	IDA	3.09%	0.80	9.06%	10.34%
15	NextEra Energy, Inc.	NEE	3.09%	0.70	9.06%	9.43%
16	Northeast Utilitites	NU	3.09%	0.75	9.06%	9.89%
17	NorthWestern Corporation	NWE	3.09%	0.70	9.06%	9.43%
18	Pinnacle West Capital Corporation	PNW	3.09%	0.70	9.06%	9.43%
19	Portland General Electric Company	POR	3.09%	0.75	9.06%	9.89%
20	Public Service Enterprise Group Incorporated	PEG	3.09%	0.75	9.06%	9.89%
21	SCANA Corporation	SCG	3.09%	0.75	9.06%	9.89%
22	Sempra Energy	SRE	3.09%	0.75	9.06%	9.89%
23	The Southern Company	SO	3.09%	0.60	9.06%	8.53%
24	Vectren Corporation	VVC	3.09%	0.80	9.06%	10.34%
25	Westar Energy, Inc.	WR	3.09%	0.75	9.06%	9.89%
26	Xcel Energy Inc.	XEL	3.09%	0.65	9.06%	8.98%
	Average			**0.73**		**9.73%**

Notes:

[1] Source: Federal Reserve, Constant Maturity 30-year Treasury Yield, 6 November 2014.

[2] Source: *The Value Line Investment Survey* : 19 September 2014; 22 August 2014; and 1 August 2014.

[3] See Exhibit No.___(KGS-29).

Exhibit No. KGS-31
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Bond Yield + Risk Premium

November 2014

Pacific Power & Light
Bond Yield + Risk Premium

		Model Parameters		Model Results	
Analysis	**Bond Rate**[1]	**Slope**	**Intercept**	**Risk Differential (Utilities Relative to Bond Yields)**[2]	**Risk Premium Model Equity Return**
	11/6/2014	X			
(a)	(b)	(c)	(d)	(e) = (b)*(c) + (d)	(f) = (b) + (e)
1 Authorized Returns to Risk Free Rate[3]	3.09%	-0.626392574	0.089006436	6.97%	10.06%
2 Authorized Returns to A Utility Bond Yield[4]	3.33%	-0.737919298	0.093135889	6.86%	10.19%
3 Authorized Returns to BBB Corporate Bond Yield[5]	4.79%	-0.612930246	0.081063763	5.17%	9.96%
Average					**10.07%**

Notes:

Authorized Returns are yearly averages from SNL Financial.

[1] Bond yields are as of 6 November 2014.

[2] The formula is y=ax + b, where y is a vector of authorized returns, a is the slope, x is a vector of bond yields, and b is the intercept.

[3] The Risk Free Rate is the annual average of 30 Year Treasury Yields, 1994-2013. 20 Year Treasury Yields are used in 2003-2005 when 30 Year Yields are not available. Source: Federal Reserve website.

[4] Source: The A Utility Bond Yield is provided by Bank of America Merrill Lynch Utility Bond Index, Bloomberg, L.P.

[5] The BBB Bond Yield is the Moody's seasoned Baa average annual returns, 1994-2013. Source: Federal Reserve website.

Exhibit No. KGS-32
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Comparable Earnings

November 2014

Pacific Power & Light Company
Comparable Earnings

Year	Dow Jones Utility Index Return on Book Equity	Dow Jones Industrials Index Return on Book Equity
(a)	(b)	(c)
2002	-5.61%	8.94%
2003	7.21%	20.30%
2004	12.85%	19.13%
2005	13.35%	16.25%
2006	13.51%	16.17%
2007	14.51%	6.65%
2008	14.55%	10.84%
2009	11.31%	17.49%
2010	10.94%	19.74%
2011	11.29%	20.59%
2012	7.29%	18.80%
2013	8.43%	19.53%
Average	**9.97%**	**16.20%**

Notes:
Source: Bloomberg L.P.

Exhibit No. KGS-33
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

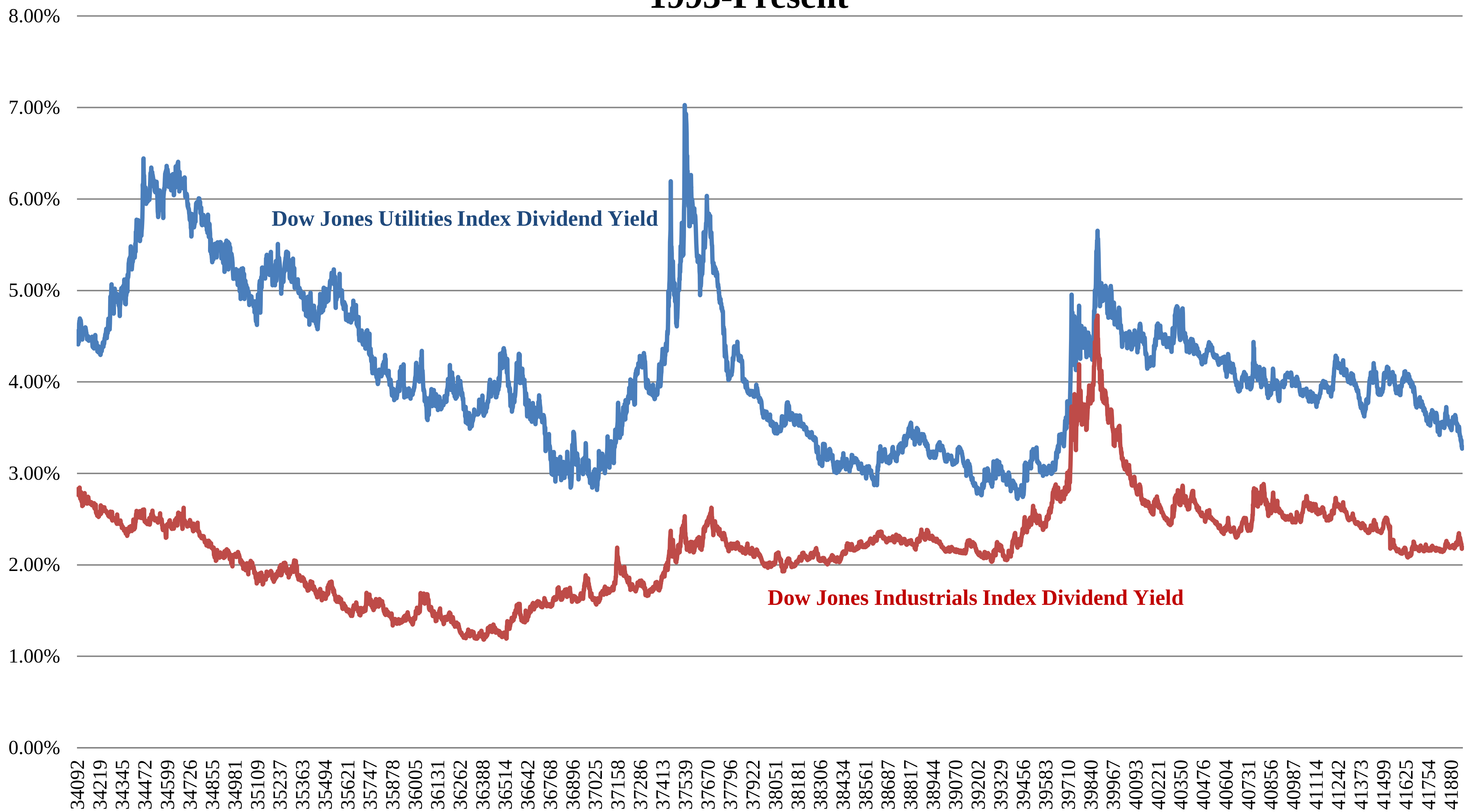
PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Bloomberg Dividend Yields 1993—Present

November 2014

Dividend Yields
1993-Present



Source: Bloomberg, LP

Exhibit No. KGS-34
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
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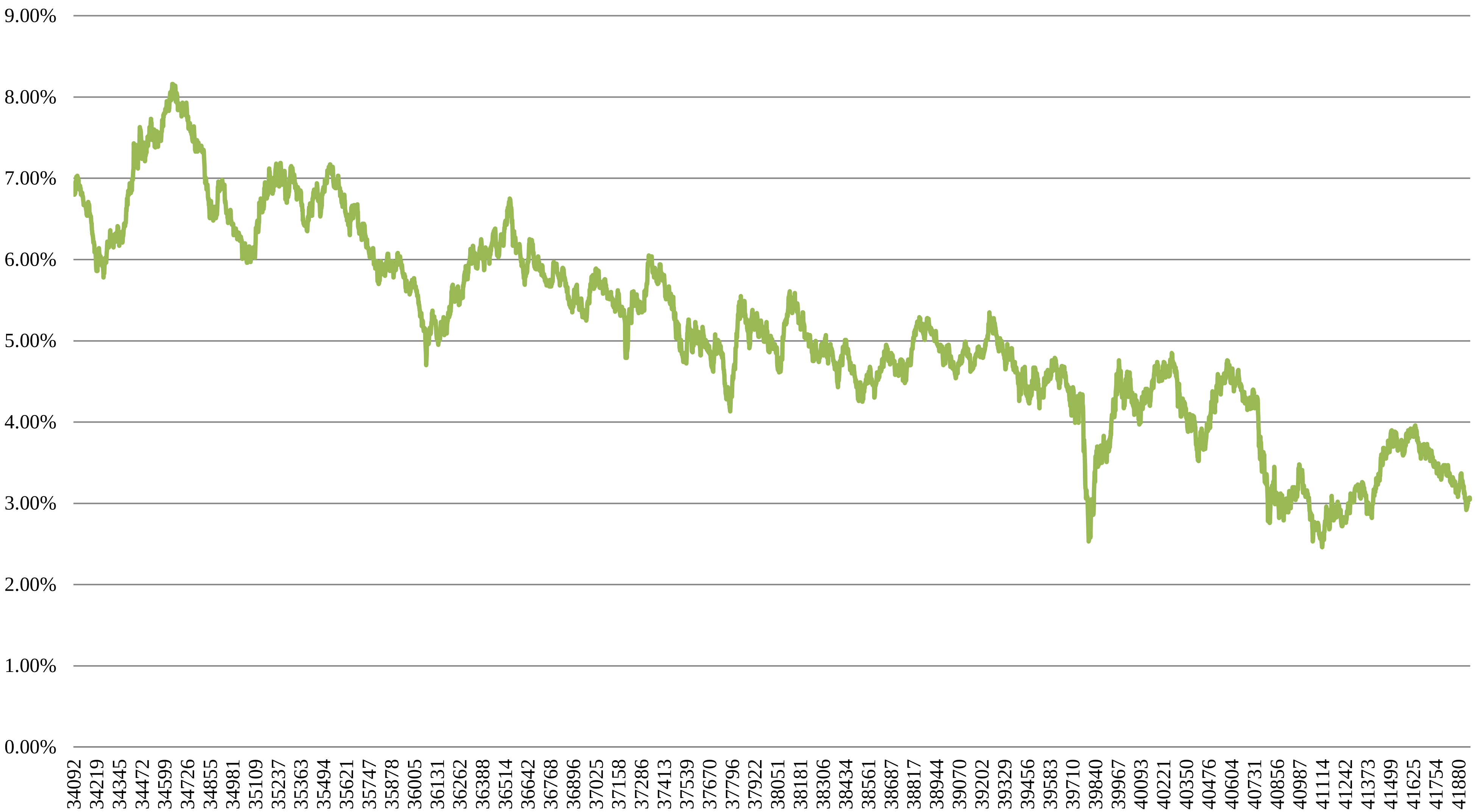
PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

30 Year Treasury Yields 1993—Present

November 2014

30 Year Treasury Yields
1993-Present



Source: Federal Reserve Website

Exhibit No. KGS-35
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
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PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Companies Used in Proxy Group and Comparison to PacifiCorp

November 2014

Pacific Power & Light Company
Companies Used in Proxy Group and Comparison to PacifiCorp

No.	Company Name	Ticker	Total Assets (Billions)	Revenue from Regulated Utility Operations (Billions)[1]	Electricity as % of Regulated Revenue[1]	Company Description[2]
Electricity Proxy Group						
1	Alliant Energy Corporation	LNT	$10.8	$3.0	86.73%	Alliant Energy Corporation provides public-utility service to customers in the Midwest. The Company's utility subsidiaries serve electric, natural gas, and water customers in Illinois, Iowa, Minnesota, and Wisconsin.
2	Ameren Corporation	AEE	$22.2	$5.8	84.02%	Ameren Corporation is a public utility holding company. The Company, through its subsidiaries, generates electricity, delivers electricity and distributes natural gas to customers in Missouri and Illinois.
3	American Electric Power Company, Inc.	AEP	$54.4	$13.4	100.00%	American Electric Power Company, Inc.(AEP)is a public utility holding company. The Company provides electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. AEP serves portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.
4	Avista Corporation	AVA	$4.3	$1.4	67.12%	Avista Corporation is an energy company that delivers products and solutions to business and residential customers throughout North America. The Company, through Avista Utilities, generates, transmits, and distributes electric and natural gas. Avista's other businesses include Avista Advantage and Avista Energy.
5	Black Hills Corporation	BKH	$3.7	$1.1	56.60%	Black Hills Corporation is a diversified energy company. The Company generates wholesale electricity, produce natural gas, oil and coal, and market energy. Black Hills serves customers in Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming.
6	CenterPoint Energy, Inc.	CNP	$22.9	$4.9	52.26%	CenterPoint Energy, Inc. is a public utility holding company. The Company, through its subsidiaries, conducts activities in electricity transmission and distribution, natural gas distribution and sales, interstate pipeline and gathering operations, and power generation.

Pacific Power & Light Company
Companies Used in Proxy Group and Comparison to PacifiCorp

No.	Company Name	Ticker	Total Assets (Billions)	Revenue from Regulated Utility Operations (Billions)[1]	Electricity as % of Regulated Revenue[1]	Company Description[2]
7	Consolidated Edison, Inc.	ED	$41.2	$10.4	84.42%	Consolidated Edison, Inc., through its subsidiaries, provides a variety of energy related products and services. The Company supplies electric service in New York, parts of New Jersey, and Pennsylvania as well as supplies electricity to wholesale customers.
8	Dominion Resources, Inc.	D	$46.8	$7.4	96.60%	Dominion Resources, Inc., a diversified utility holding company, generates, transmits, distributes, and sells electric energy in Virginia and northeastern North Carolina. The Company produces, transports, distributes, and markets natural gas to customers in the Northeast and Mid-Atlantic regions of the United States.
9	DTE Energy Company	DTE	$26.3	$6.6	80.10%	DTE Energy Company, a diversified energy company, develops and manages energy-related businesses and services nationwide. The Company, through its subsidiaries, generates, purchases, transmits, distributes, and sells electric energy in southeastern Michigan. DTE is also involved in gas pipelines and storage, unconventional gas exploration, development, and production.
10	Edison International	EIX	$44.4	$11.8	100.00%	Edison International, through its subsidiaries, develops, acquires, owns, and operates electric power generation facilities worldwide. The Company also provides capital and financial services for energy and infrastructure projects, as well as manages and sells real estate projects. Additionally, Edison provides integrated energy services, utility outsourcing, and consumer products.
11	El Paso Electric Company	EE	$2.7	$0.9	100.00%	El Paso Electric Company generates, distributes, and transmits electricity in west Texas and southern New Mexico. The Company also serves wholesale customers in Texas, New Mexico, California, and Mexico. El Paso Electric owns or has partial ownership interests in electrical generating facilities.
12	The Empire District Electric Company	EDE	$2.1	$0.5	92.74%	The Empire District Electric Company generates, purchases, transmits, distributes, and sells electricity. The Company supplies electricity to parts of Missouri, Kansas, Oklahoma, and Arkansas. Empire also provides water service to several towns in Missouri.

Pacific Power & Light Company
Companies Used in Proxy Group and Comparison to PacifiCorp

No.	Company Name	Ticker	Total Assets (Billions)	Revenue from Regulated Utility Operations (Billions)[1]	Electricity as % of Regulated Revenue[1]	Company Description[2]
13	Great Plains Energy Incorporated	GXP	$9.6	$2.3	100.00%	Great Plains Energy Incorporated provides electricity in the Midwest United States. The Company develops competitive generation for the wholesale market. Great Plains is also an electric delivery company with regulated generation. In addition, the Company is an investment company focusing on energy-related ventures nationwide that are unregulated with high growth potential.
14	IDACORP, Inc.	IDA	$5.3	$1.1	100.00%	IDACORP, Inc is the holding company for Idaho Power Company, an electric utility and IDACORP Energy, an energy marketing company. Idaho Power generates, purchases, transmits, distributes, and sells electric energy in southern Idaho, eastern Oregon, and northern Nevada. IDACORP Energy maintains electricity and natural gas marketing operations.
15	NextEra Energy, Inc.	NEE	$64.4	$10.1	100.00%	NextEra Energy, Inc. provides sustainable energy generation and distribution services. The Company specializes in wind and solar energy production. Through its subsidiaries, NextEra Energy also operates multiple commercial nuclear power units.
16	Northeast Utilitites	NU	$28.3	$6.2	90.69%	Northeast Utilities is a public utility holding company. The Company, through its subsidiaries, provides retail electric service to customers in Connecticut, New Hampshire, and western Massachusetts. Northeast also distributes natural gas throughout Connecticut.
17	NorthWestern Corporation	NWE	$3.5	$1.1	75.36%	NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas in the Upper Midwest and Northwest serving customers in Montana, South Dakota, and Nebraska.
18	Pinnacle West Capital Corporation	PNW	$13.4	$3.3	100.00%	Pinnacle West Capital Corporation is a utility holding company. The Company, through its subsidiary, provides either retail or wholesale electric service to most of the State of Arizona. The Company, through a subsidiary, also is involved in real estate development activities in the western United States.

Pacific Power & Light Company
Companies Used in Proxy Group and Comparison to PacifiCorp

No.	Company Name	Ticker	Total Assets (Billions)	Revenue from Regulated Utility Operations (Billions)[1]	Electricity as % of Regulated Revenue[1]	Company Description[2]
19	Portland General Electric Company	POR	$5.7	$1.8	100.00%	Portland General Electric Company is an electric utility involved in the generation, purchase, transmission, distribution, and sale of electricity in Oregon. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas to utilities and energy marketers.
20	Public Service Enterprise Group Incorporated	PEG	$31.7	$6.6	69.89%	Public Service Enterprise Group Incorporated is a public utility holding company. The Company, through its subsidiaries, generates, transmits, and distributes electricity and produces natural gas in the Northeastern and Mid Atlantic United States.
21	SCANA Corporation	SCG	$14.6	$3.2	75.96%	SCANA Corporation is a holding company involved in regulated electric and natural gas utility operations, telecommunications, and other energy-related businesses. The Company serves electric customers in South Carolina and natural gas customers in South Carolina, North Carolina, and Georgia. SCANA also has investments in several southeastern telecommunications companies.
22	Sempra Energy	SRE	$36.5	$7.0	46.24%	Sempra Energy is an energy services holding company with operations throughout the United States, Mexico, and other countries in South America. The Company, through its subsidiaries, generates electricity, delivers natural gas, operates natural gas pipelines and storage facilities, and operates a wind power generation project.
23	The Southern Company	SO	$63.1	$15.7	100.00%	The Southern Company is a public utility holding company. The Company, through its subsidiaries, generates, wholesales, and retails electricity in the southeastern United States. The Company also offers wireless telecommunications services, and provides businesses with two-way radio, telephone, paging, and Internet access services as well as wholesales fiber optic solutions.

Pacific Power & Light Company
Companies Used in Proxy Group and Comparison to PacifiCorp

No.	Company Name	Ticker	Total Assets (Billions)	Revenue from Regulated Utility Operations (Billions)[1]	Electricity as % of Regulated Revenue[1]	Company Description[2]
24	Vectren Corporation	VVC	$5.1	$1.3	44.63%	Vectren Corporation distributes gas in Indiana and western Ohio and electricity in southern Indiana. The Company's subsidiaries provide energy-related products and services, including energy marketing, fiber-optic telecommunications services, and utility related services. Vectren's services include materials management, debt collection, locating, trenching and meter reading services.
25	Westar Energy, Inc.	WR	$9.3	$2.3	100.00%	Westar Energy, Inc. is an electric utility company servicing customers in Kansas. The company provides electric generation, transmission and distribution services.
26	Xcel Energy Inc.	XEL	$31.1	$10.1	84.71%	Xcel Energy, Inc. provides electric and natural gas services. The Company offers a variety of energy-related services, including generation, transmission, and distribution of electricity and natural gas throughout the United States. Xcel utilities serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin.
	PacifiCorp	**PPW**	**$21.7**	**$4.9**	**100.00%**	PacifiCorp provides electric utility services. The Company generates, transmits, and distributes electricity. PacifiCorp serves customers throughout the United States.

Notes:

[1] Source: SNL

[2] Source: Bloomberg Financial, L.P.

Exhibit No. KGS-36
Docket UE-140762 *et al.*
Witness: Kurt G. Strunk

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
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In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF KURT G. STRUNK

Proxy Group Screening Results

November 2014

Proxy Group Screening Results

	Company	Ticker	Security Name	Classified as Electric Utility?	Has Credit Rating from Moody's or S&P Within Specified Band	Non-Negative Dividend Growth in Last 10 Quarters?	Positive 5 Year Growth Forecast?	Does not have merger or other extraordinary activity within the past six months ?	Greater than 50% of Revenues from Regulated Operations?	No Miscellaneous Issues that Warrant Exclusion from Proxy Group?	Market Value Greater than $1 Billion?	Include?
1	**Alliant Energy Corp.**	LNT	LNT US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
2	**Ameren Corp.**	AEE	SRE US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
3	**American Electric Power Co., Inc.**	AEP	AEP US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
4	**Avista Corp.**	AVA	AVA US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
5	**Black Hills Corp.**	BKH	BKH US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
6	**CenterPoint Energy, Inc.**	CNP	CNP US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
7	**Consolidated Edison, Inc.**	ED	CNL US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
8	**Dominion Resources, Inc.**	D	ED US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
9	**DTE Energy Co.**	DTE	D US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
10	**Edison International**	EIX	EIX US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
11	**El Paso Electric Co.**	EE	DUK US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
12	**Empire District Electric Co.**	EDE	EDE US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
13	**Great Plains Energy Inc.**	GXP	AEE US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
14	**IDACORP, Inc.**	IDA	IDA US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
15	**NextEra Energy, Inc.**	NEE	EE US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
16	**Northeast Utilities**	NU	NEE US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
17	**NorthWestern Corp.**	NWE	NU US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
18	**Pinnacle West Capital Corp.**	PNW	NWE US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
19	**Portland General Electric Co.**	POR	PNW US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20	**Public Service Enterprise Group Incorpora**	PEG	PEG US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21	**SCANA Corp.**	SCG	POR US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
22	**Sempra Energy**	SRE	XEL US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23	**Southern Co.**	SO	SCG US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
24	**Vectren Corp.**	VVC	VVC US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
25	**Westar Energy, Inc.**	WR	SO US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
26	**Xcel Energy Inc.**	XEL	WEC US Equity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
27	Allete, Inc.	ALE	ALE US Equity	Yes	Yes	Yes	Yes	Yes	No			
28	Cleco Corp.	CNL	GXP US Equity	Yes	Yes	Yes	Yes	No				
29	Duke Energy Corp.	DUK	DTE US Equity	Yes	Yes	Yes	Yes	No				
30	Wisconsin Energy Corp.	WEC	WR US Equity	Yes	Yes	Yes	Yes	No				
31	Integrys Energy Group, Inc.	TEG	TEG US Equity	Yes	Yes	Yes	No					
32	Pepco Holdings, Inc.	POM	POM US Equity	Yes	Yes	Yes	No					
33	PG&E Corp.	PCG	PCG US Equity	Yes	Yes	Yes	No					
34	TECO Energy, Inc.	TE	TE US Equity	Yes	Yes	Yes	No					
35	ITC Holdings Corp.	ITC	ITC US Equity	Yes	Yes	No						
36	OGE Energy Corp.	OGE	OGE US Equity	Yes	Yes	No						
37	CMS Energy Corporation	CMS	CMS US Equity	Yes	No							
38	Entergy Corp.	ETR	ETR US Equity	Yes	No							
39	Exelon Corp.	EXC	EXC US Equity	Yes	No							
40	FirstEnergy Corp.	FE	FE US Equity	Yes	No							
41	Hawaiian Electric Industries, Inc.	HE	HE US Equity	Yes	No							
42	MGE Energy, Inc.	MGEE	MGEE US Equity	Yes	No							
43	Otter Tail Corp.	OTTR	OTTR US Equity	Yes	No							
44	PNM Resources, Inc.	PNM	PNM US Equity	Yes	No							
45	PPL Corp.	PPL	PPL US Equity	Yes	No							
46	UIL Holdings Corp.	UIL	UIL US Equity	Yes	No							
47	Unitil Corp.	UTL	UTL US Equity	Yes	No							
	Total Passed			**47**	**36**	**34**	**30**	**27**	**26**	**26**	**26**	**26**

Exhibit No. BNW-16T
Docket UE-140762 *et al.*
Witness: Bruce N. Williams

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF BRUCE N. WILLIAMS

November 2014

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ATTACHED EXHIBITS

Exhibit No. BNW-17—Standard & Poor's Ratings Direct Report, "Corporate Methodology: Ratios and Adjustments" (November 19, 2013)

Exhibit No. BNW-18—Standard & Poor's Credit Assessment

Exhibit No. BNW-19—Regulatory Research Associates, "Regulatory Focus, Major Rate Case Decisions – January—June 2014" (July 10, 2014)

Exhibit No. BNW-20—Standard & Poor's Ratings Direct Report, "Corporate Methodology" (November 19, 2013)

Q. Are you the same Bruce N. Williams who previously submitted direct testimony in this case on behalf of Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to demonstrate the reasonableness of my recommendations on capital structure, cost of debt, and overall rate of return (ROR). I also address the recommendations from Washington Utilities and Transportation Commission (Commission) Staff witness Mr. David C. Parcell, the Public Counsel Division of the Attorney General's Office (Public Counsel) witness Mr. Stephen G. Hill, and Boise White Paper, LLC (Boise) witness Mr. Michael P. Gorman. Mr. Kurt G. Strunk responds to the cost of equity recommendations sponsored by these witnesses, and also addresses the positions of Staff and intervenors on capital structure and credit metrics.

Q. Please summarize your testimony.

A. I demonstrate that the Company's actual capital structure with 51.73 percent common equity, and the 7.67 percent ROR it produces, provides the balance of economy and safety the Commission requires. I provide evidence that the Company's capital structure and resulting ROR are reasonable, consistent with those of comparable electric utilities, and result in lower cost to customers than a hypothetical capital structure that takes into account the impact of higher leverage on the Company's debt and equity costs.

The other parties' proposed capital structures, which rely on a 49.1 percent common equity ratio, are not an appropriate alternative to the Company's recommendations. The analyses supporting the other parties' recommended overall rates of return and their conclusions that decreased returns will not harm the Company's credit ratings do not follow rating agency guidance and are not supported by facts.

Q. Have you reviewed your cost of capital recommendations on rebuttal to determine if any updates are warranted?

A. Yes. My cost of capital recommendations, which are based on the 12-month period ending December 31, 2014, have not changed since the Company's initial filing.

REPLY TO STAFF'S PROPOSED CAPITAL STRUCTURE

Q. What is Staff's proposed capital structure?

A. Staff recommends the hypothetical capital structure adopted in Order 05 in Docket UE-130043 (the 2013 Order).

Q. How does Mr. Parcell support Staff's recommended hypothetical capital structure?

A. Mr. Parcell relies on the 2013 Order and the average common equity ratio of various groups of electric utility companies.

Q. Please comment on Mr. Parcell's use of average common equity ratios.

A. First, it is my understanding that the Commission has been skeptical of comparing a company's equity ratio to those of comparable other utilities because the "individual circumstances of regulated utilities must be taken into account when determining the equity ratio that is appropriate for a given company at a particular point in time."[1] Thus, the Commission concluded that comparisons to other utilities "are not particularly useful measures to guide our decision."[2]

Second, by its very definition an "average" of other utilities' capital structures will mean that there are results both higher and lower than the average. Simply being higher (or lower) than the average should not rule out a capital structure as inappropriate and unreasonable.

Third, if the Commission decides to consider average equity ratios, Mr. Strunk and I both provide evidence that the Company's actual capital structure is more in line with the industry average than the proposed hypothetical capital structure.

Q. Do you agree with Mr. Parcell's statement that the average common equity ratio authorized for electric utilities in 2013 was about 49 percent?

A. No, the source of this statement, Exhibit No. DCP-16, is misleading. The data set for that exhibit includes many unrated utilities or those with ratings of Baa1 or lower, which are not comparable to the Company. Of the 22 comparable utilities, 19 had a common equity component listed. The average common equity of the 19 electric utilities that are A-rated is 51.24 percent, more than 200 basis points higher than Mr. Parcell claims and in line with the Company's actual common equity of 51.73 percent. In fact, only four A-rated utilities in Mr. Parcell's group of 19 had a common equity percentage below 50 percent.

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[1] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.* Dockets UG-040640 et al., Order 06 ¶ 30 (Feb. 18, 2005).
[2] *Id.*

Q. Did Mr. Parcell provide any testimony comparing the Company's proposed overall ROR to industry averages?

A. No, Mr. Parcell did not provide any comparison of the Company's proposed overall ROR to industry averages. When determining the balance between safety and economy in a capital structure, the resulting ROR is a critical factor.[3] As shown in Table 3 in my direct testimony, the Company's current ROR of 7.36 percent in Washington is the lowest in any of its states, and Staff's position in this case would reduce it further by almost 30 basis points. As discussed in more detail below, the Company's proposed ROR of 7.67 percent is in line with current RORs of comparable companies.

Q. Mr. Parcell attempts to support his hypothetical capital structure through a discussion concerning "double leverage." Has the Commission previously considered this issue?

A. Yes. The Commission has twice heard arguments in support of a "double leverage" adjustment and, in each case, rejected them.[4] When approving the merger of PacifiCorp and MidAmerican Energy Holdings Company (now Berkshire Hathaway Energy or BHE), the Commission adopted "state of the art" ring-fencing provisions intended to insulate PacifiCorp from the risks of leverage financing at the parent company. In rejecting double leverage adjustments related to BHE, the Commission found that such adjustments:

[3] In fact, the overall ROR is what the Commission commonly refers to as "economy." *See Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Order 05 ¶ 25 (Dec. 4, 2013).
[4] *See Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 (Apr. 17, 2006); *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-061546, Order 08 (June 21, 2007).

> [V]iolate the familiar principle in utility law that financial benefits should follow burden of risks. . . If the risks and costs of activities at the parent-level are born exclusively by shareholders—because customers are insulated from them by the ring fence—then it is fair and appropriate for the shareholders, and not the customers, to receive the benefits that result from those activities.[5]

Q. Are there cost of capital items on which you and Mr. Parcell agree?

A. Yes. Mr. Parcell accepts the Company's proposed costs of preferred stock and long-term debt.[6] The cost of long-term debt that Mr. Parcell accepts (5.19 percent), however, is the Company's proposed cost under its actual capital structure. The cost of long-term debt if the Commission utilizes the hypothetical capital structure Mr. Parcell recommends is 5.80 percent, as shown in the Company's alternative overall cost of capital.[7]

Credit Metrics

Q. Please comment on Mr. Parcell's reliance on a pre-tax interest coverage ratio to support his overall cost of capital recommendation.

A. Mr. Parcell's analysis is perfunctory, relying on a single credit metric (the pre-tax interest coverage ratio) that he admits is no longer used by the rating agencies.[8] Mr. Parcell's model also does not account for the other adjustments proposed by Staff witnesses in this case, and does not include the financing costs of assets under construction. There is therefore no factual basis for his claims that his proposed capital structure and costs of capital would support the Company's current credit ratings. In fact, as I have demonstrated, the opposite is true.

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[5] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 ¶ 285 (Apr. 17, 2006).
[6] Testimony of David C. Parcell, Exhibit No. DCP-1T at 2.
[7] Direct Testimony of Bruce N. Williams, Exhibit No. BNW-1T at 3.
[8] Testimony of David C. Parcell, Exhibit No. DCP-15 at 1.

REPLY TO PUBLIC COUNSEL'S PROPOSED CAPITAL STRUCTURE AND COST OF DEBT

Q. Please summarize Mr. Hill's proposed capital structure and costs of capital.

A. Mr. Hill proposes a hypothetical capital structure and costs of capital consistent with the Company's alternative overall cost of capital, but with an 8.90 percent return on equity. Mr. Strunk responds to Mr. Hill's return on equity recommendation.

Q. Are there specific costs of capital on which you and Mr. Hill agree?

A. Yes. Mr. Hill and I agree that if the Commission adopts a capital structure containing less common equity than the Company's actual capital structure, a corresponding increase in the costs of long-term and short-term debt is necessary. Mr. Hill accepts my recommended cost of long-term debt and short-term debt of 5.80 percent and 2.11 percent, respectively, if a hypothetical capital is utilized. Mr. Hill and I also agree on the cost of preferred stock of 6.75 percent.

Q. Is Mr. Hill correct that the Company has not paid dividends for eight years?

A. No. Mr. Hill testifies that "over the past eight years, PacifiCorp's common equity ratio has migrated from about 49 percent to about 52 percent as the Company has not paid dividends to its parent and has retained earning to raise the common equity ratio."[9] My direct testimony is clear that the Company initiated the payment of dividends in 2011 and expects to continue paying dividends to its parent company. Without these dividends, the Company's common equity level would be higher.[10]

[9] Testimony of Stephen C. Hill, Exhibit No. SGH-1CT at 22:14-16.
[10] Direct Testimony of Bruce N. Williams, Exhibit No. BNW-1T at 6:16-7:2.

Q. Does Mr. Hill acknowledge that PacifiCorp has retained its credit ratings over the past eight years?

A. Yes, his table on page 23 shows that PacifiCorp's corporate credit ratings have remained unchanged since 2006. This table also displays the common equity percentage over that time period. This underscores my point that PacifiCorp's increase in the common equity component has helped it retain its credit ratings and achieve a lower cost of debt. As Mr. Hill agrees, it is therefore inappropriate to adjust the capital structure for a lower common equity component without a corresponding increase to the cost of debt.

Q. Do you agree with Mr. Hill's implication that Washington is such a small relative percentage of PacifiCorp that the Commission's decisions have no impact on PacifiCorp's creditworthiness?

A. No. Each state that PacifiCorp serves is very important to the Company and, to be fair to all of its customers, the Company uses the same actual capital structure for each state jurisdiction.[11]

As I discussed in my direct testimony, regulatory treatment of a utility is critically important when rating agencies assess the creditworthiness of a utility.[12] While Mr. Hill may believe that it is unlikely that downgrade will occur if the Commission again adopts a hypothetical common equity component to set Washington rates, the Commission's decision in the 2013 Order indisputably drew negative attention from the rating agencies. For example, Moody's wrote:

[11] Washington, however, is the only state to include short-term debt in the capital structure for purposes of determining overall ROR.

[12] *See* Direct Testimony of Bruce N. Williams, Exhibit No. BNW-1T at 15:1-16:9.

> Among its jurisdictions, the company's most challenging is Washington, where the allowed ROE is the lowest at 9.5% and where it is contesting its last rate decision, while filing for a new base rate increase ($27 million request.)[13]

Similarly, Fitch has stated:

> Rate constructs in five of the six jurisdictions include power cost adjustments, the State of Washington being the exception.
>
> * * *
>
> [The Washington Commission] approved a $17 million electric rate increase based on a 9.5% return on equity (ROE) in December 2013…. The allowed return, in Fitch's opinion is lower than the sector average of around 10%.[14]

Q. Is Mr. Hill's comparison of expected pension returns and return on equity in this case a relevant comparison?

A. No. Among other reasons, there is no correlation in the underlying test periods and different factors inform the calculation of the returns. Pension accounting relies on conservative actuarial data, follows generally accepted accounting principles, and is based on the long-term nature of pension fund assets. The Commission has never used a pension return to corroborate a return on equity determination, despite the fact that Mr. Hill has made a similar argument in the past.[15]

Q. Please comment on Mr. Hill's statements that his overall ROR would support the Company's financial position.

A. Mr. Hill's analysis consists solely of a pre-tax interest coverage ratio and has the same deficiencies as Mr. Parcell's similar analysis.[16] These analytical flaws lead

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[13] Moody's Investors Service, May 7, 2014.

[14] Fitch Ratings, March 11, 2014.

[15] *See e.g. Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-090704, Testimony of Stephen C. Hill, Exhibit No. SGH-1T at 57 (Nov. 17, 2009).

[16] Confidential Testimony of Stephen C. Hill, Exhibit No. SGH-1CT at 58:14-19.

Mr. Hill to take the position that a lower overall ROR (7.32 percent) than currently authorized (7.36 percent) will result in an improved interest coverage ratio (3.28x) as compared to the Company's actual ratio (3.09x). On its face, this contention is not credible.

REPLY TO BOISE'S PROPOSED CAPITAL STRUCTURE

Q. What is Boise's proposed capital structure?

A. Like Staff and Public Counsel, Boise proposes a hypothetical capital structure containing a common equity component of 49.10 percent.

Q. How does Mr. Gorman support Boise's recommended hypothetical capital structure?

A. Mr. Gorman compares the adjusted debt ratio of different groups of electric utilities with the hypothetical capital structure and concludes that the hypothetical capital structure is reasonable.

Q. In testimony filed earlier this year in other states, did Mr. Gorman support the use of the Company's actual capital structure in setting its cost of capital?

A. Yes. In recent cases in Utah and Wyoming, Mr. Gorman testified in support of using the Company's actual capital structure to set rates. For example, in Wyoming Docket No. 20000-446-ER-14, Mr. Gorman proposed a capital structure containing 51.1 percent common equity.[17] Mr. Gorman supported this recommended capital structure as reflecting the Company's actual end-of-test-year capital structure.

[17] Docket No. 20000-446-ER-14, Non-Confidential Sur-Rebuttal Testimony of Michael P. Gorman, WIEC Exhibit No. 307 at 8 (Wy.P.S.C. Sept. 19, 2014).

Similarly, in Utah Docket No. 13-035-184, Mr. Gorman accepted[18] the Company's proposed capital structure, including a common equity component of 51.60 percent, which was the average of actual capitalization during the test period.[19]

Q. Please respond to Mr. Gorman's use of adjusted debt ratios as the exclusive basis for his capital structure recommendation.

A. Mr. Gorman's analysis of Standard & Poor's (S&P) adjusted debt ratios has three major problems. First, credit ratings are not established solely on one measure of capital structure, but on a multitude of items including financial metrics. The Commission has specifically observed that "ratings agencies consider a host of factors" when determining a company's credit rating, not just the equity ratio.[20]

Second, S&P does not currently rely on the credit metric that Mr. Gorman uses. In S&P's most recent overall summary of its rating methodology,[21] it lists seven cash flow/leverage analysis ratios—none of which are adjusted debt ratios.

Third, the data in Mr. Gorman's workpapers, which was the source of his adjusted debt ratio analysis, shows that the Company already has weaker credit ratios and metrics than either the A- or A rated groups of utilities that he cites.

[18] Utah Docket No. 13-035-184, Direct Testimony and Exhibits of Michael P. Gorman on behalf of the Federal Executive Agencies at 9 (Apr. 17, 2014).

[19] The Company subsequently reduced the common equity component to 51.43 percent to reflect financing activity completed after direct testimony was filed. The Utah and Wyoming cases used different test periods than this case, which accounts for the difference in the Company's actual capital structure between those cases and this case.

[20] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.* Dockets UG-040640 et al., Order 06 ¶ 35 (Feb. 18, 2005).

[21] Exhibit No. BNW-17, Standard & Poor's Ratings Direct Report, "Corporate Methodology: Ratios and Adjustments" (Nov. 19, 2013).

	Results for 2013					
	Return on Capital	EBIT Interest Coverage	EBITDA Interest Coverage	FFO/ Debt	Free oper. cash flow/debt	Debt/ EBITDA
PacifiCorp	7.1%	3.3x	4.8x	20.5%	6.8%	3.7x
S&P Corp. Credit Rating "A" Median	8.5%	3.95x	6.15x	24.1%	3.4%	3.35x
PacifiCorp ratio stronger or weaker?	**weaker**	**weaker**	**weaker**	**weaker**	**stronger**	**weaker**
PacifiCorp	7.1%	3.3x	4.8x	20.5%	6.8%	3.7x
S&P Corp. Credit Rating "A-" Median	8.3%	3.9x	5.6x	23.5%	-2.5%	3.5x
PacifiCorp ratio stronger or weaker?	**weaker**	**weaker**	**weaker**	**weaker**	**stronger**	**weaker**

Reducing the Company's common equity component and increasing its leverage will further weaken ratios that are already well below the respective peer group. Mr. Gorman's hypothesis that this will not have an impact on ratings is unrealistic. His statement that a reduction in the Company's common equity will likely not result in a reduction to its bond rating is inconsistent with the evidence drawn from his own data.

Q. Is there other evidence demonstrating that the Company cannot modify its capital structure to reduce its common equity ratio and continue to support its current bond ratings?

A. Yes. As I noted in direct testimony, a comparison to other Washington utilities regulated by this Commission demonstrates that a lower equity level directly corresponds to lower credit ratings.

	PacifiCorp	Avista	Puget Sound Energy
Common Equity %	51.7%	47.0%	48.0%
Sr. unsecured ratings (Moody's/S&P)	A3/A-	Baa1/BBB+	Baa1/BBB+

My direct testimony also shows the clear relationship between these lower common equity components and a higher cost of debt for the other Washington utilities.

	ACTUAL	CURRENTLY AUTHORIZED	
	PacifiCorp	Avista	Puget Sound Energy
Common Equity	51.73%	47.00%	48.00%
Cost of Long-Term Debt	5.19%	5.72%	6.16%

Q. Does Mr. Gorman compare overall RORs in his testimony?

A. No. As I discussed earlier, it is insufficient to look at just one component of the capital structure (such as common equity percentage) without considering the impacts on the other components, their respective costs, and the resulting overall ROR. Mr. Gorman does not include any analysis of how the Company's overall ROR compares to other utilities, rendering his analysis incomplete and limiting its value in this case.

Q. Is information on other utility RORs available in Mr. Gorman's workpapers?

A. Yes. Utility ROR data can be found in Mr. Gorman's workpapers,[22] and I have summarized it below:

[22] Exhibit No. BNW-19, Regulatory Research Associates, "Regulatory Focus, Major Rate Case Decisions—January–June 2014" (July 10, 2014).

Date	Company (State)	ROR %
2/20/2014	Consolidated Edison of New York (NY)	7.05%
2/26/2014	Northern States Power (ND)	7.45%
2/28/2014	Virginia Electric and Power (VA)	7.95%
3/14/2014	Liberty Utilities (NH)	7.92%
3/26/2014	Potomac Electric Power (DC)	7.65%
3/26/2014	Southwestern Public Service (NM)	8.26%
2014	**1st Quarter Average**	**7.71%**
4/2/2014	Delmarva Power & Light (DE)	7.26%
5/30/2014	Fitchburg Gas & Electric Light (MA)	8.28%
6/6/2014	Wisconsin Power and Light (WI)	7.90%
2014	**2nd Quarter Average**	**7.81%**

After Mr. Gorman filed testimony, RRA published their results for the third quarter of 2014, and I have added those below.

Date	Company (State)	ROR %
7/2/2014	Potomac Electric Power (MD)	7.61%
7/8/2014	Virginia Electric and Power (VA)	7.95%
7/23/2014	Rockland Electric (NJ)	7.83%
7/29/2014	Central Maine Power (ME)	7.06%
7/31/2014	Cheyenne Light, Fuel and Power (WY)	7.98%
8/20/2014	Atlantic City Electric (NJ)	7.75%
8/25/2014	Green Mountain Power (VT)	7.46%
8/29/2014	PacifiCorp (UT)	7.57%
9/24/2014	South Carolina Electric & Gas (SC)	8.53%
2014	**3rd Quarter Average**	**7.75%**
2014	**Year to Date Average**	**7.75%**

It is clear that the Company's proposed overall ROR of 7.67 percent is slightly below national utility averages.

Q. Mr. Gorman refers to a "Change in PacifiCorp's Dividend Plan." Will you please comment on this reference?

A. Yes. As my direct testimony and data request responses in this case make clear, the Company has not made any recent changes in its dividend plan. PacifiCorp began paying dividends to its parent company in 2011. The impact of these dividends has been included in the Company's proposed capital structure in this case and is a reason why the common equity percentage is approximately 50 basis points lower than the Company's actual common equity ratio in the 2013 general rate case.

Further Mr. Gorman's testimony about BHE's need for dividends to support acquisitions is pure speculation, with no evidentiary support and little relevance to this case. Mr. Gorman and I agree, however, that PacifiCorp's dividends are "reasonable."[23]

Q. Are there cost of capital items on which you and Mr. Gorman agree?

A. Yes. Mr. Gorman accepts the Company's proposed costs of short-term debt, preferred stock, and cost of long-term debt.[24] But like Mr. Parcell, the cost of long-term debt that Mr. Gorman accepts (5.19 percent), is the Company's proposed cost under its actual capital structure. Using Mr. Gorman's capital structure, the Company's debt cost would be 5.80 percent.[25]

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[23] Responsive Testimony of Michael P. Gorman, Exhibit No. MPG-1T at 12:24.

[24] Exhibit No. MPG-3 at 1. In addition, Mr. Gorman and I disagree about the cost of short-term debt if a hypothetical capital structure is used (1.73 percent versus 2.11 percent).

[25] Direct Testimony of Bruce N. Williams, Exhibit No. BNW-1T at 3.

Credit Metrics

Q. Please comment on Mr. Gorman's discussion concerning financial integrity and his credit metric analysis.

A. Mr. Gorman's analysis has several major flaws and cannot be relied upon to verify claims that his proposed ROR would support the Company's credit ratings.[26]

First, like the other witnesses, Mr. Gorman does not include any of the adjustments proposed by the other Boise witnesses. In total, the Boise witnesses are recommending a $2.7 million rate decrease in this case, the effect of which Mr. Gorman completely ignores in his analysis.[27] Similarly, Mr. Gorman's analysis assumes that the Company will actually earn its authorized ROR. As demonstrated in the testimony of Mr. R. Bryce Dalley, the Company has under-earned in Washington every year since at least 2006. Assuming similar under-earning prospectively further erodes the credit metrics calculated by Mr. Gorman.

Second, Mr. Gorman's model does not include any of the financing costs associated with construction work in progress (CWIP). The Company must finance the costs of assets while they are under construction and incurs interest expense on the debt portion of those financings. To compensate the Company, there is an allowance for funds used during construction (AFUDC) that is a non-cash offset to interest expense. As AFUDC is non-cash, it is not included in the rating agencies' determination of earnings before interest, taxes, depreciation and amortization

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[26] Mr. Gorman's conclusion that ratings would not change is unclear. Mr. Gorman argues that the ratios would support an "investment grade" bond rating (leaving open the possibility of a multi-step downgrade from the Company's current bond ratings). Mr. Gorman does not explicitly state that there would be no change to the Company's current bond ratings, implying a downgrade is certainly possible.

[27] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 6, Table 1.

(EBITDA) or funds from operations (FFO). However, the debt and corresponding interest costs on the financings are real and are included in the rating agencies' credit ratio analysis. Mr. Gorman's models have understated debt and interest expense and thereby produce erroneously high debt and interest coverage ratios.

Third, Mr. Gorman's analysis does not include the full amount of adjustments that S&P makes when it assesses the Company's creditworthiness. The result is that Mr. Gorman has included less than one-half of the amount of S&P's debt adjustments.

Fourth, Mr. Gorman does not test his proposed ROR against five of the seven ratios for which S&P publishes targets as part of its quantitative analysis.

Q. Which specific rating agency adjustments does Mr. Gorman omit from his analysis?

A. Mr. Gorman does not include the following adjustments and thus ignores the corresponding amount of increased debt as of December 31, 2013:[28] (1) Asset Retirement Obligations (AROs)—$89.7 million; (2) Post-retirement employee benefits—$111.15 million; (3) Accrued Interest—$110.0 million. Each of these adjustments and the respective amounts are documented on S&P's website, a print-out of which is attached as Exhibit No. BNW-18. As shown in that exhibit, Mr. Gorman has correctly included S&P's adjustments related to operating leases and purchased power agreements, but omitted the balance of S&P's debt adjustments.

[28] For purposes of this rebuttal testimony, I am focusing on the more significant adjustments and ignoring the adjustment related to preferred stock due to the immaterial amount that remains outstanding.

Q. Has S&P stated explicitly that they include the three adjustments that Mr. Gorman's analysis omits?

A. Yes. In addition to the evidence of how S&P specifically reviews the Company's credit rating, S&P is very clear about generally viewing these items as debt. For instance, S&P states the following:

- AROs—"We treat AROs as debt-like obligations…."[29]
- Post-retirement employee benefits—"We include underfunded defined-benefit obligations for retirees, including pensions and health care coverage (collectively, postretirement benefits or PRB) in our measure of debt."[30]
- Accrued Interest—"We reclassify as debt any accrued interest that is not already included in reported debt."[31]

Q. Does Mr. Gorman's analysis provide a benchmark comparison for all seven of S&P's cash flow/leverage ratios?

A. No. Mr. Gorman's analysis provides results for only two of the seven ratios.[32] He ignored the five other ratios that S&P uses to help assess interest coverage and debt payback.

For all of these reasons, the Commission should not rely on Mr. Gorman's credit metrics analysis. Mr. Gorman's conclusion that his proposed overall ROR will produce financial results that support the Company's credit ratings is unsubstantiated.

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[29] Exhibit No. BNW-17 at 12.
[30] *Id.* at 25.
[31] *Id.* at 7.
[32] Exhibit No. BNW-20, Standard & Poor's Ratings Direct Report, "Corporate Methodology" (Nov. 19, 2013) at 35 - Table 18.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit No. BNW-17
Docket UE-140762 *et al.*
Witness: Bruce N. Williams

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF BRUCE N. WILLIAMS

Standard & Poor's Ratings Direct Report, "Corporate Methodology: Ratios and Adjustments" (November 19, 2013)

November 2014

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Corporate Methodology: Ratios And Adjustments

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Criteria | Corporates | General:

Corporate Methodology: Ratios And Adjustments

*(**Editor's Note:** We originally published this criteria article on Nov. 19, 2013. We republished this article on Oct. 31, 2014, to clarify a term in paragraph 104. We republished this article following our periodic review completed on Oct. 16, 2014. We republished this article to add a section on frequently asked questions. We republished this article on April 10, 2014, to correct the first bullet point in paragraph 174 regarding the lease disclosure requirements under International Financial Reporting Standards, and the second bullet point in the same paragraph to add that CFO, as well as FFO, are increased by adding back the depreciation expense. These corrections have no impact on our ratings.)*

1. Standard & Poor's Ratings Services is updating its criteria for making analytical adjustments to companies' financial data, following its "Request for Comment: Corporate Criteria: Ratios And Adjustments," published on June 26, 2013, on RatingsDirect. This criteria update relates to our global corporate criteria "Corporate Methodology," published on Nov. 19, 2013, and to the criteria article "Principles Of Credit Ratings," published on Feb. 16, 2011.

2. This criteria article supersedes "2008 Corporate Criteria: Ratios And Adjustments," published on April 15, 2008, and other articles, as listed in the Appendix.

I. SCOPE OF THE CRITERIA

3. These criteria apply to nonfinancial corporate entities we rate globally. It excludes project finance entities and corporate securitizations because of their unique characteristics.

II. SUMMARY OF THE CRITERIA

4. The analytical adjustments that Standard & Poor's makes to the reported financial results of companies worldwide allow for globally consistent and comparable financial data.

5. These adjustments also enable better alignment of a company's reported figures with our view of underlying economic conditions. Moreover, they allow a more accurate portrayal of a company's ongoing business, for example, following acquisitions or disposals, through pro forma adjustments.

6. There are general analytical adjustments that apply across multiple industries, but some are industry specific. The general adjustments are described in this criteria article, whereas the details of industry-specific adjustments are in the relevant criteria articles, labeled "Key Credit Factors."

III. IMPACT ON OUTSTANDING RATINGS

7. The impact of the new corporate criteria on ratings is described in the criteria article "Corporate Methodology," published on Nov. 19, 2013.

IV. EFFECTIVE DATE AND TRANSITION

8. These criteria are effective immediately.

V. METHODOLOGY AND ASSUMPTIONS

A. Reasons For Analytical Adjustments

9. A company's financial statements are the starting point of our financial analysis. Our analysis of a company's financial statements begins with a review of the accounting features to determine whether the data in the statements accurately measure a company's performance and position relative to that of its peers and the larger universe of corporate entities.

10. Understanding accounting frameworks such as International Financial Reporting Standards (IFRS), U.S. generally accepted accounting principles (U.S. GAAP), and other local or statutory GAAP, is therefore crucial to our corporate rating methodology. It is equally important to understand the differences between the accounting standards and how those differences can affect the reporting of economically equivalent transactions.

11. Accounting rules often provide options for the treatment of certain items, making the comparison of data difficult, even among companies using the same accounting frameworks. Moreover, business transactions have become increasingly complex, and so have the related accounting rules and concepts, which often involve greater reliance on subjective estimates and judgments.

12. In addition, several fundamental shortcomings of reporting requirements could reduce the quality and quantity of information in financial statements. One example relates to recognition and measurement: What circumstances determine whether an item such as a special-purpose entity or a synthetic lease should be reflected on or off a company's balance sheet, and at what value? Another example concerns transparency: What should a company disclose about the nature of off-balance-sheet commitments, compensation arrangements, or related-party transactions?

13. To allow for globally consistent and comparable financial analyses, our rating analysis includes quantitative adjustments to companies' reported results. These adjustments also enable better alignment of a company's reported figures with our view of underlying economic conditions. Moreover, they allow a more accurate portrayal of a company's ongoing business, for example following acquisitions or disposals, through pro forma adjustments.

14. Although our adjustments revise certain amounts that companies report under applicable accounting principles, this does not imply that we challenge the company's application of those principles, the adequacy of its audit or financial reporting process, or the appropriateness of the accounting judgments made to fairly depict the company's financial position and results for other purposes.

15. Rather, the methodology seeks to address a fundamental difference between accounting and analysis. An accountant

puts figures together in the form of financial statements. An analyst, by definition, picks the numbers apart and considers the implications of their components as well as the reported totals. It is rarely possible to completely recast a company's financial statements (so we do not attempt to apply double-entry accounting), but adjustments improve the relevance and consistency of the financial ratios we use in our analysis.

B. How And When Adjustments Apply

16. Certain adjustments pertain broadly to all industries because they apply to many types of companies at all times. These include adjustments for operating leases and postretirement employee benefits. Other adjustments may pertain only to a certain industry. Industry-specific adjustments are in the relevant criteria articles labeled Key Credit Factors.

17. In rare circumstances, consistent with the principles underpinning our explicit adjustments, we may make nonstandard analytical adjustments to depict a transaction differently from the reported financial statements or simply to increase the comparability of financial data across industries. For example, we may treat certain cash-raising transactions as akin to borrowing if they do not follow the standard trade terms of an industry and are in lieu of conventional debt issuance.

18. Our use of analytical adjustments depends on whether events and items a company reports could have a material impact on our view of the company's creditworthiness. Therefore, we may not make certain adjustments if the related amounts are too small to be material to our analysis.

19. Additionally, the transparency or extent of a company's disclosure in its financial statements may preclude adjustments to reported figures. For example, in many industries there is insufficient disclosure to allow full adjustments to income for inventory figures that reflect the "last in first out" valuation method.

C. Adjusted Debt Principle

20. Many of the analytical adjustments we make result from our view of certain implicit financing arrangements as being debt-like. Our depiction of these transactions as debt, which is often contrary to how a company reports them, affects not only the quantification of debt but also the measures of earnings and cash flows we use in our analysis. Therefore, it is instructive to understand the principles underpinning our adjustments to debt.

21. In general, items that we add to reported debt include:

- Incurred liabilities that provide no future offsetting operating benefit (such as unfunded postretirement employee benefits and self-insurance reserves);
- On- and off-balance-sheet commitments for the purchase or use of long-life assets (such as lease obligations) or businesses (such as deferred purchase consideration) where the benefits of ownership are accruing to the company; and
- Amounts relating to certain instances when a company accelerates the monetization of assets in lieu of borrowing (such as through securitization or factoring of accounts receivable).

22. Many of the items that increase debt under the adjustments are probable future calls on cash, but not all future calls on

cash are forms of debt. We do not consider a company's future commitments to purchase goods or services it has not received as akin to debt. This is because these are executory contracts, which means a counterparty must still perform an action and the benefits of ownership have yet to accrue to the company.

23. Not all incurred liabilities are added to reported debt. The adjusted debt figure excludes short-term obligations, such as accounts payable and other accrued liabilities, because we regard them as trade credit rather than the incurrence of long-term debt. However, to the extent that a company defers payment beyond the term customary for its supply chain, we may add that amount to debt.

24. Additionally, we may exclude certain obligations a company reports as debt. This is, for example, because we perceive those obligations as equity rather than debt.

25. Companies' recognition and measurement of the numerous financing mechanisms vary. Some are reported at amortized cost (for example, issued debt), others at fair value (such as for contingent consideration), and others somewhere in between (as for pension obligations). Companies may also exclude certain financing from the balance sheet (such as operating leases). Ideally, we add to reported debt the amounts that approximate the amortized cost of commitments we consider to represent a debt, although from a practical standpoint this is not always possible.

26. Lastly, we may reduce the adjusted debt figure by netting surplus cash (see paragraphs 231-238).

D. Financial Ratios

27. The components of our ratios are derived from figures in companies' financial statements, subject to adjustments (subsequently referred to as "all applicable adjustments") defined in this criteria article and in the applicable Key Credit Factors articles. The definitions of the components are in the glossary (see paragraphs 248-263).

E. Analytical Adjustments

28. To calculate our financial ratios, we may make analytical adjustments related to the following:

- 1. Adjusted debt and interest

a) Accrued interest and dividends

b) Debt issuance costs

c) Debt at fair value

d) Fair-value hedging

e) Convertible debt

f) Foreign currency hedges of debt principal

g) Initial measurement of debt

- 2. Asset-retirement obligations
- 3. Capitalized development costs
- 4. Capitalized interest
- 5. Financial and performance guarantees
- 6. Hybrid capital instruments
- 7. Inventory accounting methods
- 8. Litigation
- 9. Multi-employer pension plans
- 10. Nonoperating activities and nonrecurring items
- 11. Leases
- 12. Postretirement employee benefits and deferred compensation
- 13. Scope of consolidation
- 14. Securitization and factoring
- 15. Seller-provided financing
- 16. Share-based compensation expenses
- 17. Surplus cash
- 18. Workers' compensation and self-insurance

1. Adjusted debt and interest

29. In reflecting reported debt in our metrics, our objective is to use an amortized cost method, consistent with the amortized cost method under accounting standards like IFRS and U.S. GAAP. This method reflects debt as the amount of the original proceeds, plus interest calculated using the effective interest rate, minus payments of principal and interest. The effective interest rate is equivalent to the yield to maturity of a bond and takes into account the compounding of interest. This rate is consistent over the term of a fixed-rate debt instrument. For variable-rate debt, the effective interest rate after issuance will vary each time the coupon rate is reset. Under the amortized cost method, interest expense is measured at the full cost of the borrowing.

30. However, companies do not always report debt in this manner. Several factors can distort the measurement of debt, such as the exclusion of accrued and unpaid interest, the inclusion of debt-issuance costs, reporting debt at fair value, applying fair-value hedge accounting, and the method of accounting for convertible instruments. The use of different measures for debt may also result in interest expense amounts that differ from those under the amortized cost method. We make adjustments to the measurement of reported debt and interest in certain circumstances as described in paragraphs 31 to 70.

a) Accrued interest and dividends

31. We reclassify as debt any accrued interest that is not already included in reported debt. This adjustment enables a more consistent comparison among companies' financial obligations, by eliminating the disparity arising from differences in the frequency of interest payments (for example, quarterly rather than annually) or in payment due dates (for example, Jan. 1 or Dec. 31).

32. Additionally, we treat accrued interest or dividends on hybrid securities as debt. Deferred cumulative interest--whether the deferral was optional or mandatory--is also treated as debt.

Adjustment procedures

33. Data requirements:

- Reported accrued interest on debt, and dividends on hybrid securities, as of the balance-sheet date.

34. Calculations:

- Debt: Add to reported debt any accrued interest on debt and any dividends on hybrid securities.

b) Debt issuance costs

35. Debt issuance costs are a form of prepaid interest, which companies record on the balance sheet and amortize as an interest expense over the term of the debt. We regard them as part of the total cost of borrowing and therefore do not deduct the amortization of debt issuance costs from reported interest.

36. However, there are different approaches to where these amounts are reported on the balance sheet. A company may either report debt issuance costs as a separate asset, or deduct them from reported debt as a "contra liability" (that is, a liability with a debit balance, rather than the typical credit balance). We look to exclude these prepaid amounts from debt, when reported as a contra liability, to attain comparability. Similarly, if a company deducts premiums paid for modifications or redemptions from debt, we exclude those amounts from debt if practicable.

Adjustment procedures

37. Data requirements:

- Amount of debt issuance costs or modification premiums reported as a contra liability, which reduces reported debt.

38. Calculations:

- Debt: Add to reported debt the amount of debt issuance costs or modification premiums reported as a contra liability.

c) Debt at fair value

39. In certain circumstances, a company may report debt at fair value instead of at amortized cost. In such cases, we adjust the reported figure to reflect the amortized cost method. If the amortized cost figure is not shown in the financial statements, we may estimate it, based on the amount originally received or the face value plus accrued but unpaid interest.

40. In addition, we seek to exclude gains or losses from the revaluation of debt at fair value from our measure of interest expense. However, from a practical standpoint, if a company does not disclose these figures, it is difficult to adjust interest expense for the difference between the reported figure and the effective rate achieved by the amortized cost method.

41. When this difference is material, we may make estimates to arrive at a figure that approximates interest expense, exclusive of mark-to-market effects. We would make such an estimate by, for example, multiplying the face value of the obligation by an interest rate estimated from other similar debt instruments.

Adjustment procedures

42. Data requirements:

- The amount of debt using the amortized cost method (from the financial statements) or, if this is not available, an estimate based on the amount originally received or the face value plus accrued but unpaid interest.
- The amount of any charge or benefit for debt reported at fair value and recorded as an interest expense.

43. Calculations:

- Debt: Increase or decrease reported debt by the difference between the reported amount and our estimate of the amortized cost.
- Interest expense: Increase or decrease reported interest expense by the amount of any charge or benefit for debt reported at fair value and recorded as an interest expense.

d) Fair-value hedging

44. A company may issue fixed-rate debt and at the same time enter a derivative contract to synthetically create a variable-rate debt instrument. If all necessary conditions are met, companies may elect to apply fair-value hedge accounting to such an arrangement. The effect of this accounting approach is that a company would report both the derivative instrument and the debt (but only the risk being hedged) at fair value. Changes in the fair values of both items from one reporting date to the next are netted off against each other in the income statement.

45. When a company applies fair-value hedge accounting to debt, we adjust the reported debt figure to reflect the amortized cost method.

46. It is not necessary to adjust interest expense in this case because the fair-value adjustments the company makes in the income statement generally offset each other, and settlements under the derivative are reported as an interest expense.

Adjustment procedures

47. Data requirements:

- The debt figure expressed as the amortized cost amount in the financial statements.
- If this is not available, we (1) determine the amount of the fair-value adjustment made to reported debt as a consequence of hedge accounting; or (2) estimate the adjustment amount using the fair value of the related derivative instrument; or (3) adjust debt to reflect the amount originally received as proceeds or the face value plus accrued and unpaid interest.

48. Calculations:

- Debt: Increase or decrease debt by the difference between the reported amount and our estimate of debt under the amortized cost method.

e) Convertible debt

49. Due to their complex nature, we take a slightly different approach to measuring convertible debt instruments that give the holder the option of converting the debt into shares. Because of this option, the coupon rate on such obligations is normally lower than market interest rates.

50. Under U.S. GAAP and IFRS the value of a convertible debt obligation is split into a debt component and an equity

component (following the split-accounting method).

51. The debt component is the fair value of a similar debt obligation without the conversion feature. This amount is accounted for under the amortized cost method and increases toward the face value of the convertible debt instrument until maturity or conversion.

52. The equity component (the value of the conversion feature) represents the difference between the debt component and the issue price of the convertible debt instrument. The value of the equity portion remains constant.

53. Although uncommon, we may regard a convertible debt instrument as having equity content in our analysis, depending on its terms and conditions and our view of the likelihood that the debt holder will convert it to equity (see "Hybrid Capital Handbook: September 2008 Edition," published on Sept. 15, 2008). If we consider such an instrument to have high equity content, we reclassify it as equity. If we consider that there is minimal equity content, we treat the instrument fully as debt.

54. We typically add to reported debt the unamortized value of the discount created by the conversion option, bringing the value of such an instrument back to par.

55. In our ratios, we seek to include the full effective cost of the obligation as interest. We believe the interest resulting from the split-accounting method achieves this goal and therefore no adjustment is necessary.

56. If a company does not use split accounting we estimate the cost of debt by increasing reported interest expense when the difference in value under the other method is material.

Adjustment procedures

57. Data requirements:

- The face value of convertible debt instruments or the remaining unamortized discount as of the balance-sheet date.
- The amount of interest expense reported in the period, if we consider the instruments to have high equity content.

58. Calculations:

- Debt: Increase reported debt by the amount necessary to bring an instrument back to par. If an instrument has high equity content according to our criteria, we deduct the reported amount from debt.
- Interest: Subtract from interest the amount of interest expense on convertible debt considered to have high equity content.

f) Foreign currency hedges of debt principal

59. Foreign-currency-denominated debt is typically included in consolidated debt on the balance sheet at the amount of foreign currency, translated at the spot rate on the balance-sheet date.

60. Many companies hedge the foreign currency exposure by entering into derivatives that fix the foreign exchange rate that will apply on the debt's repayment date. To better reflect the economics of such transactions, we adjust the reported amount of foreign-currency-denominated debt to reflect the net amount required for repayment as a result of the hedge.

61. We may not make this adjustment if other factors can neutralize the benefit of the derivative. These factors include

concerns about risk relating to the derivative counterparty (such as when a derivative counterparty has credit quality equivalent to 'BB+' or lower) and other derivative contracts that can offset the benefit of the derivative hedge.

62. The adjustment amount results from restating the hedged debt principal using the "locked-in" foreign exchange rate achieved through the derivative. The adjustment amount is broadly equivalent to the fair value of a derivative representing a foreign currency hedge of debt principal, but may differ for various reasons, such as because the derivative's fair value also reflects liquidity and counterparty risk.

63. We use the derivative's value as a proxy for our adjustment amount if retranslation of the debt balance is not practical because of insufficient information.

64. However, companies often hedge the foreign currency exposure related to debt principal and interest simultaneously. In this instance, we take care to adjust only for the fair value of the derivative that hedges the principal, and not the portion that hedges the interest.

Adjustment procedures

65. Data requirements:

- The amount of hedged foreign-currency-denominated debt (from the balance sheet); and
- The locked-in foreign exchange rate (or locked-in principal value of outstanding debt) achieved via the hedge transaction.
- Alternatively, the fair value of the derivative that applies only to the principal (that is, excluding any fair value associated with hedged interest payments).

66. Calculations:

- Debt: Retranslate foreign-currency-denominated debt using the locked-in foreign exchange rate (or adjust the balance-sheet value of debt to equal the locked-in principal value). Alternatively, add to or subtract from reported debt the fair value of the hedging instrument on the balance-sheet date.

g) Initial measurement of debt

67. We subscribe to amortized cost as the preferred method of measuring debt after debt is issued. However, in certain circumstances, we may take an alternative view toward a company's initial measurement, and therefore ongoing measurement, of a particular debt instrument, as described in the next paragraph.

68. Companies usually initially measure debt at an amount equal to the net proceeds received at issuance. However, there are other methods of initial measurement of debt that we believe can in certain instances distort the initial and ongoing carrying value of debt. This may include the methods applied to debt assumed in an acquisition, or debt that has been modified or is part of a distressed exchange. When our judgment about the initial measurement (and therefore ongoing measurement) of a debt instrument differs from a company's, we may adjust debt, funds from operations (FFO), and interest expense if practical and the effect is material.

Adjustment procedures

69. Data requirements:

- Initial measurement of the applicable debt instrument.

- Our assumed measurement of the applicable debt instrument.
- Interest expense associated with the applicable debt instrument that is reported during the period.
- Interest expense for the period, based on our assumed initial measurement of the applicable debt instrument.

70. Calculations:

- Debt: Increase or decrease debt by the difference between the reported amount of debt and our estimate of amortized cost based on our assumed initial measurement.
- Interest expense: Increase or decrease interest expense by the difference between reported interest expense and the estimated interest expense based on our assumed initial measurement.
- FFO: Increase or decrease FFO by the difference between reported interest expense and the estimated interest expense based on our assumed initial measurement.

2. Asset-retirement obligations

71. Asset-retirement obligations (AROs) are legal obligations associated with a company's retirement of tangible long-term assets. Examples of AROs include the cost of plugging and dismantling oil and gas wells, decommissioning nuclear power plants, and treating or storing spent nuclear fuel and capping and restoring mining and waste-disposal sites.

72. We treat AROs as debt-like obligations, although several characteristics distinguish them from conventional debt, including timing and measurement uncertainties.

73. A company's liability for AROs is independent from the amount and timing of the cash flows the associated assets generate. In certain situations, companies fund AROs by adding a surcharge to customer prices; or the AROs are paid by third parties, such as a state-related body. In these cases there would typically be no debt adjustment.

74. The measurement of AROs involves a subjective assessment and is therefore imprecise. We generally use the reported ARO figures, but we may make adjustments for anticipated reimbursements, asset-salvage value, or any of the company's assumptions we view as unrealistic. Those assumptions may include the ultimate cost of abandoning an asset, the timing of asset retirement, and the discount rate used to calculate the balance-sheet value.

75. Under most accounting standards, company balance sheets show the ARO figure before tax, and any expected tax benefits as a separate deferred tax asset on the balance sheet (because the associated ARO-related asset is subject to depreciation). Tax savings that coincide with settling ARO payments (as opposed to their provisioning), reduce the cash cost of the AROs, and we factor them into our analysis to the extent that we expect the company to generate taxable income in the same tax jurisdiction.

76. Our approach is to add AROs--after deducting any dedicated retirement-fund assets or provisions, salvage value, and anticipated tax savings--to debt. We generally adjust for the net aggregate funding position, even if some specific obligations are underfunded and others are overfunded. The adjustment amounts are tax effected (that is, adjusted for any tax benefit the company may receive) if the company will likely be able to use tax deductions.

77. The accretion of an ARO that reflects the time value of money is akin to noncash interest and similar to postretirement benefit interest charges. Accordingly, we reclassify the accretion (net of earnings on any dedicated funds), using a floor of zero for the net amount as interest expense, in analyzing the income and cash flow statements.

78. If dedicated funding is in place and the related returns are not entirely reflected in reported earnings and cash flows,

we add the unrecognized portion of the related returns to earnings and cash flows. We reclassify the recognized portion to interest expense and cash flow from operations (CFO).

79. We treat cash payments for the abandonment of assets and contributions to dedicated funds that exceed ARO interest costs (after deducting ARO fund earnings) as repayment of the ARO. We therefore add these amounts to FFO and CFO.

80. We treat cash payments for the abandonment of assets and contributions to dedicated funds that are less than the ARO interest costs (after deducting ARO fund earnings) as the incurrence of a debt obligation. We therefore deduct the shortfall in payments from FFO and CFO.

Adjustment procedures

81. Data requirements:

- The ARO figure (from the financial statements or Standard & Poor's estimate).
- Any associated assets or funds set aside for AROs.
- ARO interest costs irrespective of whether charged to operating or financing costs.
- The reported gain or loss on assets set aside for funding AROs.
- Any cash payments for AROs.

82. Calculations:

- Debt: Add net ARO to debt (net ARO equals the reported or estimated ARO minus any assets set aside to fund AROs, multiplied by 1 minus the tax rate).
- EBITDA: Add ARO interest costs included in operating costs.
- Interest: Deduct ARO interest costs (net of ARO fund earnings) from reported operating expenses, if included there, and add to interest expense.
- FFO: Our definition of FFO is EBITDA minus net interest expense minus current tax expense, after adjusting each of the three components according to our criteria. EBITDA and interest expense are adjusted as described in the previous two bullet points. The figure to adjust the current tax expense results from multiplying the applicable tax rate by the net result of (1) new provisions, plus (2) interest costs, minus (3) the actual return on funded assets, minus (4) fund contributions or ARO payments in the corresponding period. The net effect of these adjustments is that FFO is reduced by net ARO interest and adjusted for tax effects.
- CFO: Subtract the gain (or add the loss) on assets set aside for AROs from interest expense. Then compare the resulting amount with payments on the AROs to arrive at the excess contribution or shortfall to add to, or subtract from, CFO. Additionally, we adjust CFO for tax effects in a similar way as for FFO.

3. Capitalized development costs

83. In financial reporting, research costs are almost universally treated as an expense; however the treatment of development costs varies. U.S. GAAP, with limited exceptions (such as for software development costs in certain instances), requires companies to treat development costs as an expense, whereas IFRS allows such costs to be capitalized under certain conditions. In addition to these differences between accounting regimes, there is an element of subjectivity in determining when development costs are capitalized, which can lead to a disparity among companies' reported figures.

84. To enhance the comparability of data, we adjust reported financial statements when a company capitalizes

development costs, if the information is available and the amounts material. The adjustment aims to treat the capitalized development costs as if they had been expensed in the period incurred.

85. We aim to adjust EBITDA, FFO, and CFO for the amount of development costs capitalized during the year. This is because a company's position in its product life cycle has a great effect on its current spending relative to the amortization of previously capitalized development costs. However, in the absence of accurate figures, we use the annual amortization figure reported in the financial statements as a proxy for the current year's development costs. To the extent that the amortization of previously capitalized costs equals current development spending, there is no impact on operating expenses and EBIT because these amounts are after amortization. However, there is an impact on EBITDA, FFO, and CFO, which are calculated before amortization.

86. We do not carry through the adjustment to the cumulative asset (and equity) accounts, weighing the complexity of such adjustments against their typically limited impact on amounts that are secondary to our analysis.

87. We make one exception to this approach, and that is for capitalized development costs relating to internal-use software. Consistent with our goal of achieving comparability, we do not want to create a gap between companies that develop software for internal use and those that purchase software and capitalize equivalent products. We therefore attempt to exclude such costs from our adjustment.

Adjustment procedures

88. Data requirements:

- Amount of development costs incurred and capitalized during the period, excluding, if practical, capitalized development costs for internal-use software.
- Amortization amount for relevant capitalized costs.

89. Calculations:

- EBITDA, FFO, and CFO: Subtract the amount of net capitalized development costs or, alternatively, the amortization amount for that period.
- EBIT: Subtract (or add) the difference between the spending and amortization in the period.
- Capital expenditures: Subtract the amount capitalized in the period.

4. Capitalized interest

90. Under most major accounting regimes, financial statements show interest costs related to the construction of fixed assets as capitalized, that is, as a component of the historical cost of capital assets. This can obscure the total interest that has been incurred during the period, hindering comparisons of the interest burden of companies that capitalize and do not capitalize interest.

91. Under our methodology, interest costs that have been capitalized are adjusted and included as interest expense in the period in which the interest was incurred.

92. In the statement of cash flows, we reclassify any capitalized interest shown as an investing cash flow to operating cash flow. This adjustment reduces CFO and capital expenditures by the amount of interest capitalized in the period. Free operating cash flow remains unchanged.

93. We make no adjustment for the cumulative effect on the value of property, plant, and equipment resulting from any prior-year interest capitalization, tax effects, or depreciation, due to disclosure limitations and the minimal analytical benefit this would provide.

Adjustment procedures

94. Data requirements:

- The amount of capitalized interest during the period.

95. Calculations:

- Interest expense: Add amount of interest capitalized during the period.
- FFO: Our definition of FFO is EBITDA minus net interest expense minus current tax expense, after adjusting each of the three components according to our criteria. Net interest expense includes the interest capitalized during the period, as described in the previous bullet point. Therefore, FFO is reduced by the amount of interest capitalized in the period.
- CFO: Subtract the amount of capitalized interest recorded as an investing cash flow.
- Capital expenditures: Subtract the amount of capitalized interest recorded as an investing cash flow.

5. Financial and performance guarantees

a) Financial guarantees

96. A financial guarantee is a promise by one party to assume a liability of another party if that party fails to meet its obligations under the liability. A guarantee can be limited or unlimited. If a company has guaranteed liabilities of a third party or an unconsolidated affiliate, we may add the guaranteed amount to the company's reported debt.

97. We do not add the guaranteed amount to debt if the other party is sufficiently creditworthy (that is if the other party has credit quality equivalent to 'BBB-' or higher) in its own right, or we believe that the net amount payable if the guarantee were called would be lower than the guaranteed amount. This could happen, for example, if the company that has provided the guarantee has been counter-guaranteed by another party. In this case, we add the lower amount to debt. We do not adjust interest expense because the guarantor is only obliged to service interest if called upon to meet the guarantee.

b) Performance guarantees

98. A performance guarantee is a promise to provide compensation if a company does not complete a project or deliver a product or service according to the agreed terms. An insurance company or bank may issue such guarantees on a company's behalf. Construction companies often provide performance guarantees to meet a condition in a work contract. If the project, product, or service is not completed as agreed, the customer can call on the performance guarantee.

99. We do not regard performance guarantees as debt if a company is likely to maintain sufficient work or product quality to avoid making large payments under those guarantees.

100. A company's past record of payments under performance guarantees could indicate the likelihood of future payments under such guarantees. Only if this payment history suggests a high likelihood of future payments would we estimate a potential liability and add that amount to debt.

Adjustment procedures

101. Data requirements:

- The value of guarantees on and off the balance sheet, net of any tax benefit.

102. Calculations:

- Debt: Add to debt the amount of on- and off-balance-sheet debt-equivalent related to guarantees, net of any tax benefit.
- Equity: Subtract from equity the amount of off-balance-sheet debt-equivalent related to guarantees, net of any tax benefit.

6. Hybrid capital instruments

103. Hybrid capital instruments (or hybrids) have features of both debt and common equity. We classify a corporate hybrid as having minimal, intermediate, or high equity content depending on the specific terms and conditions of the instrument and our view of whether the issuer intends to maintain the instrument as loss-bearing capital. Our classification of equity content determines the type of adjustments we make to a company's reported figures.

104. A company's issuance of conventional hybrids, in an aggregate amount of up to 15% of capitalization, can be eligible for equity credit, which means that we exclude at least some of the hybrid instrument and its interest costs from our debt and interest measures (see "Hybrid Capital Handbook: September 2008 Edition," published on Sept. 15, 2008). We exclude bonds that are mandatorily convertible into shares from this calculation. Capitalization is equal to balance-sheet equity, plus debt and hybrids, after adjusting for goodwill and making all applicable adjustments. The capitalization calculation excludes any goodwill asset that exceeds 10% of total assets.

105. The treatment of hybrids for the purposes of our leverage and debt service ratio calculations depends on the equity content classification:

- Hybrids that have high equity content are treated as equity and the interest or dividends are treated as dividends.
- For hybrids with intermediate equity content, 50% of the principal is treated as debt and 50% as equity (excluding unpaid accrued interest or dividends, which are added to debt). Similarly, we treat one-half of the period's interest or dividends as dividends and one-half as interest. There is no adjustment to related taxes.
- Hybrids with minimal equity content are treated entirely as debt and all interest or dividends as interest.

106. In all cases, accrued coupon payments are treated as debt.

107. The criteria for adjustments related to convertible debt are in paragraphs 49-58 of this article and in "Hybrid Capital Handbook: September 2008 Edition," published on Sept. 15, 2008.

Adjustment procedures

108. Data requirements:

- Documentation for reported hybrid capital instruments.
- Amount of hybrids, debt, goodwill, and shareholders' equity on the balance sheet.
- Amount of associated interest or dividend expense and interest or dividend payments in the period.
- Amount of accrued unpaid interest or dividends.

109. Calculations:

- Hybrids reported as equity: (1) If we classify equity content as high, there is no adjustment to equity. (2) If we classify equity content as intermediate we deduct 50% of the value from equity and add it to debt. We also deduct 50% of the dividend accrued during the accounting period and add it to interest expense, thereby reducing FFO. Likewise, 50% of any dividends paid are deducted from CFO. (3) If we classify equity content as minimal, we deduct the full principal amount from equity and add it to debt. We add associated dividends to interest expense, thereby reducing FFO. Likewise dividends paid are added to interest paid, thereby reducing CFO.
- Hybrids reported as debt: (1) We deduct the value of hybrids with high equity content from debt and add it to equity. We also deduct the associated interest charge from interest expense and add it to dividends, thereby removing it from FFO. Likewise, interest paid is added to CFO and dividends. (2) If we classify equity content as intermediate, we deduct 50% of its value from debt and add it to equity. We also deduct 50% of the associated interest expense from interest expense and add it to dividends accrued, thereby increasing FFO. 50% of interest paid is added to CFO. (3) If equity content is minimal there is no adjustment because we treat such hybrids as debt.
- Debt: We add to debt the accrued and unpaid interest and dividends on all hybrids.

7. Inventory accounting methods

110. Accounting frameworks allow companies a choice of inventory accounting method, and this leads to reporting differences within industries and among regions. The disparity is more pronounced in inventory-intensive industries, particularly when the price of inventory (such as raw materials) fluctuates significantly. This is because the method a company uses influences the amount of inventory it can charge as an expense, and therefore also its taxable income. The inventory accounting methods under U.S. GAAP are "first in first out" (FIFO), "last in first out" (LIFO), weighted-average cost, and specific identification.

111. Similar costing methods exist in other generally accepted accounting principles. However, many frameworks, including IFRS, do not allow LIFO. The tax treatment is a key factor in a company's choice of inventory costing method and it varies significantly by jurisdiction. For example, LIFO is permitted for tax-reporting purposes in the U.S., and a company that uses it for tax purposes must also use it for preparing its financial statements.

112. The greatest potential disparity in financial results comes from using FIFO as opposed to LIFO. When inventory prices are rising, the LIFO method results in lower income than under FIFO because the most recent and higher cost of goods is transferred to the income statement, while the remaining inventory is shown at the older, lower cost on the balance sheet. Furthermore, LIFO results in improved cash flows for that period because income taxes are lower as a result of the lower taxable income.

113. Apart from hindering comparison between different companies, the different methods can also obscure a company's true performance record. For example, LIFO arguably allows for a more realistic depiction of current costs on the income statement, but showing inventory at older costs distorts the balance-sheet position. The FIFO method, on the other hand, provides a more up-to-date valuation of inventory on the balance sheet, but can significantly understate the cost of goods sold during a period of rising prices and overstate income.

114. We adjust the reported inventory figures if material to our analytical process. Companies that use LIFO have to disclose what the inventory valuation would be under FIFO, through an account called the LIFO reserve that represents the cumulative effect on gross profit from the use of the LIFO method. For such companies, we add the

balance in the LIFO reserve to the reported inventory. This enables us to reflect inventory balances at approximately the current market value. A corresponding adjustment, net of tax, is made to equity.

115. We do not adjust the income statement when a company uses LIFO because we believe the LIFO method results in costs of goods sold that closely reflect replacement-cost values.

116. Typically, there are no adjustments to the income statement for companies that use FIFO or the average cost method because the data are generally not available.

117. When a company using the LIFO method has inventory balances that decrease over a period of time, LIFO liquidation may result. This means that older layers of inventory are turned into cost of goods sold as a result ("older" refers to inventory in terms of their accounting and not necessarily in a physical sense). Assuming an inflationary environment, the cost of goods sold is reduced and, as a result, income increases because of LIFO liquidation gains. To capture the true sustainable profitability of a company, we generally exclude the gains generated from LIFO liquidation from our profitability measures.

Adjustment procedures

118. Data requirements:

- The balance of the LIFO reserve account.
- LIFO liquidation gains from the income statement.

119. Calculations:

- Assets: Add the LIFO reserve to inventory.
- Equity: Add the LIFO reserve (after tax) to equity.
- EBITDA, EBIT, and FFO: Deduct LIFO liquidation gains from EBITDA, EBIT, and FFO.

8. Litigation

120. If a company is a defendant in a major lawsuit, we may adjust its debt to account for the potential cost when an adverse outcome (payment of a cash settlement or damages) is probable or has materialized. If the estimated or known amount of the potential payment is material in relation to the company's cash flow or leverage ratios, we add that figure to reported debt. Before doing so, we may reduce the potential payment to reflect the expected reimbursement from legal insurance coverage, cash held in reserve, and extended payment dates; or add accruing interest penalties.

121. The adjusted debt figure therefore includes the present value of the net estimated payout, on an aftertax basis.

122. To achieve the difficult task of sizing the litigation exposure, we may use as a reference any resolved lawsuits that can serve as benchmarks. We also consider the company's reported litigation reserves and the different thresholds for their recognition under IFRS and U.S. GAAP.

123. Because the full financial effects of a lawsuit are difficult to quantify accurately, the analysis also involves techniques such as calculating ranges of outcomes or performing a sensitivity analysis. The results of these techniques can indicate, for example, what effect even higher potential payouts would have on a company's financial profile.

124. If, to allow for a possible adverse financial judgment, a company has placed cash in escrow with the courts or is

expected to do so; or if it had to provide a financial guarantee to the courts, we incorporate the impact of this actual or contingent commitment into the liquidity assessment.

Adjustment procedures

125. Data requirements:

- An estimate or actual amount of the litigation exposure.

126. Calculations:

- Debt: Add the estimated or actual amount of litigation exposure (net of any applicable tax deduction) to reported debt.
- Equity: Subtract the amount of estimated litigation exposure considered to be debt-like that exceeds the accrued litigation exposure, if any.

9. Multi-employer pension plans

127. Some companies in the U.S. participate in multi-employer, defined-benefit pension plans on behalf of their employees. Such companies are predominantly in the transportation, building, construction, manufacturing, hospitality, and grocery sectors. The pension plans are often are referred to as "Taft-Hartley" plans because they fall under the Taft-Hartley Labor Act (officially termed the "The Labor Management Relations Act") of 1947.

128. A multi-employer pension plan is forged by a collective bargaining agreement between companies that generally operate in the same sector and the union(s) that represent the sector's workers. These arrangements share many of the attributes of single-employer plans.

129. We regard the liability associated with a funding deficit on multi-employer pension plans as debt, as we do deficits on single-employer defined-benefit, postretirement obligations. For practical reasons, and because of a lack of pertinent data, we generally do not adjust cash flow measures in our analysis unless significant catch-up contributions are made; nor do we generally adjust our profitability measures.

a) Unique characteristics of multi-employer pension plans

130. Multi-employer pension plans pose some unique challenges, mainly because they are complex, and information about them in companies' financial statements is limited. For example, unlike for single-employer plans, there is generally no information on a company's potential share of a shortfall under a multi-employer plan, unless that company is withdrawing from the plan. Further, because the plans are collective, the sponsoring companies may become liable beyond their otherwise pro rata share of the obligation if another company becomes insolvent.

131. These challenges make it difficult to estimate the amount each company might have to pay to meet current and future obligations under such plans. It is therefore crucial to gather additional information that is timely and relevant, including the specific features of the plan and the collective bargaining process.

132. A company participating in a multi-employer plan faces problems that a company sponsoring a single-company pension plan does not, in particular if it wants to withdraw from such a plan. Companies that withdraw from an underfunded multi-employer plan may incur a withdrawal liability representing their pro rata shares of the total underfunded pension obligation. Determining the withdrawal liability amount accurately is difficult because statutes

provide several different ways to calculate it. Moreover, special rules in certain industries (such as construction, entertainment, and trucking) determine the withdrawal liability trigger points and the size of the obligation. For example, the withdrawal liability may be limited in cases such as a bona fide sale of substantially all of the employer's assets or the company's liquidation or dissolution.

133. A solvent company that exits an underfunded multi-employer pension plan generally continues to make payments for its share of the liabilities for as many years as the Employee Retirement Income Security Act specifies. However, if a company is insolvent, the other participating companies must assume all of its obligations. For single-employer plans, the sponsoring company is liable only for the underfunded portion of its own plan.

134. All of these factors make it difficult to estimate the amount of a company's potential liability under a multi-employer plan to add as debt. To do so, we consider the facts and circumstances associated with the plan. For example, instead of a pro rata share of the collective obligation, we may estimate a lower amount if we view it as plausible that the plan's trustees could reduce the plan's total liability over time by decreasing the level of future employee benefits. We primarily base this determination on information from the company and publicly available data.

b) Accounting and disclosure limitations

135. Under U.S. GAAP and IFRS, a company's withdrawal liability must be both probable and estimable for it to be recognized as a contingent liability in the financial statements. This obligation is therefore seldom accrued or disclosed.

136. Financial statement disclosure on multi-employer plans is typically limited to the significant plans an employer participates in, the company's annual contributions to each plan over the previous three years, and the relative financial health of the plans as indicated by regulatory guidelines.

137. Using publicly available tax and regulatory filings to approximate the funded status of a multi-employer pension is also problematic, considering filing delays. Plans must file Form 5500 (Annual Return/Report of Employee Benefit Plan) with the U.S. Department of Labor. This form provides useful data about a plan's overall financial health, its funding status, number of participants, and contribution levels. However, the form must be filed within 210 days after the end of the plan year (subject to a 75-day extension), and there may be an additional time lag before the Department of Labor publishes the information. The resulting data will therefore be somewhat out of date. In particular, in the period before the publication of the data, fluctuations in discount rates, market returns, and the terms of collective bargaining agreements, participation levels, and other actuarial assumptions may result in changes in the financial health of the plan that the filings do not reflect.

Adjustment procedures

138. Data requirements: Where material, obtain an estimate of the withdrawal liability for each plan a company participates in. If this figure is unavailable, we make an estimate of the company's pro rata share of the funded status based on the following information:

- The funded status of each of the multi-employer plans to which the company contributes. This information may be provided by the company for more recent years, or it may be obtained from the publicly available Form 5500s filed with the Department of Labor. To estimate the funded status, we use the Retirement Protection Act of 1994 liability, minus the fair value of assets as of the same date.

- The company's contributions to each of its multi-employer plans in the corresponding years.
- The total contributions to the multi-employer pension plan by all employers in the corresponding years.
- An applicable haircut for anticipated negotiations.

139. Calculations:

- Debt: Add the estimated withdrawal liability for all plans, net of tax, to debt. Alternatively, if not available, add to debt the estimate of the employer's share of the funded status of each plan (net of any applicable haircut and net of tax).

10. Nonoperating activities and nonrecurring items

140. We define our key income-statement-based metrics (EBITDA, EBIT, and FFO) in a particular fashion. However, the reported financials often do not conform to our views. Therefore it is necessary for us to adjust the reported financial information so that they fit in with our methodology.

a) Operating versus nonoperating items

141. Our decision to include or exclude an activity from a particular metric depends on whether we consider that activity to be operating or nonoperating in nature (see paragraphs 142-158). Independent of that decision, we consider whether an activity is recurring or nonrecurring (see paragraphs 159-164).

142. Our EBIT measure is a traditional view of profit that factors in capital intensity. We consider all income statement activity integral to EBIT, with the exception of interest and taxes. This includes all activity we consider nonoperating that is excluded from EBITDA.

143. Our definition of EBITDA is: Revenue minus operating expenses plus depreciation and amortization (including noncurrent asset impairment and impairment reversals). We include cash dividends received from investments accounted for under the equity method, and exclude the company's share of these investees' profits. This definition generally adheres to what EBITDA stands for: earnings before interest, taxes, depreciation, and amortization. However, it also excludes certain other income statement activity that we view as nonoperating.

144. Our definition of EBITDA aims to capture the results of a company's core operating activities before interest, taxes, and the impact on earnings of capital spending and other investing and financing activities. This definition links to the cash flow statement because we use EBITDA to calculate FFO, which we use as an accrual-based proxy for CFO (cash flow from operations).

145. Generally, this means that any income statement activity whose cash effects have been (or will be) classified as being from operating activities (excluding interest and taxes) are included in our definition of EBITDA.

146. Conversely, income statement activity whose cash effects have been (or will be) classified in the statement of cash flows as being from investing or financing activities is excluded from EBITDA.

147. We may however take alternative views about the classification of transactions to that presented in the statement of cash flows, and this would flow through to our other metrics.

148. Below are examples of how we apply this principle to various scenarios.

149. ***Disposals:-*** Under accounting standards, proceeds from the sale of a subsidiary are classified in the statement of cash flows as an investing cash flow rather than an operating cash flow. Moreover, we view the disposal of a subsidiary as outside core business operations. As such, we do not treat a gain or loss from the sale of a subsidiary as an operating activity and exclude this from our calculation of EBITDA and FFO.

150. The same rationale holds for the sale of property, plant, and equipment. The cash flows arising from such transactions are classified, under accounting standards, as investing activities in the statement of cash flows. Therefore, we would typically view any gains or losses on the sale of property, plant, and equipment as nonoperating items.

151. ***Restructuring costs:-*** We include restructuring costs in our calculation of EBITDA, consistent with their treatment in the cash flow statement as operating activities. Moreover, most companies need to restructure at some point, as the global economy is constantly evolving and businesses alter their operations to remain competitive and viable.

152. ***Acquisition-related costs:-*** These include advisory, legal, and other professional and administrative fees related to an acquisition. We include them in EBITDA, consistent with their treatment in the statement of cash flows as operating activities. Many businesses make acquisitions as part of their growth strategy; therefore it is important to factor these expenses into our metrics.

153. ***Asset impairments/write-downs:-*** Impairments on tangible and intangible noncurrent assets are akin to depreciation or amortization in that they represent a company's income-statement recognition of earlier capital expenditures. We therefore exclude them from our definition of EBITDA. Our definition of EBIT includes impairment charges or reversals. Our decision to exclude an impairment cost or reversal from EBIT would depend on whether we consider it to be recurring or nonrecurring (see paragraphs 159-164).

154. However, impairments on current assets, such as inventory and trade receivables, are included in our calculation of EBITDA. The charges for inventory represent a company's recognition in the income statement of cash that it has already spent, and those for trade receivables represent the reduction of income previously recognized, but which the company will not fully collect.

155. ***Unrealized gains or losses on derivatives:-*** If a company has not achieved the requirements of technical hedge accounting (even though an effective economic hedge may exist), it reports all mark-to-market gains or losses related to the fair-valuing of derivative contracts in the income statement. Although the nature of the underlying activity is often integral to EBITDA, FFO, or both, using mark-to-market accounting can distort these metrics because the derivative contract may be used to hedge several future periods.

156. Therefore, when we have sufficient information, we exclude the unrealized gains or losses not related to current-year activity, so that the income statement represents the economic hedge position achieved in the current financial year (that is, as if hedge accounting had been used). This adjustment is common in the utilities and oil and gas sectors.

157. ***Foreign currency transaction gains and losses:-*** Foreign currency transaction gains or losses arise from transactions denominated in a currency other than a company's functional currency (generally the currency in which it transacts most of its business). Examples include selling goods at prices denominated in a foreign currency, borrowing or lending in a foreign currency, or other contractual obligations denominated in a foreign currency.

158. Currency transaction gains and losses may be viewed as operating or nonoperating in nature. If gains or losses included in operating profit are operating in nature, we do not make adjustments. We may however adjust reported operating results for currency gains and losses that are nonoperating. For example, we may adjust (or exclude) foreign currency gains or losses resulting from the issuance of foreign-currency-denominated debt.

b) Nonrecurring items and pro forma figures

159. The relative stability or volatility of a company's earnings and cash flow is an important measure of credit risk that is embedded in our corporate criteria. For this reason, our use of nonrecurring or pro forma adjustments is limited to the extent that there has been some transformative change in a company's business. Examples of such changes are the divestment of part of the business or a fundamental change in operating strategy.

160. ***Discontinued operations and business divestments:-*** Companies typically segregate their profits or losses from discontinued operations from those of the continuing business; although the segregation of related cash flows is less consistent. We typically exclude profits, losses, and cash flows from discontinued operations from our metrics so that they more accurately reflect the company's ongoing operations.

161. ***Pro forma accounts for intrayear acquisitions or irregular reporting periods:-***If an acquisition has taken place, the financial statements for the year of the acquisition include all the debt of the enlarged group in the year-end balance sheet, but less than the full year's results and cash flows of the enlarged group. This distorts debt-coverage ratios, which therefore do not accurately indicate the company's likely future performance.

162. A similar issue exists when companies have irregular accounting periods, such as after a change in their accounting year-end. In these cases, we may use pro forma financial statements to allow for a more representative measure of full-year performance and more meaningful ratios.

163. ***Asset impairments and write-downs:-*** We generally exclude impairment charges on long-life assets from our measure of EBIT if they are very large and irregular. Excluding a nonrecurring impairment from EBIT produces a better estimate of a company's ongoing profitability, but does not mean we ignore the impairment in our analysis. On the contrary, a significant impairment may indicate that a company's ability to generate future cash flows has diminished.

164. We rarely exclude impairments of operating assets, such as inventories and receivables, from our EBITDA and FFO metrics because we wish to capture this volatility. An exception might be a genuine nonrecurring impairment, such as inventory impairment resulting from damage caused by a fire.

Adjustment procedures

165. Data requirements:

- Amounts of income, expense, and cash flows to be reclassified. The amounts are based on our analytical judgment, using information from the company and our assessments.

166. Calculations:

- Add or subtract amounts from the respective measures--such as, revenue, operating income before and after depreciation and amortization (D&A), D&A, EBIT, EBITDA, CFO, and FFO--and reclassify them according to our view of the underlying activities.
- Because CFO and FFO are aftertax measures, they are also adjusted to reflect tax effects, where feasible.

167. Beyond the standard adjustment, additional insights may be gleaned by adjusting individual line items within cost of goods sold or selling, general, and administrative expense, if there is sufficient data to reflect adjustments at such levels.

11. Leases

168. Companies commonly use leases as a means of financing, and the accounting method for leases distinguishes between operating and finance leases. Finance leases (also known as capital leases) are accounted for in a manner similar to a debt-financed acquisition of an asset and as a balance-sheet liability. Conversely, many operating leases are not accounted for as a balance-sheet liability, but the lease cost is recorded in the profit and loss account in each accounting period.

169. We view this accounting distinction as substantially artificial because under both types of lease arrangements, a company signs a contract that allows it to use an asset, thereby entering into a debt-like obligation to make periodic rental payments.

170. For this reason, we treat operating and finance lease obligations as debt. Reclassifying leases as debt seeks to enhance comparability between companies that finance assets using operating or financing leases and those that do so by incurring debt to finance the purchase of the asset. This adjustment aims to bring companies' financial ratios closer to the underlying economics and to make them more comparable by taking into consideration all of a company's financial obligations, whether on or off the balance sheet.

171. The methodology does not replicate a scenario in which a company finances the acquisition of an asset with debt. Rather, the adjustment is narrower in scope: It attempts to capture only a debt-equivalent for a company's lease contracts. For example, when a company enters into a five-year lease for an asset with a 20-year productive life, the adjustment includes only payments relating to the contracted five-year lease period. We do not use alternative methodologies that fully capitalize the value of the asset, given disclosure and other limitations.

172. However, if we view the term of a lease as artificially short relative to the length of expected use of the leased asset, we may make adjustments to reflect a more economically appropriate depiction of the underlying lease obligation. An example of this approach is for sale-and-leaseback transactions, where if practical we capitalize the entire sale amount.

Adjustment procedures

173. Data requirements:

- Minimum lease payments: The schedule of noncancellable future lease payments over the next five years and beyond (and residual-value guarantees if not included in minimum lease payments).
- Reported annual lease-related operating expenses for the most recent year.
- Deferred gains on sale-and-leaseback transactions that created operating leases.
- We use a fixed discount rate of 7% for all corporate entities we rate. Theoretically, the discount factor could be calculated as the weighted average of the implicit interest rates (that is, the rates charged by the lessors) in each of the company's operating lease arrangements. This is not practicable, however, given accounting disclosure limitations.
- The annual operating-lease-related expense, which we estimate using the average of the first projected annual payment disclosed at the end of the most recent year and the previous year.

174. Calculations (operating leases):

- Debt: We add to debt the present value of future lease payments, calculated using a 7% discount rate. Since minimum lease payments beyond the fifth year are regularly disclosed in aggregate as "thereafter," our methodology assumes that payments beyond the fifth year equal the payment amount in year five, and that the number of years in the "thereafter" period equals the "thereafter" amount divided by the fifth-year amount, rounded to the nearest year. This assumption is capped at a total payment profile of 30 years. IFRS allow companies to disclose amounts payable in years two through five as a single combined amount, instead of separate amounts for each year. In this case, we assume a flat annual payment amount in years two through five, based on the total minimum lease payment disclosed for these four years. We consider future lease payments to be net of sublease rental income only if the lease and sublease terms match and the holder of the sublease is sufficiently creditworthy (that is, has credit quality equivalent to 'BBB-' or higher).

- Income statement and cash flow measures: The lease-related expense is allocated to interest and depreciation expense. EBITDA is increased by adding back the interest and depreciation expense. EBIT is increased by adding back the interest expense. FFO and CFO are increased by adding back the depreciation expense. Gains or losses on sale-and-leaseback transactions are excluded from these measures.
- Interest expense: Interest expense is increased by the product of the 7% discount rate multiplied by the average net present value of the lease payments for the current and previous years.
- Capital expenditures: Our base calculation of capital expenditures, and therefore free operating cash flow (FOCF), excludes any implied capital expenditures relating to operating leases. For lease-intensive sectors, we may use a separate FOCF measure, which includes a capital-expenditure operating lease adjustment, to compare companies' lease and purchase decisions. For this separate FOCF measure, the capital expenditures figure is increased by an implied amount of capital expenditures relating to leases, calculated as the year-over-year change in lease debt, plus annual operating lease depreciation. This amount cannot be negative.
- Property, plant, and equipment: We add the amount of operating leases we reclassify as debt to property, plant, and equipment to approximate the depreciated asset cost.

175. Calculations (finance leases):

- Debt: To the extent that they are not already included in reported debt, we add to debt, finance lease obligations and any obligation associated with failed sale-and-leaseback transactions.
- Capital expenditures: Our base calculation of capital expenditures, and therefore FOCF, excludes any implied capital expenditures relating to finance leases. For lease-intensive sectors, we may use a separate FOCF measure, which includes a capital-expenditure finance lease adjustment, to compare companies' lease and purchase decisions. For this separate FOCF measure, capital expenditures are increased by the value of assets acquired via finance leases during the period.

12. Postretirement employee benefits and deferred compensation

176. We include underfunded defined-benefit obligations for retirees, including pensions and health care coverage (collectively, postretirement benefits or PRB) in our measure of debt. These obligations also include other forms of deferred compensation like retiree lump-sum payment schemes and long-service awards. We include these obligations in our measure of debt because they represent financial obligations that must be paid over time.

177. The adjustments we make relate solely to existing obligations, rather than to potential future obligations.

178. Unlike debt, the measurement of PRB obligations is inherently uncertain: The amount of benefits payable and the value of any assets earmarked to fund those obligations fluctuate over time.

179. To simplify the numerical analysis, we aggregate all retiree benefit plan assets and liabilities for pension, health, and other obligations, netting the positions of a company's plans in surplus against those that are in deficit.

180. We tax-effect our PRB adjustment amounts (that is, give credit for associated tax benefits), unless the related tax benefits have already been, or are unlikely to be, realized. We use the tax rates applicable to the company's plans or, if this is unavailable, the current corporate rate, even though the actual effect of tax charges or benefits in the future may be different. In a typical situation, the company has credible prospects of generating sufficient future taxable income to take advantage of tax deductions related to PRB and so reduce future tax payments.

181. We do not tax-effect the adjustment amounts if we consider a company's ability to generate profits uncertain. Moreover, in such cases, our main focus is the company's liquidity, rather than its capitalization or debt-coverage levels.

a) Capital structure

182. We adjust capitalization for PRB effects by adjusting both debt and equity, where applicable. Debt is increased by the company's tax-effected unfunded PRB obligation. In the instances where equity does not reflect the full extent of the underfunded deficit, equity is adjusted by the difference between the amount accrued on the corporate balance sheet and the amount of net over- or underfunded obligation (net surplus or deficit), net of tax. Debt is not adjusted downward for net surpluses, so net overfunding (surplus) leaves debt unchanged. Equity can be adjusted upward (if the net recognized asset is less than the pretax surplus) or downward. We do not split the debt adjustment between short and long term.

b) Cash flow

183. With PRB and deferred compensation plans, companies are effectively compensating their employees by issuing debt. Our cash flow view is that companies are constructively borrowing from the employees and paying the employees an amount equal to service costs. Additionally, because there is an interest element to the amount borrowed, our cash flow measures assume that imputed interest is paid as incurred. This approach takes a normalized view of cash flows: That is, regardless of when the pension plan is funded over the life of the plan, service costs and net interest costs are paid when incurred.

184. With that in mind, if a company is funding postretirement obligations at a level that is below its net expense (service cost and net interest cost), we interpret this as a form of borrowing that artificially bolsters reported CFO. Conversely, we try to identify catch-up contributions made to reduce unfunded obligations, which would artificially depress reported CFO. We view these contributions as akin to debt amortization, which represents a financing cash flow rather than an operating cash flow.

c) Income statement

185. For the purposes of arriving at income statement measures, we disaggregate the periodic benefit cost into its component parts, allocate those amounts to operating and financing components, and eliminate components we believe are not indicative of the current year's activity. The period's current service cost--reflecting the present value of future benefits employees earned for services rendered during the period--is the sole item we keep as part of operating expenses. We view the interest expense as a finance charge and reclassify it as such if reported differently, such as within operating expenses.

186. Under U.S. GAAP, the expected return on plan assets represents management's subjective, long-range expectation about the performance of the investment portfolio. This concept has been abandoned under IFRS, which under revised

accounting standards, now calculates a net interest figure by multiplying the deficit (or surplus) on the PRB by the discount rate. For the purposes of global comparability, we make adjustments to the reported data of companies still incorporating an expected return element into their interest calculations, such as those reporting under U.S. GAAP, to mimic the IFRS method of calculating net interest. This measure of PRB interest, if a net expense, is added to reported interest. No adjustment is made if net interest is a net income item.

Adjustment procedures

187. Data requirements (for adjustments to income and cash flow items):

- Service cost;
- Interest cost;
- Expected return on pension plan assets, if applicable;
- Actuarial gains or losses (amortization or immediate recognition in earnings);
- Prior service costs (amount included in earnings);
- Other amounts included in earnings (such as special benefits, settlements, and curtailments of benefits);
- Total benefit costs; and
- The sum of employer contributions and direct payments to employees.

188. Data requirements (for adjustments to balance-sheet items):

- PRB-related assets on the balance sheet, including intangible assets, prepaid or noncurrent assets, or any other assets;
- Reported liabilities attributed to PRB, including current and noncurrent liabilities;
- Deferred tax assets related to PRB (or the tax rate applicable to related costs);
- Fair value of plan assets; and
- Total plan liabilities.

Note: Relevant pension and other PRB amounts are combined for all plans.

189. Calculations (income statement and cash flows):

- Operating income: Add to EBIT and EBITDA the total amount of PRB costs charged to operating income, less the current service cost.
- Interest: PRB interest is the net interest cost as reported by companies under IFRS, or as we estimate for companies reporting under U.S. GAAP and other companies using the expected-return approach. If PRB interest is a cost, we include it in adjusted interest expense (we do not reduce interest expense if PRB interest is an income item). This PRB interest is added to reported interest when the net benefit costs are included in operating income. If reported interest already includes an interest component for PRB we adjust it, if necessary, to ensure it reflects the amount of PRB interest.
- Tax expense: We add to, or subtract from, reported tax expenses any tax charge or benefit that results if a company makes additional contributions to postretirement plans or falls short of planned contributions for the current year.
- FFO: FFO equals EBITDA minus net interest expense, minus current tax, with our analytical adjustments applying to each of the three components. EBITDA is adjusted for PRB as described in the first bullet point of this paragraph, while the adjusted net interest expense includes the PRB net interest cost or credit. The current tax expense is adjusted to reflect any tax benefit or charge that the company has received through making excess or insufficient contributions. The net effect of this is that FFO is reduced by the sum of current service costs and net PRB interest, adjusting for tax effects.

- CFO: The adjustment to CFO starts with a calculation of excess contributions or PRB borrowing: Total employer cash contributions (including direct payments to retirees), minus current service costs, minus PRB interest yields the excess contribution if positive, or PRB borrowing if negative. The excess contribution or PRB borrowing is reduced by taxes at the rate applicable to PRB costs (that is, the figure multiplied by 1 minus the tax rate) to create the adjustment amount to CFO. The excess contribution or PRB borrowing is added to, or subtracted from, CFO.

190. Calculations (balance sheet):

- Debt: The net balance sheet asset or liability position (funded status) is calculated as the balance-sheet PRB assets minus PRB liabilities. For the adjustment to debt, if the net pension and postretirement funded status is positive, debt is not adjusted. If the net pension and postretirement funded status is negative, this amount is reduced by the expected tax shield, that is, the amount is multiplied by 1 minus the tax rate. The resulting net amount is added to debt.
- In some jurisdictions, the tax benefit is realized in advance of funding the deficit or paying benefits, for example, when the liability is accrued for tax purposes. The expected tax shield used in our calculation only takes into account amounts that have not yet been received. The adjustment to equity also considers existing balance-sheet amounts.
- Equity: We add to, or subtract from, equity the tax-effected difference (that is, after multiplying that figure by 1 minus the tax rate) between the deficit or surplus on the PRB plan and the reported net plan assets and liabilities.

13. Scope of consolidation

191. When analyzing the creditworthiness of a group, a first critical step is to determine the manner in which a company reports the results of its subsidiaries and affiliates (including their operations, cash flows, assets, and liabilities) in its financial statements. There are several accounting methods to reflect a company's relationship with another company: full consolidation, proportionate consolidation, equity-method consolidation, and deconsolidation (that is, accounted for as an investment).

192. Full consolidation of a subsidiary entails including 100% of each line item of its income, cash flows, assets, and liabilities in the group's financial statements. When a parent owns less than 100% of a subsidiary, the non-controlling-interest holder's share is shown on a separate line in the consolidated income statement and balance sheet.

193. Proportionate consolidation of an affiliate is when all line items of a parent's financial statements include its pro rata share of the affiliate's income, cash flows, assets, and liabilities. This method of consolidation is not common in accounting, but we use it from time to time if we believe that proportionate consolidation best reflects a company's business and financial ties with subsidiaries and affiliates.

194. The equity method of consolidation involves showing the parent's share of profits (or losses) on one line in the income statement, and the parent's investment (initial price paid plus the post-acquisition share of changes in the affiliate's net assets) on the balance sheet. Only cash dividends are reflected in the parent's cash flow statement.

195. Reporting as a nonconsolidated (or deconsolidated) investment means the parent company shows the value of the investment on its balance sheet, typically measured at cost or fair value. The parent does not include any of the income of that affiliate in its results, but reports cash dividends received in the cash flow statement.

196. Although most often the scope of consolidation we employ when analyzing a company is the same as that in the company's financial statements, we may use any consolidation method that in our opinion best reflects a company's business and financial ties with its subsidiaries and affiliates. The analytical adjustments would therefore serve to convert the reported figures to those consistent with our chosen method.

197. No single factor determines our analytical view of a company's relationship with a particular business venture. Rather, the decision will reflect an assessment of factors that, taken together, will lead to a particular characterization. These factors include:

- Strategic importance--integrated lines of business or critical supplier;
- Percentage of ownership (current and prospective);
- Management control;
- Shared name;
- Domicile in the same country;
- Common sources of capital and lending relationships;
- Financial capacity for providing support;
- Significance of the amount of investment;
- Investment relative to the amount of debt at the affiliate or project;
- Position of the other owners (whether strategic or financial investment) and their financial capacity;
- Management's stated stance toward the affiliate or project;
- Whether the creditors of the subsidiary or affiliate have recourse to the parent;
- Shared collective bargaining agreements;
- The bankruptcy-law regimes applicable to the parent and subsidiary;
- Track record of the parent company in similar circumstances; and
- The nature of potential risks.

Adjustment procedures

198. Because a company can use various consolidation methods, there is no standard adjustment procedure. We adjust the reported figures to reflect our quantitative view of the group.

14. Securitization and factoring

199. Securitization can be an important financing vehicle for many companies, potentially enhancing liquidity and enabling them to diversify their funding sources. An important factor is whether the assets and liabilities of a securitization are shown on a company's balance sheet, or deconsolidated and reported as an off-balance-sheet transaction.

200. We may reconsolidate a securitization that a company reports as off-balance-sheet financing. This is because securitizations do not ordinarily transform the risks or the underlying economic reality of the business activity, nor do they necessarily provide equity relief, which allows the company to retain less equity or incur more debt than would otherwise be the case, without affecting its credit quality.

201. If a securitization accomplishes true transfer of risk (contractual, legal, and reputation risk), as is the case with securitization of a tax asset, we regard the transaction as an asset sale and make no adjustments, subject to the considerations in paragraphs 202-206.

202. More commonly, a company retains risks related to the assets transferred under the securitization transaction. We

regard such transactions as being akin to secured financing and bring them back onto the balance sheet if the company has treated them as off-balance-sheet items. The analysis also indicates whether the securitization creates a disadvantage for a company's unsecured creditors that would affect our rating on unsecured debt issues.

203. For example, in our analysis, we treat as on-balance-sheet items, securitization of assets (such as trade receivables) that are regenerated in the ordinary course of business and financed on an ongoing basis. This is because the assets and trading relationships these assets represent are an integral part of a company's operations. Even if a transaction legally transferred risks related to a pool of assets and the company has no obligation to support failing securitizations, this does not mean the company would receive equity relief or that we would not reconsolidate the securitization in our analysis. If a company has a recurring need to finance similar assets, we do not presume it will have permanent access to the securitization market. The company may have to meet future funding needs by other means, and therefore have the requisite equity (and the equivalent level of borrowings) to do so.

204. We treat factoring (or invoice discounting) of trade receivables in a similar way, by including the trade receivable asset and the associated funding liability in the company's balance sheet.

205. Other key considerations for the adjustment of securitizations include:

- The riskiness of the securitized assets. If, as is often the case, a company securitizes its highest-quality or most liquid and therefore low-risk assets, this would limit the extent of any meaningful equity relief, and may create subordination of unsecured creditors, which if significant enough could have an impact on our rating on unsecured debt.
- First-loss exposure. A company may retain liability for a defined portion of loss from a securitization (known as "first-loss exposure"), thereby providing structural credit protection for the securitized asset, which would lower funding costs. The first-loss layer may absorb much of the risk of the securitized asset, and the total gain or loss from the securitization will vary depending on the performance of the assets. Often, only the risk of loss that exceeds the first-loss exposure is transferred to third-party investors.
- Moral recourse. This refers to the likelihood that a company will support a securitization although not legally obliged to do so. Our assessment of moral recourse reflects our view of how a company could behave if losses on the securitization reached catastrophic levels. There is evidence to suggest that companies often tend to bail out troubled securitization transactions (for example, by repurchasing problematic assets or replacing them with other assets) to preserve access to this funding source and, more broadly, to preserve their good name in the capital markets. Moral recourse is magnified when securitizations make up a significant portion of a company's total financing, or when a company remains linked to the securitized assets through the use of a shared corporate name or by continuing in the role of servicer or operator. If we regard the likelihood of moral recourse as significant, we regard the securitized asset and liability as part of the company's balance sheet.

206. The adjustments to a company's financial statements also depend on the extent of risk transfer resulting from a securitization:

- If a company retains most of the risk, our cash flow/leverage ratio calculations include the securitized debt, regardless of whether the securitized debt was reported as on-balance-sheet debt or accounted for as an off-balance-sheet transaction.
- If the company retains none of the risk, the securitized assets are not regenerated in the ordinary course of business, and there are no contingent or indirect liabilities resulting from the transaction, we view the securitization as

equivalent to an asset sale and exclude it from our analysis of the company. This means that if a company has consolidated such a transaction, we use adjustments to remove the securitization assets, debt, earnings, and cash flows from the reported consolidated results in our analysis. We also adjust shareholders' equity, including for the effect of deferred taxes and imputed (or assumed) interest.

207. Several factors limit our ability to make full adjustments for securitizations. When a company reports a securitization as an asset sale in its financial statements, this may create an upfront gain or loss on the sale. When we reconsolidate such a securitization, it is appropriate to reverse such gains because of the uncertainty about whether they will be realized and because they represent nonrecurring income. Likewise, we reverse any loss on the sale that reflects the discount on the sale, to prevent double counting the interest component of the transactions.

208. To calculate the imputed interest, we generally estimate an interest rate because of insufficient information. That rate approximates the interest rate on similar transactions.

209. It is impractical to fully recast the financial statements to consolidate off-balance-sheet securitizations because companies are not required to include pro forma schedules including the securitization transaction in their published accounts.

210. Under U.S. GAAP and IFRS, companies report cash inflows or outflows related to working-capital assets or liabilities, or finance receivables, as operating items on the statement of cash flows. Consequently, securitizations of assets such as receivables affect CFO, and the effect may be particularly significant in reporting periods when the securitizations are initiated or mature.

211. The reporting convention varies with the balance-sheet classification. If a company consolidates a securitization, the related borrowings are treated as a financing activity. If the securitization is off the balance sheet, the effect is akin to accelerated liquidation of the associated assets. There is no separate record of the incurrence of debt, either as an operating liability or a financing source of cash.

212. When our approach is to consolidate a securitization (or, in rare situations, to deconsolidate a securitization), we adjust the cash flow statement to smooth out the variations in CFO that can result from the treatment of a securitization as a sale, which can distort the pattern of recurring cash flow.

Adjustment procedures

213. Data requirements:

- The period-end amount and average outstanding amount of trade receivables sold or securitized that are not on the balance sheet and require adjustments according to our criteria.

214. Calculations:

- Debt and receivables: Add the amount of period-end trade receivables sold or securitized (that is, the uncollected receivables as of the balance-sheet date) to reported debt and receivables.
- Interest expense: Add to interest expense the amount of imputed interest, calculated using the average trade receivables sold over a two-year period (if the data are available) or the trade receivables sold as of the period-end date, at an appropriate benchmark interest rate.
- CFO: Deduct from CFO the proceeds from the securitization if the transaction results in large cash flow movements,

such as on the creation of a securitization or subsequent changes in amounts securitized. Rolling over an existing securitization requires no cash flow adjustment.

15. Seller-provided financing

215. Companies acquiring other companies sometimes finance a portion of the purchase price (or consideration), via seller-provided financing and/or entering into contingent consideration arrangements (that is, "earn outs"). We often view these transactions as a form of financing and therefore we make analytical adjustments to reflect this view. The accounting approach under U.S. GAAP is materially consistent with that under IFRS.

216. The most straightforward form of seller-provided financing is a loan reported at amortized cost plus interest. We include the reported debt amount and interest expense in our respective measures to the extent that they are not already reported as such. No adjustment is necessary on the statement of cash flows, apart from any interest reported under IFRS outside of CFO.

217. The reporting of contingent consideration is more convoluted given the complexity and variability of the instruments. Contingent consideration can take many forms: It can be paid in cash or shares, it can be contingently payable by the acquirer or prepaid and contingently returnable to the acquirer, or it can be contingent upon the recipient's continued employment with the acquirer after the acquisition. The nature and terms of an arrangement dictate the accounting for the arrangement and our analytical treatment.

218. Contingent consideration payable in shares is generally reported within equity and is not remeasured in reporting periods subsequent to the transaction. We do not add to debt an amount for the anticipated settlement of these transactions because we consider them to be prospective equity issuance.

219. Contingent consideration that is prepaid and contingently returnable to the acquiring entity results in an asset on the acquirer's balance sheet that is marked to market in each accounting period until settled. We make no adjustments for these arrangements because they are effectively receivables with no potential future cash outlay. However, we would adjust CFO if the acquirer reported any returned consideration within CFO.

220. Contingent arrangements that require continued employment are technically not part of the consideration paid for the acquisition under U.S. GAAP and IFRS. Rather, such transactions represent remuneration for services after the acquisition. As such, the company does not record the transaction as a liability or expense until the services are performed. We also view such arrangements as payment for services and generally make no analytical adjustments. The recognized expense is a component of our EBITDA and FFO, and its ultimate payment should reduce CFO. Additionally, we do not adjust the reported debt figure unless the original term of the liability was greater than 12 months.

221. Our primary focus is on contingent consideration that is payable in cash, or contracts to be settled in shares that do not qualify as equity. The most common example is a contract to be settled with a variable number of shares. Companies typically record such arrangements, initially, as a liability at fair value and subsequently mark them to market at the end of each accounting period via charges or credits to income until settled. We add to debt the reported value of the liability-classified contingent consideration on each reporting date, understanding that it is not at amortized cost.

222. Consistent with our view of cash flows, described in the next paragraph, we exclude the charges or credits to income from our measurement of EBITDA and FFO, on the basis that this recognition of measurement uncertainty in the income statement is not a core operating cost, but an additional cost of the acquisition. We generally do not attempt to make adjustments to interest expense; such adjustments are usually impractical because interest on the contingent consideration is typically not disclosed.

223. When a company ultimately pays the contingent consideration to the seller, it may report the cash outflow in several ways in the statement of cash flows. We regard these outflows as investing cash flows because they represent cash paid for the purchase of a business. Any cash settlements reported in other ways (for example, as operating or financing cash flows) will be adjusted to reflect this view.

Adjustment procedures

224. Data requirements:

- The carrying value of seller-financed debt or liability-classified contingent consideration on the balance-sheet date.
- Charges or credits included in reported EBITDA.
- Cash paid for or received from the settlement of contingent consideration reported either in cash flows from operating activities or cash flows from financing activities.

225. Calculations:

- Debt: Add to debt, to the extent not already reported as such, the carrying amount of seller-financed debt at amortized cost, as well as any liability-classified contingent consideration reported at fair value.
- EBITDA: If charges or credits from the change in fair value of contingent consideration are included in reported EBITDA, add them back to or subtract them from EBITDA.
- CFO: If cash settlements are reported in CFO, remove the outflow because we consider it an investing activity (acquisition of businesses).

16. Share-based compensation expenses

226. Most major accounting regimes require companies to report the fair value of equity-based grants (such as stock options and restricted share awards) as an expense in the income statement. This amount is generally expensed over the benefiting period, that is, the period over which the company estimates the employee is providing services in exchange for the award.

227. Our cash-flow measures, such as CFO, are not affected by share-based grants payable in shares, given their inherent noncash nature. Additionally, we add back stock-based compensation that is payable in shares to EBITDA and FFO. Our key cash flow/leverage ratios--FFO to debt and debt to EBITDA--therefore exclude stock option expense related to arrangements payable in shares.

228. Certain other share-based arrangements, unlike options or restricted share awards, are payable solely in cash. Examples are stock appreciation rights that are required to be settled in cash, which represent a future call on a company's cash flow. Because they are payable in cash, we do not add back the expense related to these arrangements to EBITDA and FFO. We treat obligations under these arrangements as debt.

Adjustment procedures

229. Data requirements:

- Total share-based compensation expense reported in the period that is payable in shares.
- In jurisdictions that do not require the expensing of such compensation, an estimate of the expense.

230. Calculations:

- EBITDA: If a company has accounted for noncash stock compensation costs as an expense, we add that figure back to EBITDA.
- Operating income, before and after D&A, and EBIT: In jurisdictions that do not require companies to report share-based compensation as expenses, we estimate an expense amount and deduct it from these measures.
- Debt: Add to debt share-based arrangements payable solely in cash.

17. Surplus cash

231. We apply a standard method of calculating surplus cash, which is the amount of cash and liquid investments that is subtracted from gross debt to calculate debt.

232. Standard & Poor's payback ratios are intended to capture the degree to which a company has leveraged its risk assets. Highly liquid financial assets are often low risk. Moreover, we consider that, in addition to cash flow generation, surplus cash is available to repay debt, providing additional flexibility that enhances a company's credit quality. Therefore, it is appropriate to evaluate debt net of surplus cash.

233. Our standard methodology for calculating surplus cash allows the netting of available cash and liquid investments if in our judgment they are highly liquid, and if they are accessible; that is, the cash and liquid investments are truly surplus and therefore could be used to repay debt immediately.

234. We analyze the specifics of a company's cash holdings to evaluate how much of its cash is immediately accessible to reduce debt. To calculate how much cash can be netted off from debt, and unless we get enough information or identify analytical reasons supporting either a lower or higher haircut, we will deduct 25% from the available cash (A), identified as "cash and liquid investments" in "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published on Nov. 19, 2013, to reflect cash that is inaccessible. If we apply the default 25% haircut, adjusted cash (B) available for netting from gross debt would be A x 0.75 = B.

235. We identify cash that might be inaccessible due, among other reasons, to:

- Being held in a nonconvertible currency to the currency of a company's borrowings;
- Distribution restrictions (for example, covenants or cash held in escrow);
- Cash trapped at subsidiaries;
- Tax effects on the repatriation of cash;
- Period-end timing differences unrelated to working capital; or
- Being held in a country whose country risk we assess as high (country risk score of 5) or very high (country risk score of 6), and is in a different currency from the currency of the company's borrowings.

236. If available information indicates greater or lesser accessibility to cash and liquid investments, the haircut would be raised or lowered. For example, the haircut would increase if a company holds a large proportion of cash abroad in a

nonconvertible currency, or if the marginal tax payable on repatriation would exceed 25%. On the other hand, the haircut percentage would be lowered if, for example, detailed analysis showed that the amount of cash and liquid investments accessible on short notice would be higher than our standard assumption, or if any tax payable on repatriation of the cash and liquid investments would be at a rate of less than 25% and we believed that no other factors make the cash and liquid investments inaccessible.

237. If we forecast that a company will generate negative cash flow available for debt repayment, our cash flow/leverage criteria places greater reliance on the current year and the first and second forecast years (see paragraph 117 in "Corporate Methodology," published on Nov. 19, 2013). Forecast negative cash flows could stem from operating activities as well as share buybacks, dividends, or acquisitions, if we forecast these uses of cash based on the company's track record.

238. We will generally not deduct surplus cash from debt if a company is (1) owned by a financial sponsor as defined in Section H.2 of "Corporate Methodology," published on Nov. 19, 2013, or (2) has a business risk profile assessment of "weak" or "vulnerable." However, we deduct surplus cash from debt even if a company meets either of these conditions, as long as:

- We believe that the company has surplus cash identified to retire maturing debt or other debt-like obligations; and
- We believe--typically from the company's track record, market conditions, or financial policy--that management will use the cash to pay off maturing debt or debt-like obligations.

18. Workers' compensation and self-insurance

239. Workers' compensation schemes provide compensation for employees injured in the course of employment. Although schemes differ across jurisdictions, provisions may be made for payments to employees in lieu of wages, compensation for economic losses (past and future), reimbursement for, or payment of, medical and similar expenses, general damages, and benefits payable to the dependents of workers killed during employment.

240. Workers' compensation coverage may be provided through insurance companies, and therefore is not a financial concern for the company. But, in certain instances and/or industries, employers assume direct responsibility for payments such as medical treatment or lost wages.

241. In these cases, under U.S. GAAP or IFRS, the company reports incurred liabilities on the balance sheet as "other liabilities," using an actuarially determined present value of known and estimated claims. Accordingly, these obligations represent a call on future cash flow, distinguishing them from many other less-certain contingencies. They are analogous to postretirement obligations, which we also add to debt.

242. Treating the workers' compensation liability as debt affects many line items on the financial statements. Ideally, if there is sufficient information in the statements, we would make full adjustments, using the same approach as for postretirement employee benefits (see paragraphs 176-190). In practice, the data is not available, so we reclassify these obligations, adjusted for tax, as debt. We may also treat similar self-insurance-type liabilities as debt.

Adjustment procedures

243. Data requirements:

- Net amount reported as a liability for workers' compensation obligations and self-insurance claims.

244. Calculations:

- Debt: Add to debt, the amount recognized for workers' compensation obligations (net of tax) and the net amount recognized for self-insurance claims (net of tax).

F. Index Of Key Ratios

245. Core debt-payback ratios:

- Funds from operations (FFO)/debt
- Debt/EBITDA

246. Supplemental debt-payback and debt-service ratios:

- Cash flow from operations (CFO)/debt
- Free operating cash flow (FOCF)/debt
- Discretionary cash flow (DCF)/debt
- (FFO + interest)/cash interest (FFO cash interest cover)
- EBITDA/interest

247. Profitability ratios:

- EBIT/revenues (EBIT margin)
- EBITDA/revenues (EBITDA margin)
- EBIT/average beginning-of-year and end-of-year capital (return on capital)

VI. GLOSSARY

248. ***Capital:*** Debt plus noncurrent deferred taxes plus equity (plus or minus all applicable adjustments).

249. ***Capital expenditures:*** Funds spent to acquire or develop tangible and certain intangible assets (plus or minus all applicable adjustments).

250. ***Cash interest:*** For the purposes of calculating the FFO cash-interest-cover ratio, "cash interest" includes only cash interest payments on gross financial debt (including bank loans, debt capital market instruments, finance leases, and capitalized interest). Cash interest does not include any Standard & Poor's-adjusted interest on debt-like obligations, such as postretirement benefit obligations or operating leases.

251. ***CFO (cash flow from operations):*** CFO is also referred to as operating cash flow. This measure reflects cash flows from operating activities (as opposed to investing and financing activities), including all interest received and paid, dividends received, and taxes paid in the period (plus or minus all applicable adjustments). For companies that do not use U.S. GAAP, we reclassify as CFO any dividends received, or interest paid or received, that a company reports as investing or financing cash flows.

252. ***Current tax expense:*** This is the amount of income taxes payable on taxable profit, or income tax recoverable from tax losses, in an accounting period (plus or minus all applicable adjustments). Current tax expense is to be distinguished from deferred tax expense.

253. ***DCF (discretionary cash flow):*** FOCF minus cash dividends paid on common stock and preferred stock (plus or minus all applicable adjustments).

254. ***Debt:*** Gross financial debt (including items such as bank loans, debt capital market instruments, and finance leases) minus surplus cash (plus or minus all applicable adjustments).

255. ***Dividends:*** Dividends paid to common and preferred shareholders and to minority interest shareholders of consolidated subsidiaries (plus or minus all applicable adjustments).

256. ***EBIT:*** A traditional view of profit that factors in capital intensity, but also includes interest income, the company's share of equity earnings of associates and joint ventures, and other recurring, nonoperating items (plus or minus all applicable adjustments).

257. ***EBITDA:*** A company's revenue minus operating expenses, plus depreciation and amortization expenses, including impairments on noncurrent assets and impairment reversals (plus or minus all applicable adjustments). Dividends (cash) received from affiliates, associates, and joint ventures accounted for under the equity method are added, while the company's share of profits and losses from these affiliates is excluded.

258. ***Equity:*** Common equity and equity hybrids and minority interests (plus or minus all applicable adjustments).

259. ***FFO (funds from operations):*** EBITDA, minus net interest expense minus current tax expense (plus or minus all applicable adjustments).

260. ***FOCF (free operating cash flow):*** CFO minus capital expenditures (plus or minus all applicable adjustments).

261. ***Interest:*** This is the reported interest expense figure, including noncash interest on conventional debt instruments (such as payment-in-kind, zero-coupon, and inflation-linked debt), minus any interest income derived from assets structurally linked to a debt instrument (plus or minus all applicable adjustments).

262. ***Net interest expense:*** This is the reported interest expense figure, including noncash interest on conventional debt instruments (such as payment-in-kind, zero-coupon, and inflation-linked debt), minus the sum of interest income and dividend income (plus or minus all applicable adjustments).

263. ***Revenues:*** Total sales and other revenues we consider to be operating (plus or minus all applicable adjustments).

VII. APPENDIX

264. This criteria article supersedes:

- "2008 Corporate Criteria: Ratios And Adjustments," published on April 15, 2008;
- "Methodology And Assumptions: Standard & Poor's Revises Key Ratios Used in Global Corporate Ratings Analysis," published on Dec. 28, 2011;
- "Recognizing The Settlement Obligation For Foreign-Currency Hedges Of Debt Principal," published on April 15, 2010;
- "Methodology And Assumptions: Recognizing The Sustainable Cash Cost Of Inflation-Linked Debt For Corporates," published on Feb. 10, 2009;
- "Calculating Adjusted Debt And Interest For Corporate Issuers," published on June 2, 2008;
- "Standard & Poor's Approach To Analyzing Employers' Participation In U.S. Multi-Employer Pension Plans," published on May 30, 2006;
- "Analytical Approach To Postretirement Liabilities of Japanese Companies," published on March 31, 2003; and

- "Camouflaged Share Repurchases: The Rating Implications Of Total-Return Swaps And Similar Equity Derivatives," published on Dec. 7, 2000.

265. This criteria article partly supersedes the section Accounting And Financial Reporting in "2008 Corporate Criteria: Analytical Methodology," published on April 15, 2008.

Frequently Asked Questions

A. Surplus cash

Is the 25% deduction from cash and liquid investments, as described in paragraph 234, the standard amount Standard & Poor's uses to arrive at surplus cash and calculate adjusted debt?

No. The 25% deduction from cash and liquid investments should only be used if we do not have information that would enable the calculation of a more precise amount. If available information indicates greater--or lesser--accessibility to cash and liquid investments than what is assumed by the 25% deduction, we'd lower or raise the amount of the deduction. The deduction should only represent cash at the balance sheet date that is inaccessible to pay interest or repay debt in case of need. Often, we would expect the deduction to be less than 25%.

Can it be appropriate to have a different deduction from cash and liquid investments in arriving at surplus cash each year?

Yes, a different deduction from cash and liquid investments each year is often appropriate. We deduct from cash and liquid investments the amount of cash and liquid investments we believe is, or will be, inaccessible. That amount may not remain constant so a different percentage in each year can better reflect reality.

When developing the deduction from cash and liquid investments to arrive at surplus cash, do you exclude a minimum amount of cash necessary to run the business from the deduction? Could such a minimum amount of cash qualify as "cash trapped at subsidiaries," as noted in paragraph 235?

Generally no. When calculating surplus cash, cash and liquid investments should not be reduced by the amount of expected working capital investment needs. This is because this would disadvantage companies that fund working capital from cash rather than by drawing down on bank lines. In addition, as working capital investment should be "self-extinguishing" or "self-liquidating"--as stock and debt (i.e. inventory and receivables) are converted into cash--it is not appropriate to increase debt for working capital investment needs by reducing cash and liquid investments in the calculation of surplus cash. However, to the extent that we believe that some of the company's working capital investment won't be "self-extinguishing"--due to factors such as stock write-offs, stock discounting, or bad debts--this would be captured in weaker profits in the base-case forecast, which would reduce cash flows and future cash balances. In addition, such working capital investment needs would not qualify as "cash trapped at subsidiaries." An exception to this approach could be where a company has indicated to us an operational cash requirement such that 'cash in the tills' is not practically accessible because it is needed to operate their business (examples include a supermarket who needs cash in tills, or a casino who needs to retain cash in cages). In such cases, we treat this cash need as part of the 'cash trapped at subsidiaries' condition (see paragraph 235).

Do you consider future events (e.g., large expected cash outflows related to capital expenditures, acquisitions, share buybacks and dividends, or lower forecasted earnings) in developing the haircut to gross cash and liquid investments in a particular period?

No. The haircut to gross cash and liquid investments is only for matters of inaccessibility, not future events or needs.

The expected cash outflow or reduced earnings should be included in the base-case forecasts. This will reduce forecast cash flows and period-end cash balances.

Should the haircut applied to liquid investments consider the taxes that would be incurred upon the sale of liquid investments?

Yes. The same principle we apply when tax-effecting cash held overseas should apply here. If the issuer needs to sell liquid investments to generate cash to pay interest or repay debt, the cash that would be received and would be available to pay interest and repay debt would be the net amount of cash after any taxes payable.

Paragraph 235 states that "We identify cash that might be inaccessible due, among other reasons, to…distribution restrictions (for example, covenants or cash held in escrow…)". Are there cases where Standard & Poor's could net off cash that is subject to distribution restrictions from gross debt to calculate debt? If so, do the qualitative preclusions to deducting surplus cash noted in paragraph 238 apply?

Yes, there can be situations where we net off cash that is subject to distribution restrictions from gross debt as part of the surplus cash adjustment--if the cash is restricted for the benefit of creditors with obligations that we include in debt. In these cases, the qualitative restrictions on giving surplus cash credit do not apply, just as they do not apply to netting off other committed assets such as pension assets. For example, if the purpose of the cash distribution restriction is to retain the cash for the benefit of counterparties to debt or debt-like obligations that are otherwise included in our adjusted debt metric, such restricted cash could be netted off gross debt. For example, cash held in escrow for the benefit of debtholders would be fully netted off from debt if the debt is included in Standard & Poor's debt calculation. Additionally, if the exclusion of restricted cash from cash and liquid investments in the calculation of surplus cash would run counter to one of our other analytical adjustments, the restricted cash could be netted off gross debt. An example of this is a cash-collateralized letter of credit facility whereby an issuer overfunds a term loan and places the excess funds in escrow as a back stop for letters of credit or performance guarantees. As long as we believe that the company will not have to make payments under the guarantee, such cash would be eligible for netting against gross debt. This is because, as paragraphs 99 and 100 state, "We do not regard performance guarantees as debt if a company is likely to maintain sufficient work or product quality to avoid making large payments under those guarantees. A company's past record of payments under performance guarantees could indicate the likelihood of future payments under such guarantees. Only if this payment history suggests a high likelihood of future payments would we estimate a potential liability and add that amount to debt."

If an issuer that Standard & Poor's classifies as volatile or highly volatile under the cash flow/leverage criteria has a large amount of surplus cash on hand during a favorable part of the industry cycle, but based on historical evidence you expect it will use most of that cash to meet operating needs during periods of stress, do you take this into account in the surplus cash analysis?

No. When calculating surplus cash, we would only haircut cash and liquid investments by the amount of any of the cash and liquid investments that are inaccessible. Any expected future uses of cash can be captured in the base-case forecast. If an issuer is assessed under the cash flow/leverage criteria to be volatile or highly volatile, then the cash flow/leverage assessment could be modified by one or two categories weaker (as per paragraph 124, section 5, of "Corporate Methodology," published Nov. 19, 2013).

B. Non-operating activities and non-recurring charges

What types of events constitute "transformative events" for the purpose of adjusting for non-recurring items? Is this the same threshold used in the cash/flow leverage criteria, and if so why is there a need to adjust if the weighted average is going to exclude history?

A transformative event is any event that could cause a material change in a company's financial profile. Examples of such changes are the divestment of part of the business or a fundamental change in operating strategy. The idea of a transformative event in these criteria is a similar concept to that contained in paragraph 112 of "Corporate Methodology." When transformative events have occurred and there is sufficient disclosure such that pro forma historical financials are representative of the ongoing entity, historical periods can be used in the cash flow leverage weighted average. Conversely, if the transformative event so alters the business or contorts the historical financials--such that analytical adjustments to historical financials cannot be reasonably employed to in effect pro forma the historical results to be representative of the ongoing entity--then adjustments will not be attempted. Instead, our cash flow leverage analysis will rely on the forecasted periods as described in paragraph 112 of "Corporate Methodology."

Do you adjust for certain accounting anomalies on a regular basis? Do these distortions for "measurement effects" or "accounting distortions," which can lead to misleading figures in the annual financial statements, qualify for adjustment under the non-recurring criteria despite not meeting the "transformative" threshold?

While such distortions are not transformative events per se, we do make adjustments for accounting distortions in certain circumstances for a similar reason: that is to arrive at more meaningful ratios (see paragraphs 140-167). The "nonoperating activities and nonrecurring items" section of the ratio and adjustments criteria gives examples of measurement effects and accounting distortions that we exclude from our financial measures, such as goodwill impairments or unrealized mark-to-market gains or losses on derivatives where a company has not achieved the requirements of technical hedge accounting, even though an effective economic hedge may exist. Other examples of measurement effects and accounting distortions that we exclude from our financial measures include:

- A change in the measurement of a material litigation provision that leads to very significant gains or losses in the year; and
- Fair valuation gains or losses on investment properties under IFRS.

C. Adjusted debt principle

The adjusted debt principle mentions that "to the extent that a company defers payment beyond the term customary for its supply chain, we may add that amount to debt." Under what circumstances would you apply this and how would it be calculated? And how does Standard & Poor's treat reverse factoring arrangements?

If we believe that an issuer's trade payable days are well beyond the range of what would be deemed normal trade terms for the industry, and the improvement to cash flow/leverage measures that results from the stretch in trade payables is deemed to be material, then we'd make an adjustment. In the case of reverse factoring--which we define as financing initiated by a company in order to help its suppliers finance their receivables--we may make a debt adjustment for the customer, if we believe that the trade payable days are well beyond the range of what would be deemed normal trade terms for the industry (see above). However, we would not make an adjustment to debt for the supplier if the supplier has no contractual commitment to meet the customer's obligations and we are confident there is no moral recourse or reputational risk to the supplier as part of the reverse factoring program.

Do structured settlements (e.g., tax settlements and tobacco settlements) qualify as debt under the adjusted debt principle?

Yes. The adjusted debt principle says that we add to debt "incurred liabilities that provide no future offsetting operating benefit." Structured settlements of dispute, whether with commercial or governmental entities, fit this principle and are added to debt (on a discounted basis if feasible).

Under the adjusted debt principle, do you treat a redeemable minority interest as debt?

Yes, but only when the redemption is outside of the control of the issuer (i.e., the minority interest holder has a put option on the subsidiary's shares as opposed to the issuer having a call option to repurchase the shares) and we fully consolidate the subsidiary in our analysis. The liability would be added to our adjusted debt figure based on the adjusted debt principle (see paragraph 21) since the subsidiary is fully consolidated into the parent's accounts and, therefore, the benefits of ownership are accruing to the issuer.

D. Litigation

How does Standard & Poor's capture the risk associated with a large legal settlement, if not quantitatively captured as part of an adjustment to debt?

As stated in paragraphs 191 and 192 of "Corporate Methodology," we consider as part of our Comparable Ratings Analysis factors that may not be already or fully captured elsewhere in our analysis, such as this type of risk. Such factors will generally reflect less frequently observed credit characteristics, may be unique, or may reflect unpredictability or uncertain risk attributes, both positive and negative. In particular, we could assign a negative assessment for Comparable Ratings Analysis, depending on how well (or not) a company identifies, manages, and reserves for contingent risk exposures that can arise if guarantees are called, derivative contract break clauses are activated, or substantial lawsuits are lost.

Related Criteria And Research

- Corporate Methodology, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
- Methodology And Assumptions: Assigning Equity Content To Corporate Entity And North American Insurance Holding Company Hybrid Capital Instruments, April 1, 2013
- Criteria Clarification On Hybrid Capital Step-Ups, Call Options, And Replacement Provisions, Oct. 22, 2012
- Principles Of Credit Ratings, Feb. 16, 2011
- Methodology: Hybrid Capital Issue Features: Update On Dividend Stoppers, Look-Backs, And Pushers, Feb. 10, 2010
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

Exhibit No. BNW-18
Docket UE-140762 *et al.*
Witness: Bruce N. Williams

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

<table>
<tr><td>WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY,

Respondent.</td><td>DOCKETS UE-140762 and UE-140617 (consolidated)</td></tr>
<tr><td>In the Matter of the Petition of

PACIFIC POWER & LIGHT COMPANY,

For an Order Approving Deferral of Costs Related to Colstrip Outage.</td><td>DOCKET UE-131384 (consolidated)</td></tr>
<tr><td>In the Matter of the Petition of

PACIFIC POWER & LIGHT COMPANY,

For an Order Approving Deferral of Costs Related to Declining Hydro Generation.</td><td>DOCKET UE-140094 (consolidated)</td></tr>
</table>

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF BRUCE N. WILLIAMS

Standard & Poor's Credit Assessment

November 2014

Global Credit Portal®

S&P CAPITAL IQ
McGRAW HILL FINANCIAL

This Export copy displays all available data for the selected tab(s), including filtered data that may not currently appear on the screen.

Entity	**PacifiCorp**
Last updated	**27-Aug-2014 05:00 AM PST**
Source	**Adjusted**
Period	**Annual**
Currency	**Reported Currency**
Currency Conversion	**Historical**
Column Order	**Latest on Left**

		Annual	**Annual**
		31-Dec-2013	**31-Dec-2012**
(Units reported in: Millions)	**Most Recent 3 Yrs. Unweighted Avg.**	**USD**	**USD**
Cash & short-term investments, pre-adjusted	60.00	53.00	80.00
Less: Restricted cash (some IFRS reporters)	0.00	0.00	0.00
Less: Surplus cash and near-cash investments	0.00	0.00	0.00
Plus: Cash, consolidating (deconsolidating)			
Cash & short-term investments, adjusted	15.00	13.25	20.00
Receivables, pre-adjusted	674.67	700.00	671.00
Plus: Finance receivables sold			
Plus: Trade receivables sold			
Less: Captive short-term finance receivables	0.00	0.00	0.00
Receivables, adjusted	674.67	700.00	671.00
Inventories, pre-adjusted	451.67	454.00	468.00
Inventory - LIFO reserve			
Inventories, adjusted	451.67	454.00	468.00
Other current assets, pre-adjusted	278.00	235.00	249.00
Total current assets, adjusted	1,419.33	1,402.25	1,408.00
Total assets, pre-adjusted	21,497.67	21,659.00	21,728.00
Less: Surplus cash	-45.00	-39.75	-60.00
Plus: Finance receivables sold			
Less: Total assets of captive finance entity	0.00	0.00	0.00
Plus: Total assets, consolidating (deconsolidating)			
Plus: Trade receivables sold			

Plus: Present value of operating leases	39.35	41.80	32.73
Inventory - LIFO reserve			
Plus: Total assets - Fair Value			
Total assets - Other			
Total assets, adjusted	21,492.01	21,661.05	21,700.73
Debt			
Short-term debt	404.00	238.00	267.00
Long-term debt	6,475.67	6,639.00	6,594.00
Debt, pre-adjusted	6,879.67	6,877.00	6,861.00
Plus: Trade receivables sold			
Plus: OLA debt	39.35	41.80	32.73
Less: Captive finance debt	0.00	0.00	0.00
Plus: Finance receivables sold			
Plus: Debt, consolidating (deconsolidating)			
Less: Surplus cash	-45.00	-39.75	-60.00
Less: Nonrecourse debt	0.00	0.00	0.00
Less: Securitized debt	0.00	0.00	0.00
Plus: Purchase power debt equivalent	229.11	229.11	229.11
Plus: ARO debt adjustment	84.07	89.70	82.55
Plus: Low-equity hybrid reported as equity			
Less: High-equity hybrid reported as debt	0.00	0.00	0.00
Less: Intermediate-equity hybrid rep as debt, Debt	0.00	0.00	0.00
Plus: Intermediate-equity hybrid rep. as equity, Equity	14.00	1.00	20.50
Plus: Pension & other postretirement debt/deferred compensation	283.62	111.15	381.55
Plus: Accrued interest not included in pre-adjusted debt	109.33	110.00	113.00
Debt - Guarantees			
Plus: Debt - Litigation			
Plus: Debt - Workers Compensation/Self Insurance			
Plus: Debt - Volumetric Production Payments			
Plus: Debt - Unamortised capitalized borrowing costs			
Plus: Debt - Derivatives			
Plus: Debt - Foreign currency hedges			
Debt - Contingent considerations			
Plus: Debt - Fair value adjustments			

Plus: Debt - Finance leases			
Plus: Debt - Put options on minority stakes			
Plus: Debt - Debt serviced by third parties			
Debt - Streaming transactions			
Plus: Debt - Shareholder loans			
Plus: Debt - Equity component of convertible debt			
Plus: Debt - Tax Liabilities			
Debt - Issuance cost			
Debt - Seller financing repayable in cash			
Debt - Amortized cost			
Debt - Other			
Debt, adjusted	7,594.14	7,420.01	7,660.44
Preferred stock, pre-adjusted	28.00	2.00	41.00
Less: Low-equity hybrid reported as equity	0.00	0.00	0.00
Plus: High-equity hybrid reported as debt			
Plus: Intermediate-equity hybrid rep as debt, Debt	0.00	0.00	0.00
Less: Intermediate-equity hybrid rep. as equity, Equity	-14.00	-1.00	-20.50
Preferred stock, adjusted	14.00	1.00	20.50
Common equity, pre-adjusted	7,553.00	7,785.00	7,603.00
Less: Captive finance equity	0.00	0.00	0.00
Plus: Equity, consolidating (deconsolidating)			
Plus: Pension & other postretirement equity	0.00	0.00	0.00
Plus: Equity - Government grants			
Plus: Equity - Fair Value adjustments			
Equity - LIFO reserve			
Equity - Other			
Common equity, adjusted	7,553.00	7,785.00	7,603.00

Rep. Currency		**USD**	**USD**
Exchange Rate		**1**	**1**
Conversion Method		**H**	**H**

* Note: NM-Not Meaningful

Exhibit No. BNW-19
Docket UE-140762 *et al.*
Witness: Bruce N. Williams

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF BRUCE N. WILLIAMS

Regulatory Research Associates, "Regulatory Focus, Major Rate Case Decisions – January—June 2014" (July 10, 2014)

November 2014

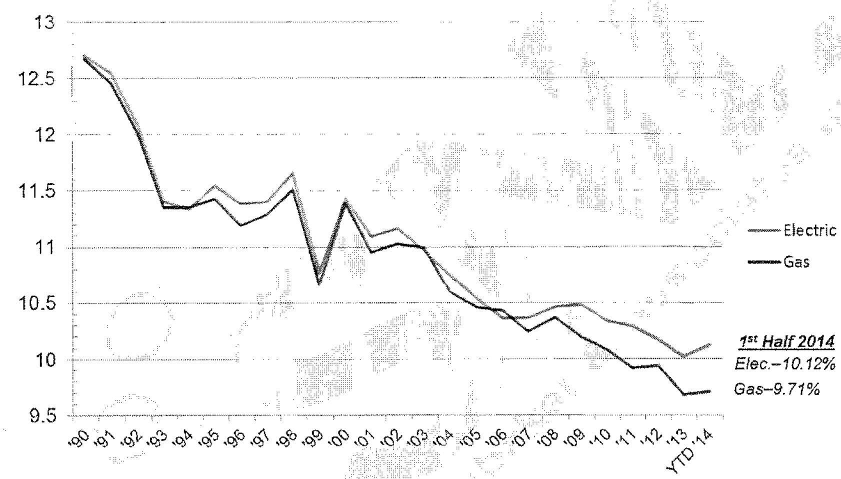
Regulatory Research Associates
REGULATORY FOCUS

July 10, 2014

MAJOR RATE CASE DECISIONS--January-June 2014

The average return on equity (ROE) authorized electric utilities in the first two quarters of 2014 was 10.12% (12 observations), compared to the 10.02% authorized in calendar-2013. We note that the 2014 data includes three surcharge/rider generation cases in Virginia that incorporate plant-specific ROE premiums. Virginia statutes authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects (see the Virginia Commission Profile). Excluding the Virginia surcharge/rider generation cases from the data, the average authorized electric ROE was 9.72% for the first six months of 2014 versus 9.8% in calendar-2013. The average ROE authorized gas utilities for the first two quarters of 2014 was 9.71% (14 observations), compared to 9.68% in calendar-2013. The 2014 averages do not include a Feb. 20, 2014 New York Public Service Commission steam rate decision for Consolidated Edison Co. of New York that adopted a 9.3% ROE. (We note that this report utilizes the simple mean for the return averages.)

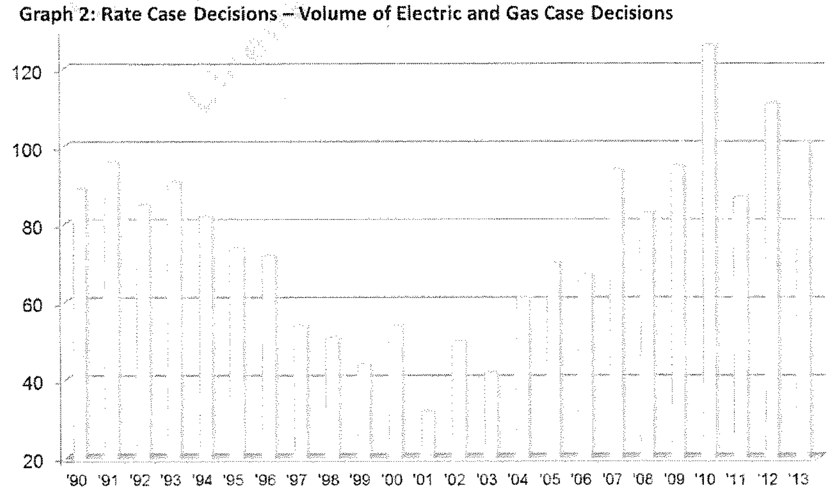
Graph 1: Average Authorized ROEs – Electric and Gas Rate Decisions



Source: SNL Energy/RRA

After reaching a low in the early-2000s, the number of rate case decisions for energy companies has been at an elevated level over the last several years, as shown in Graph 2 below. There were 101 electric and

Graph 2: Rate Case Decisions – Volume of Electric and Gas Case Decisions



Source: SNL Energy/RRA

gas rate cases resolved in 2013 versus 111 in 2012, 87 in 2011, and only 32 back in 2001. Increased costs for environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, and higher employee benefits, argue for the continuation of an active rate case agenda over the next few years.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for delivery operations (delivery only cases are footnoted in our chronology beginning on page 5), thus complicating historical data comparability. We also note that despite the heightened business risk associated with the sluggish economy, average authorized ROEs have declined moderately since 2008. In fact, some state commissions have cited the lethargic economy and customer hardship as factors influencing their equity return authorizations.

The table on page 3 shows the average ROE authorized in major electric and gas rate case decisions annually since 1990, and by quarter since 2009, followed by the number of observations in each period. The tables on page 4 show the composite electric and gas industry data for all major cases summarized annually since 2000 and by quarter for the past six quarters. The individual electric and gas cases decided in the first two quarters of 2014 are listed on pages 5-7, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return (ROR), ROE, and percentage of common equity in the adopted capital structure. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

Please note: Historical data provided in this report may not match data provided on RRA's website due to certain differences in presentation.

Dennis Sperduto

Average Equity Returns Authorized January 1990 - June 2014

		Electric Utilities		Gas Utilities	
Year	**Period**	**ROE %**	**(# Cases)**	**ROE %**	**(# Cases)**
1990	Full Year	12.70	(44)	12.67	(31)
1991	Full Year	12.55	(45)	12.46	(35)
1992	Full Year	12.09	(48)	12.01	(29)
1993	Full Year	11.41	(32)	11.35	(45)
1994	Full Year	11.34	(31)	11.35	(28)
1995	Full Year	11.55	(33)	11.43	(16)
1996	Full Year	11.39	(22)	11.19	(20)
1997	Full Year	11.40	(11)	11.29	(13)
1998	Full Year	11.66	(10)	11.51	(10)
1999	Full Year	10.77	(20)	10.66	(9)
2000	Full Year	11.43	(12)	11.39	(12)
2001	Full Year	11.09	(18)	10.95	(7)
2002	Full Year	11.16	(22)	11.03	(21)
2003	Full Year	10.97	(22)	10.99	(25)
2004	Full Year	10.75	(19)	10.59	(20)
2005	Full Year	10.54	(29)	10.46	(26)
2006	Full Year	10.36	(26)	10.43	(16)
2007	Full Year	10.36	(39)	10.24	(37)
2008	Full Year	10.46	(37)	10.37	(30)
	1st Quarter	10.29	(9)	10.24	(4)
	2nd Quarter	10.55	(10)	10.11	(8)
	3rd Quarter	10.46	(3)	9.88	(2)
	4th Quarter	10.54	(17)	10.27	(15)
2009	**Full Year**	**10.48**	(39)	**10.19**	(29)
	1st Quarter	10.66	(17)	10.24	(9)
	2nd Quarter	10.08	(14)	9.99	(11)
	3rd Quarter	10.26	(11)	9.93	(4)
	4th Quarter	10.30	(17)	10.09	(12)
2010	**Full Year**	**10.34**	(59)	**10.08**	(37)
	1st Quarter	10.32	(13)	10.10	(5)
	2nd Quarter	10.12	(10)	9.88	(5)
	3rd Quarter	10.36	(8)	9.65	(2)
	4th Quarter	10.34	(11)	9.88	(4)
2011	**Full Year**	**10.29**	(42)	**9.92**	(16)
	1st Quarter	10.84	(12)	9.63	(5)
	2nd Quarter	9.92	(13)	9.83	(8)
	3rd Quarter	9.78	(8)	9.75	(1)
	4th Quarter	10.10	(25)	10.07	(21)
2012	**Full Year**	**10.17**	(58)	**9.94**	(35)
	1st Quarter	10.24	(15)	9.57	(3)
	2nd Quarter	9.84	(7)	9.47	(6)
	3rd Quarter	10.06	(7)	9.60	(1)
	4th Quarter	9.90	(21)	9.83	(11)
2013	**Full Year**	**10.02**	(50)	**9.68**	(21)
	1st Quarter	10.23	(8)	9.54	(6)
	2nd Quarter	9.90	(4)	9.84	(8)
2014	**Year-To-Date**	**10.12**	**(12)**	**9.71**	**(14)**

4. RRA

Electric Utilities--Summary Table

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Eq. as % Cap. Struc.	(# Cases)	Amt. $ Mil.	(# Cases)
2000	Full Year	9.20	(12)	11.43	(12)	48.85	(12)	-291.4	(34)
2001	Full Year	8.93	(15)	11.09	(18)	47.20	(13)	14.2	(21)
2002	Full Year	8.72	(20)	11.16	(22)	46.27	(19)	-475.4	(24)
2003	Full Year	8.86	(20)	10.97	(22)	49.41	(19)	313.8	(12)
2004	Full Year	8.44	(18)	10.75	(19)	46.84	(17)	1,091.5	(30)
2005	Full Year	8.30	(26)	10.54	(29)	46.73	(27)	1,373.7	(36)
2006	Full Year	8.24	(24)	10.36	(26)	48.67	(23)	1,465.0	(42)
2007	Full Year	8.22	(38)	10.36	(39)	48.01	(37)	1,401.9	(46)
2008	Full Year	8.25	(35)	10.46	(37)	48.41	(33)	2,899.4	(42)
2009	Full Year	8.23	(38)	10.48	(39)	48.61	(37)	4,192.3	(58)
2010	Full Year	7.99	(59)	10.34	(59)	48.45	(54)	5,567.7	(77)
2011	Full Year	8.00	(43)	10.29	(42)	48.26	(42)	2,853.5	(56)
2012	Full Year	7.95	(51)	10.17	(58)	50.55	(52)	3,131.5	(70)
	1st Quarter	7.81	(13)	10.24	(15)	49.02	(13)	765.9	(17)
	2nd Quarter	7.64	(7)	9.84	(7)	50.56	(6)	653.6	(10)
	3rd Quarter	7.86	(8)	10.06	(7)	50.77	(8)	734.4	(11)
	4th Quarter	7.46	(17)	9.90	(21)	48.20	(16)	1,310.7	(26)
2013	**Full Year**	**7.66**	**(45)**	**10.02**	**(50)**	**49.25**	**(43)**	**3,464.6**	**(64)**
	1st Quarter	7.71	(6)	10.23	(8)	51.08	(8)	251.4	(9)
	2nd Quarter	7.81	(3)	9.90	(4)	49.15	(3)	87.2	(5)
2014	**Year-To-Date**	**7.75**	**(9)**	**10.12**	**(12)**	**50.55**	**(11)**	**338.6**	**(14)**

Gas Utilities--Summary Table

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Eq. as % Cap. Struc.	(# Cases)	Amt. $ Mil.	(# Cases)
2000	Full Year	9.33	(13)	11.39	(12)	48.59	(12)	135.9	(20)
2001	Full Year	8.51	(6)	10.95	(7)	43.96	(5)	114.0	(11)
2002	Full Year	8.80	(20)	11.03	(21)	48.29	(18)	303.6	(26)
2003	Full Year	8.75	(22)	10.99	(25)	49.93	(22)	260.1	(30)
2004	Full Year	8.34	(21)	10.59	(20)	45.90	(20)	303.5	(31)
2005	Full Year	8.25	(29)	10.46	(26)	48.66	(24)	458.4	(34)
2006	Full Year	8.51	(16)	10.43	(16)	47.43	(16)	444.0	(25)
2007	Full Year	8.12	(32)	10.24	(37)	48.37	(30)	813.4	(48)
2008	Full Year	8.48	(30)	10.37	(30)	50.47	(30)	884.8	(41)
2009	Full Year	8.15	(28)	10.19	(29)	48.72	(28)	475.0	(37)
2010	Full Year	7.95	(38)	10.08	(37)	48.56	(38)	816.7	(49)
2011	Full Year	8.09	(18)	9.92	(16)	52.49	(14)	436.3	(31)
2012	Full Year	7.98	(30)	9.94	(35)	51.13	(32)	263.9	(41)
	1st Quarter	7.31	(3)	9.57	(3)	48.80	(3)	39.0	(6)
	2nd Quarter	7.21	(5)	9.47	(6)	51.21	(5)	259.1	(12)
	3rd Quarter	7.53	(1)	9.60	(1)	53.84	(1)	6.1	(3)
	4th Quarter	7.47	(11)	9.83	(11)	50.52	(11)	189.5	(16)
2013	**Full Year**	**7.39**	**(20)**	**9.68**	**(21)**	**50.60**	**(20)**	**493.7**	**(37)**
	1st Quarter	7.67	(6)	9.54	(6)	51.14	(6)	23.5	(9)
	2nd Quarter	7.76	(8)	9.84	(8)	52.12	(8)	62.2	(12)
2014	**Year-To-Date**	**7.72**	**(14)**	**9.71**	**(14)**	**51.70**	**(14)**	**85.7**	**(21)**

ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
2/20/14	Consolidated Edison of New York (NY)	7.05	9.20	48.00	12/14-A	-76.2 (D,B,1)
2/26/14	Northern States Power-Minnesota (ND)	7.45	9.75	52.56	--	9.0 (I,B,2)
2/28/14	MidAmerican Energy (IA)	--	--	--	12/12	263.6 (I,B,Z)
2/28/14	Virginia Electric and Power (VA)	7.95	11.00	50.00	3/15	14.8 (3)
3/14/14	Virginia Electric and Power (VA)	--	12.00	50.00	3/15	3.3 (4)
3/14/14	Virginia Electric and Power (VA)	--	11.00	50.00	3/15	-9.0 (5)
3/17/14	Liberty Utilities (NH)	7.92	9.55	55.00	12/12-YE	9.8 (D,B,I,6)
3/26/14	Potomac Electric Power (DC)	7.65	9.40	49.19	12/12-A	23.4 (D)
3/26/14	Southwestern Public Service (NM)	8.26	9.96	53.89	12/14-A	12.7
2014	***1ST QUARTER: AVERAGES/TOTAL***	**7.71**	**10.23**	**51.08**		**251.4**
	OBSERVATIONS	**6**	**8**	**8**		**9**
4/2/14	Delmarva Power & Light (DE)	7.26	9.70	49.22	12/12-A	15.1 (I)
4/23/14	Duquesne Light (PA)	--	--	--	4/15	48.0 (D,B)
5/16/14	Entergy Texas (TX)	--	9.80	--	3/13	18.5 (I,B,7)
5/30/14	Fitchburg Gas & Electric Light (MA)	8.28	9.70	47.78	12/12-YE	5.6 (D)
6/6/14	Wisconsin Power and Light (WI)	7.90 (8)	10.40	50.46	12/15-A	0.0 (8)
2014	***2ND QUARTER: AVERAGES/TOTAL***	**7.81**	**9.90**	**49.15**		**87.2**
	OBSERVATIONS	**3**	**4**	**3**		**5**
2014	***YEAR-TO-DATE: AVERAGES/TOTAL***	**7.75**	**10.12**	**50.55**		**338.6**
	OBSERVATIONS	**9**	**12**	**11**		**14**

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/21/14	Avista Corp. (OR)	7.47	9.65	48.00	--	5.6 (B,Z)
1/22/14	Connecticut Natural Gas (CT)	7.88	9.18	52.52	12/12-A	7.3 (R)
1/28/14	Atmos Energy (KS)	--	--	--	9/13-YE	1.2 (9)
1/29/14	Baltimore Gas and Electric (MD)	--	--	--	12/18-A	34.1 (Z,10)
1/31/14	Columbia Gas of Maryland (MD)	--	--	--	--	-- (11)
2/20/14	Consolidated Edison of New York (NY)	7.10	9.30	48.00	12/14-A	-54.6 (B,12)
2/21/14	Questar Gas (UT)	7.64	9.85	52.07	12/14-A	7.6 (B)
2/28/14	Bay State Gas (MA)	7.83	9.55	53.68	12/12-YE	19.3
3/16/14	Atmos Energy (CO)	8.07	9.72	52.57	12/12-A	1.3 (I,B)
3/19/14	Missouri Gas Energy (MO)	--	--	--	9/13-YE	1.7 (13)
2014	***1ST QUARTER: AVERAGES/TOTAL***	**7.67**	**9.54**	**51.14**		**23.5**
	OBSERVATIONS	**6**	**6**	**6**		**9**
4/2/14	Laclede Gas (MO)	--	--	--	12/13-YE	7.0 (13)
4/21/14	Northern Utilities (NH)	8.28	9.50	51.76	12/12-YE	4.6 (I,B,14)
4/22/14	Atmos Energy (KY)	7.71	9.80	49.16	11/14-A	8.6 (I)
4/23/14	Missouri Gas Energy (MO)	--	--	--	4/13	7.8 (B)
5/8/14	CenterPoint Energy Resources (MN)	7.42	9.59	52.60	9/14-A	32.9 (I)
5/8/14	National Fuel Gas Distribution (NY)	7.56	9.10	48.00	9/14-A	-3.6 (B,15)
5/15/14	Delta Natural Gas (KY)	--	--	--	12/13-YE	1.1 (16)
6/4/14	Washington Gas Light (MD)	--	--	--	9/14-A	1.7 (10)
6/6/14	Wisconsin Power and Light (WI)	7.90 (17)	10.40	50.46	12/15-A	-5.0 (17)
6/12/14	Southwest Gas (So. California) (CA)	6.83	10.10	55.00	12/14-A	1.9
6/12/14	Southwest Gas (No. California) (CA)	8.18	10.10	55.00	12/14-A	2.5
6/12/14	Southwest Gas (So. Lake Tahoe) (CA)	8.18	10.10	55.00	12/14-A	2.7
2014	***2ND QUARTER: AVERAGES/TOTAL***	**7.76**	**9.84**	**52.12**		**62.2**
	OBSERVATIONS	**8**	**8**	**8**		**12**
2014	***YEAR-TO-DATE: AVERAGES/TOTAL***	**7.72**	**9.71**	**51.70**		**85.7**
	OBSERVATIONS	**14**	**14**	**14**		**21**

FOOTNOTES

A- Average
B- Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
COC- Case involved only the determination of cost-of-capital parameters.
CWIP- Construction work in progress
D- Applies to electric delivery only
DCt Date certain rate base valuation
E- Estimated
Hy- Hypothetical capital structure utilized
I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
M- "Make-whole" rate change based on return on equity or overall return authorized in previous case.
R- Revised
Te- Temporary rates implemented prior to the issuance of final order.
U- Double leverage capital structure utilized.
W- Case withdrawn
YE- Year-end
Z- Rate change implemented in multiple steps.
* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Approved joint proposal (stipulation) includes two-year rate plan that specifies a second-year $124 million revenue requirement increase.
(2) Approved settlement includes a four-year electric rate plan. In addition to the $9 million first-year rate increase, an incremental $9.3 million second-step increase based on a 10% ROE is to be implemented in 2014, and an incremental $10.1 million third-step increase based on a 10% ROE is to be implemented in 2015. Rates are to remain unchanged in 2016 based on a 10.25% ROE.
(3) Increase authorized through a surcharge, Rider W, which reflects in rates the investment in the Warren County Power Station and associated transmission facilities.
(4) This proceeding determines the revenue requirement for Rider B, which is the mechanism through which the company recovers costs associated with its plan to convert the Altavista, Hopewell, and Southampton Power Stations to burn biomass fuels.
(5) This proceeding determines the revenue requirement for Rider S for the year ending 3/31/2015. Rider S recognizes the company's investment in the Virginia City Hybrid Energy Center.
(6) An additional step increase of about $1.1 million was authorized to be effective 4/1/14.
(7) The rate increase is effective retroactive to 3/31/14.
(8) Return on capital. The Commission approved the company's proposal to freeze electric base rates in 2015 and 2016.
(9) Case represents the company's gas system reliability surcharge rider.
(10) Case involves the strategic infrastructure replacement (STRIDE) rider, a surcharge associated with the company's infrastrucure replacement program.
(11) Company's proposed strategic infrastructure replacement (STRIDE) program and an associated rider were rejected by the Commission.
(12) Approved joint proposal (stipulation) includes a three-year rate plan that specifies second-year $38.6 million and third-year $56.8 million revenue requirement increases.
(13) Case involves the company's infrastrucure system replacement surcharge rider.
(14) Additional "step increases" of about $1.4 million to be effective on 5/1/14 and 5/1/15.
(15) Two-year rate plan adopted. A $6.1 million revenue requirement increase is to be effective on 10/1/14.
(16) Case involves the company's pipe replacement program (PRP) rider.
(17) Return on capital. The Commission approved the company's proposal to reduce gas base rates by $5 million in 2015 and then freeze base rates in 2016.

Dennis Sperduto

Exhibit No. BNW-20
Docket UE-140762 *et al.*
Witness: Bruce N. Williams

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF BRUCE N. WILLIAMS

Standard & Poor's Ratings Direct Report, "Corporate Methodology" (November 19, 2013)

November 2014

STANDARD & POOR'S RATINGS SERVICES
McGRAW HILL FINANCIAL

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Criteria | Corporates | General:

Corporate Methodology

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Corporate Methodology

*(**Editor's Note:** We originally published this criteria article on November 19, 2013. We're republishing this article following our periodic review completed on October 17, 2014. We republished this article to add a section on frequently asked questions. The definitions of financial sponsor-owned companies and financial sponsors in this article have been superseded by those in "The Treatment Of Non-Common Equity Financing In Nonfinancial Corporate Entities," published April 29, 2014. We republished this article on Dec. 16, 2013, to make some adjustments to language. These adjustments have no impact on our ratings or the effective date of the criteria.)*

1. Standard & Poor's Ratings Services is updating its criteria for rating corporate industrial companies and utilities. The criteria organize the analytical process according to a common framework and articulate the steps in developing the stand-alone credit profile (SACP) and issuer credit rating (ICR) for a corporate entity.

2. This article is related to our criteria article "Principles Of Credit Ratings," which we published on Feb. 16, 2011.

SUMMARY OF THE CRITERIA

3. The criteria describe the methodology we use to determine the SACP and ICR for corporate industrial companies and utilities. Our assessment reflects these companies' business risk profiles, their financial risk profiles, and other factors that may modify the SACP outcome (see "General Criteria: Stand-Alone Credit Profiles: One Component Of A Rating," published Oct. 1, 2010, for the definition of SACP). The criteria provide clarity on how we determine an issuer's SACP and ICR and are more specific in detailing the various factors of the analysis. The criteria also provide clear guidance on how we use these factors as part of determining an issuer's ICR. Standard & Poor's intends for these criteria to provide the market with a framework that clarifies our approach to fundamental analysis of corporate credit risks.

4. The business risk profile comprises the risk and return potential for a company in the markets in which it participates, the competitive climate within those markets (its industry risk), the country risks within those markets, and the competitive advantages and disadvantages the company has within those markets (its competitive position). The business risk profile affects the amount of financial risk that a company can bear at a given SACP level and constitutes the foundation for a company's expected economic success. We combine our assessments of industry risk, country risk, and competitive position to determine the assessment for a corporation's business risk profile.

5. The financial risk profile is the outcome of decisions that management makes in the context of its business risk profile and its financial risk tolerances. This includes decisions about the manner in which management seeks funding for the company and how it constructs its balance sheet. It also reflects the relationship of the cash flows the organization can achieve, given its business risk profile, to the company's financial obligations. The criteria use cash flow/leverage analysis to determine a corporate issuer's financial risk profile assessment.

6. We then combine an issuer's business risk profile assessment and its financial risk profile assessment to determine its anchor (see table 3). Additional rating factors can modify the anchor. These are: diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance. Comparable ratings analysis is the last

analytical factor under the criteria to determine the final SACP on a company.

7. These criteria are complemented by industry-specific criteria called Key Credit Factors (KCFs). The KCFs describe the industry risk assessments associated with each sector and may identify sector-specific criteria that supersede certain sections of these criteria. As an example, the liquidity criteria state that the relevant KCF article may specify different standards than those stated within the liquidity criteria to evaluate companies that are part of exceptionally stable or volatile industries. The KCFs may also define sector-specific criteria for one or more of the factors in the analysis. For example, the analysis of a regulated utility's competitive position is different from the methodology to evaluate the competitive position of an industrial company. The regulated utility KCF will describe the criteria we use to evaluate those companies' competitive positions (see "Key Credit Factors For The Regulated Utility Industry," published Nov. 19, 2013).

SCOPE OF THE CRITERIA

8. This methodology applies to nonfinancial corporate issuer credit ratings globally. Please see "Criteria Guidelines For Recovery Ratings On Global Industrial Issuers' Speculative-Grade Debt," published Aug. 10, 2009, and "2008 Corporate Criteria: Rating Each Issue," published April 15, 2008, for further information on our methodology for determining issue ratings. This methodology does not apply to the following sectors, based on the unique characteristics of these sectors, which require either a different framework of analysis or substantial modifications to one or more factors of analysis: project finance entities, project developers, transportation equipment leasing, auto rentals, commodities trading, investment holding companies and companies that maximize their returns by buying and selling equity holdings over time, Japanese general trading companies, corporate securitizations, nonprofit and cooperative organizations, master limited partnerships, general partnerships of master limited partnerships, and other entities whose cash flows are primarily derived from partially owned equity holdings.

IMPACT ON OUTSTANDING RATINGS

9. We expect about 5% of corporate industrial companies and utilities ratings within the scope of the criteria to change. Of that number, we expect approximately 90% to receive a one-notch change, with the majority of the remainder receiving a two-notch change. We expect the ratio of upgrades to downgrades to be around 3:1.

EFFECTIVE DATE AND TRANSITION

10. These criteria are effective immediately on the date of publication. We intend to complete our review of all affected ratings within the next six months.

METHODOLOGY

A. Corporate Ratings Framework

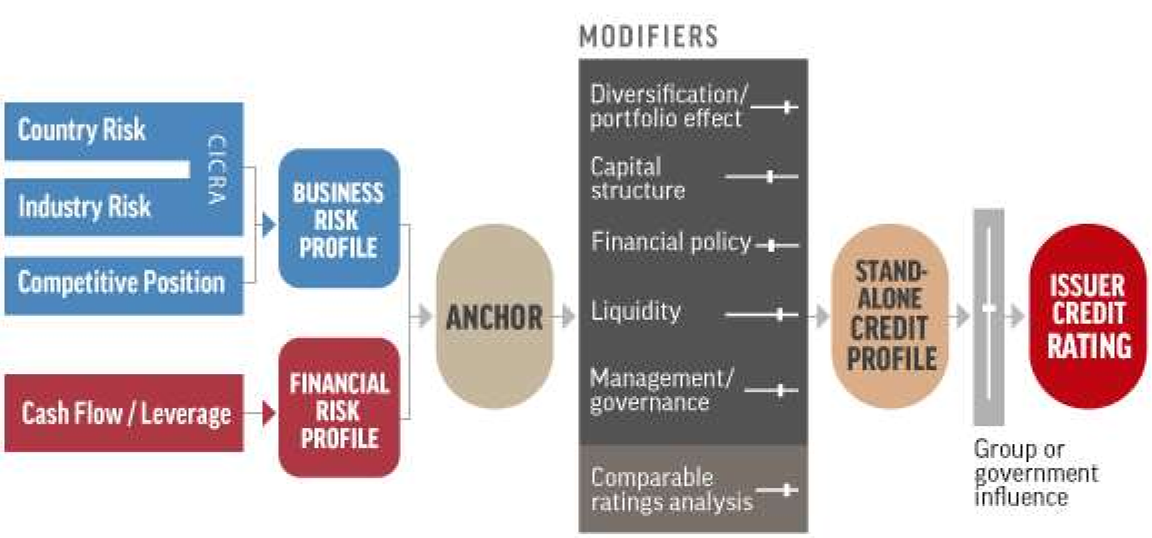
11. The corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several factors so that Standard & Poor's considers all salient issues. First we analyze the company's business risk profile, then evaluate its financial risk profile, then combine those to determine an issuer's anchor. We then analyze six factors that could potentially modify our anchor conclusion.

12. To determine the assessment for a corporate issuer's business risk profile, the criteria combine our assessments of industry risk, country risk, and competitive position. Cash flow/leverage analysis determines a company's financial risk profile assessment. The analysis then combines the corporate issuer's business risk profile assessment and its financial risk profile assessment to determine its anchor. In general, the analysis weighs the business risk profile more heavily for investment-grade anchors, while the financial risk profile carries more weight for speculative-grade anchors.

13. After we determine the anchor, we use additional factors to modify the anchor. These factors are: diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance. The assessment of each factor can raise or lower the anchor by one or more notches--or have no effect. These conclusions take the form of assessments and descriptors for each factor that determine the number of notches to apply to the anchor.

14. The last analytical factor the criteria call for is comparable ratings analysis, which may raise or lower the anchor by one notch based on a holistic view of the company's credit characteristics.

Corporate Criteria Framework



15. The three analytic factors within the business risk profile generally are a blend of qualitative assessments and quantitative information. Qualitative assessments distinguish risk factors, such as a company's competitive advantages, that we use to assess its competitive position. Quantitative information includes, for example, historical cyclicality of revenues and profits that we review when assessing industry risk. It can also include the volatility and level of profitability we consider in order to assess a company's competitive position. The assessments for business risk profile are: 1, excellent; 2, strong; 3, satisfactory; 4, fair; 5, weak; and 6, vulnerable.

16. In assessing cash flow/leverage to determine the financial risk profile, the analysis focuses on quantitative measures. The assessments for financial risk profile are: 1, minimal; 2, modest; 3, intermediate; 4, significant; 5, aggressive; and 6, highly leveraged.

17. The ICR results from the combination of the SACP and the support framework, which determines the extent of the difference between the SACP and the ICR, if any, for group or government influence. Extraordinary influence is then captured in the ICR. Please see "Group Rating Methodology," published Nov. 19, 2013, and "Rating Government-Related Entities: Methodology And Assumptions," published Dec. 9, 2010, for our methodology on group and government influence.

18. Ongoing support or negative influence from a government (for government-related entities), or from a group, is factored into the SACP (see "SACP criteria"). While such ongoing support/negative influence does not affect the industry or country risk assessment, it can affect any other factor in business or financial risk. For example, such support or negative influence can affect: national industry analysis, other elements of competitive position, financial risk profile, the liquidity assessment, and comparable ratings analysis.

19. The application of these criteria will result in an SACP that could then be constrained by the relevant sovereign rating and transfer and convertibility (T&C) assessment affecting the entity when determining the ICR. In order for the final ICR to be higher than the applicable sovereign rating or T&C assessment, the entity will have to meet the conditions established in "Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions," published Nov. 19, 2013.

1. Determining the business risk profile assessment

20. Under the criteria, the combined assessments for country risk, industry risk, and competitive position determine a company's business risk profile assessment. A company's strengths or weaknesses in the marketplace are vital to its credit assessment. These strengths and weaknesses determine an issuer's capacity to generate cash flows in order to service its obligations in a timely fashion.

21. Industry risk, an integral part of the credit analysis, addresses the relative health and stability of the markets in which a company operates. The range of industry risk assessments is: 1, very low risk; 2, low risk; 3, intermediate risk; 4, moderately high risk; 5, high risk; and 6, very high risk. The treatment of industry risk is in section B.

22. Country risk addresses the economic risk, institutional and governance effectiveness risk, financial system risk, and payment culture or rule of law risk in the countries in which a company operates. The range of country risk assessments is: 1, very low risk; 2, low risk; 3, intermediate risk; 4, moderately high risk; 5, high risk; and 6, very high risk. The treatment of country risk is in section C.

23. The evaluation of an enterprise's competitive position identifies entities that are best positioned to take advantage of key industry drivers or to mitigate associated risks more effectively--and achieve a competitive advantage and a stronger business risk profile than that of entities that lack a strong value proposition or are more vulnerable to industry risks. The range of competitive position assessments is: 1, excellent; 2, strong; 3, satisfactory; 4, fair; 5, weak; and 6, vulnerable. The full treatment of competitive position is in section D.

24. The combined assessment for country risk and industry risk is known as the issuer's Corporate Industry and Country Risk Assessment (CICRA). Table 1 shows how to determine the combined assessment for country risk and industry risk.

Table 1

Determining The CICRA

	--Country risk assessment--					
Industry risk assessment	**1 (very low risk)**	**2 (low risk)**	**3 (intermediate risk)**	**4 (moderately high risk)**	**5 (high risk)**	**6 (very high risk)**
1 (very low risk)	1	1	1	2	4	5
2 (low risk)	2	2	2	3	4	5
3 (intermediate risk)	3	3	3	3	4	6
4 (moderately high risk)	4	4	4	4	5	6
5 (high risk)	5	5	5	5	5	6
6 (very high risk)	6	6	6	6	6	6

25. The CICRA is combined with a company's competitive position assessment in order to create the issuer's business risk profile assessment. Table 2 shows how we combine these assessments.

Table 2

Determining The Business Risk Profile Assessment

	--CICRA--					
Competitive position assessment	**1**	**2**	**3**	**4**	**5**	**6**
1 (excellent)	1	1	1	2	3*	5
2 (strong)	1	2	2	3	4	5
3 (satisfactory)	2	3	3	3	4	6
4 (fair)	3	4	4	4	5	6
5 (weak)	4	5	5	5	5	6
6 (vulnerable)	5	6	6	6	6	6

*See paragraph 26.

26. A small number of companies with a CICRA of 5 may be assigned a business risk profile assessment of 2 if all of the following conditions are met:

- The company's competitive position assessment is 1.
- The company's country risk assessment is no riskier than 3.
- The company produces significantly better-than-average industry profitability, as measured by the level and volatility of profits.
- The company's competitive position within its sector transcends its industry risks due to unique competitive

advantages with its customers, strong operating efficiencies not enjoyed by the large majority of the industry, or scale/scope/diversity advantages that are well beyond the large majority of the industry.

27. For issuers with multiple business lines, the business risk profile assessment is based on our assessment of each of the factors--country risk, industry risk, and competitive position--as follows:

- Country risk: We use the weighted average of the country risk assessments for the company across all countries where companies generate more than 5% of sales or EBITDA, or where more than 5% of fixed assets are located.
- Industry risk: We use the weighted average of the industry risk assessments for all business lines representing more than 20% of the company's forecasted earnings, revenues or fixed assets, or other appropriate financial measures if earnings, revenue, or fixed assets do not accurately reflect the exposure to an industry.
- Competitive position: We assess all business lines identified above for the components competitive advantage, scope/scale/diversity, and operating efficiency (see section D). They are then blended using a weighted average of revenues, earnings, or assets to form the preliminary competitive position assessment. The level of profitability and volatility of profitability are then assessed based on the consolidated financials for the enterprise. The preliminary competitive position assessment is then blended with the profitability assessment, as per section D.5, to assess competitive position for the enterprise.

2. Determining the financial risk profile assessment

28. Under the criteria, cash flow/leverage analysis is the foundation for assessing a company's financial risk profile. The range of assessments for a company's cash flow/leverage is 1, minimal; 2, modest; 3, intermediate; 4, significant; 5, aggressive; and 6, highly leveraged. The full treatment of cash flow/leverage analysis is the subject of section E.

3. Merger of financial risk profile and business risk profile assessments

29. An issuer's business risk profile assessment and its financial risk profile assessment are combined to determine its anchor (see table 3). If we view an issuer's capital structure as unsustainable or if its obligations are currently vulnerable to nonpayment, and if the obligor is dependent upon favorable business, financial, and economic conditions to meet its commitments on its obligations, then we will determine the issuer's SACP using "Criteria For Assigning 'CCC+', 'CCC', 'CCC-', And 'CC' Ratings," published Oct. 1, 2012. If the issuer meets the conditions for assigning 'CCC+', 'CCC', 'CCC-', and 'CC' ratings, we will not apply Table 3.

Table 3

Combining The Business And Financial Risk Profiles To Determine The Anchor

	--Financial risk profile--					
Business risk profile	**1 (minimal)**	**2 (modest)**	**3 (intermediate)**	**4 (significant)**	**5 (aggressive)**	**6 (highly leveraged)**
1 (excellent)	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
2 (strong)	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
3 (satisfactory)	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
4 (fair)	bbb/bbb-	bbb-	bb+	bb	bb-	b
5 (weak)	bb+	bb+	bb	bb-	b+	b/b-
6 (vulnerable)	bb-	bb-	bb-/b+	b+	b	b-

30. When two anchor outcomes are listed for a given combination of business risk profile assessment and financial risk profile assessment, an issuer's anchor is determined as follows:

- When a company's financial risk profile is 4 or stronger (meaning, 1-4), its anchor is based on the comparative strength of its business risk profile. We consider our assessment of the business risk profile for corporate issuers to be points along a possible range. Consequently, each of these assessments that ultimately generate the business risk profile for a specific issuer can be at the upper or lower end of such a range. Issuers with stronger business risk profiles for the range of anchor outcomes will be assigned the higher anchor. Those with a weaker business risk profile for the range of anchor outcomes will be assigned the lower anchor.
- When a company's financial risk profile is 5 or 6, its anchor is based on the comparative strength of its financial risk profile. Issuers with stronger cash flow/leverage ratios for the range of anchor outcomes will be assigned the higher anchor. Issuers with weaker cash flow/leverage ratios for the range of anchor outcomes will be assigned the lower anchor. For example, a company with a business risk profile of (1) excellent and a financial risk profile of (6) highly leveraged would generally be assigned an anchor of 'bb+' if its ratio of debt to EBITDA was 8x or greater and there were no offsetting factors to such a high level of leverage.

4. Building on the anchor

31. The analysis of diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance may raise or lower a company's anchor. The assessment of each modifier can raise or lower the anchor by one or more notches--or have no effect in some cases (see tables 4 and 5). We express these conclusions using specific assessments and descriptors that determine the number of notches to apply to the anchor. However, this notching in aggregate can't lower an issuer's anchor below 'b-' (see "Criteria For Assigning 'CCC+', 'CCC', 'CCC-', And 'CC' Ratings," published Oct. 1, 2012, for the methodology we use to assign 'CCC' and 'CC' category SACPs and ICRs to issuers).

32. The analysis of the modifier diversification/portfolio effect identifies the benefits of diversification across business lines. The diversification/portfolio effect assessments are 1, significant diversification; 2, moderate diversification; and 3, neutral. The impact of this factor on an issuer's anchor is based on the company's business risk profile assessment and is described in Table 4. Multiple earnings streams (which are evaluated within a firm's business risk profile) that are less-than-perfectly correlated reduce the risk of default of an issuer (see Appendix D). We determine the impact of this factor based on the business risk profile assessment because the benefits of diversification are significantly reduced with poor business prospects. The full treatment of diversification/portfolio effect analysis is the subject of section F.

Table 4

Modifier Step 1: Impact Of Diversification/Portfolio Effect On The Anchor

	--Business risk profile assessment--					
Diversification/portfolio effect	**1 (excellent)**	**2 (strong)**	**3 (satisfactory)**	**4 (fair)**	**5 (weak)**	**6 (vulnerable)**
1 (significant diversification)	+2 notches	+2 notches	+2 notches	+1 notch	+1 notch	0 notches
2 (moderate diversification)	+1 notch	+1 notch	+1 notch	+1 notch	0 notches	0 notches
3 (neutral)	0 notches	0 notches	0 notches	0 notches	0 notches	0 notches

33. After we adjust for the diversification/portfolio effect, we determine the impact of the other modifiers: capital structure, financial policy, liquidity, and management and governance. We apply these four modifiers in the order listed in Table 5. As we go down the list, a modifier may (or may not) change the anchor to a new range (one of the ranges in the four right-hand columns in the table). We'll choose the appropriate value from the new range, or column, to determine the next modifier's effect on the anchor. And so on, until we get to the last modifier on the

list—management and governance. For example, let's assume that the anchor, after adjustment for diversification/portfolio effect but before adjusting for the other modifiers, is 'a'. If the capital structure assessment is very negative, the indicated anchor drops two notches, to 'bbb+'. So, to determine the impact of the next modifier-—financial policy-—we go to the column 'bbb+ to bbb-' and find the appropriate assessment—in this theoretical example, positive. Applying that assessment moves the anchor up one notch, to the 'a- and higher' category. In our example, liquidity is strong, so the impact is zero notches and the anchor remains unchanged. Management and governance is satisfactory, and thus the anchor remains 'a-' (see chart following table 5).

Table 5

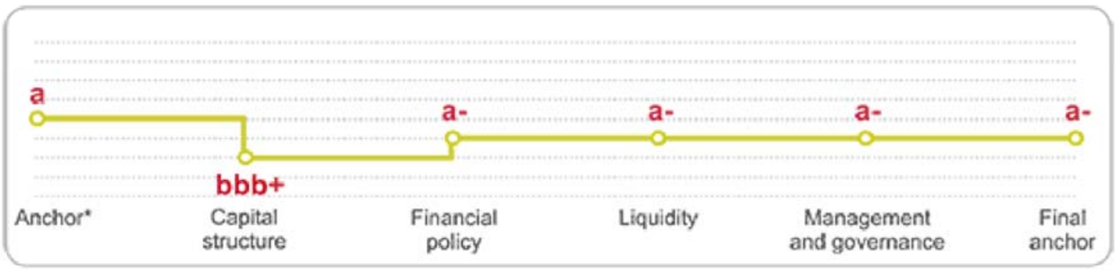
Modifier Step 2: Impact Of Remaining Modifier Factors On The Anchor

	--Anchor range--			
	'a-' and higher	**'bbb+' to 'bbb-'**	**'bb+' to 'bb-'**	**'b+' and lower**
Factor/Assessment				
Capital structure (see section G)				
1 (Very positive)	2 notches	2 notches	2 notches	2 notches
2 (Positive)	1 notch	1 notch	1 notch	1 notch
3 (Neutral)	0 notches	0 notches	0 notches	0 notches
4 (Negative)	-1 notch	-1 notch	-1 notch	-1 notch
5 (Very negative)	-2 or more notches	-2 or more notches	-2 or more notches	-2 notches
Financial policy (FP; see section H)				
1 (Positive)	+1 notch if M&G is at least satisfactory	+1 notch if M&G is at least satisfactory	+1 notch if liquidity is at least adequate and M&G is at least satisfactory	+1 notch if liquidity is at least adequate and M&G is at least satisfactory
2 (Neutral)	0 notches	0 notches	0 notches	0 notches
3 (Negative)	-1 to -3 notches(1)	-1 to -3 notches(1)	-1 to -2 notches(1)	-1 notch
4 (FS-4, FS-5, FS-6, FS-6 [minus])	N/A(2)	N/A(2)	N/A(2)	N/A(2)
Liquidity (see section I)				
1 (Exceptional)	0 notches	0 notches	0 notches	+1 notch if FP is positive, neutral, FS-4, or FS-5 (3)
2 (Strong)	0 notches	0 notches	0 notches	+1 notch if FP is positive, neutral, FS-4, or FS-5 (3)
3 (Adequate)	0 notches	0 notches	0 notches	0 notches
4 (Less than adequate [4])	N/A	N/A	-1 notch(5)	0 notches
5 (Weak)	N/A	N/A	N/A	'b-' cap on SACP
Management and governance (M&G; see section J)				
1 (Strong)	0 notches	0 notches	0, +1 notches(6)	0, +1 notches(6)
2 (Satisfactory)	0 notches	0 notches	0 notches	0 notches
3 (Fair)	-1 notch	0 notches	0 notches	0 notches
4 (Weak)	-2 or more notches(7)	-2 or more notches(7)	-1 or more notches(7)	-1 or more notches(7)

Table 5

Modifier Step 2: Impact Of Remaining Modifier Factors On The Anchor (cont.)
(1) Number of notches depends on potential incremental leverage. (2) See "Financial Policy," section H.2. (3) Additional notch applies only if we expect liquidity to remain exceptional or strong. (4) See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013. SACP is capped at 'bb+.' (5) If issuer SACP is 'bb+' due to cap, there is no further notching. (6) This adjustment is one notch if we have not already captured benefits of strong management and governance in the analysis of the issuer's competitive position. (7) Number of notches depends upon the degree of negative effect to the enterprise's risk profile.

Example: How Remaining Modifiers Can Change The Anchor



*After adjusting for diversification/portfolio effect. See paragraph 33.

34. Our analysis of a firm's capital structure assesses risks in the firm's capital structure that may not arise in the review of its cash flow/leverage. These risks include the currency risk of debt, debt maturity profile, interest rate risk of debt, and an investments subfactor. We assess a corporate issuer's capital structure on a scale of 1, very positive; 2, positive; 3, neutral; 4, negative; and 5, very negative. The full treatment of capital structure is the subject of section G.

35. Financial policy serves to refine the view of a company's risks beyond the conclusions arising from the standard assumptions in the cash flow/leverage, capital structure, and liquidity analyses. Those assumptions do not always reflect or adequately capture the long-term risks of a firm's financial policy. The financial policy assessment is, therefore, a measure of the degree to which owner/managerial decision-making can affect the predictability of a company's financial risk profile. We assess financial policy as 1) positive, 2) neutral, 3) negative, or as being owned by a financial sponsor. We further identify financial sponsor-owned companies as "FS-4", "FS-5", "FS-6", or "FS-6 (minus)." The full treatment of financial policy analysis is the subject of section H.

36. Our assessment of liquidity focuses on the monetary flows--the sources and uses of cash--that are the key indicators of a company's liquidity cushion. The analysis also assesses the potential for a company to breach covenant tests tied to declines in earnings before interest, taxes, depreciation, and amortization (EBITDA). The methodology incorporates a qualitative analysis that addresses such factors as the ability to absorb high-impact, low-probability events, the nature of bank relationships, the level of standing in credit markets, and the degree of prudence of the company's financial risk management. The liquidity assessments are 1, exceptional; 2, strong; 3, adequate; 4, less than adequate; and 5, weak. An SACP is capped at 'bb+' for issuers whose liquidity is less than adequate and 'b-' for issuers whose liquidity is weak, regardless of the assessment of any modifiers or comparable ratings analysis. (For the complete methodology on assessing corporate issuers' liquidity, see "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013.)

37. The analysis of management and governance addresses how management's strategic competence, organizational

effectiveness, risk management, and governance practices shape the company's competitiveness in the marketplace, the strength of its financial risk management, and the robustness of its governance. The range of management and governance assessments is: 1, strong; 2, satisfactory; 3, fair; and 4, weak. Typically, investment-grade anchor outcomes reflect strong or satisfactory management and governance, so there is no incremental benefit. Alternatively, a fair or weak assessment of management and governance can lead to a lower anchor. Also, a strong assessment for management and governance for a weaker entity is viewed as a favorable factor, under the criteria, and can have a positive impact on the final SACP outcome. For the full treatment of management and governance, see "Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers," published Nov. 13, 2012.

5. Comparable ratings analysis

38. The anchor, after adjusting for the modifiers, could change one notch up or down in order to arrive at an issuer's SACP based on our comparable ratings analysis, which is a holistic review of a company's stand-alone credit risk profile, in which we evaluate an issuer's credit characteristics in aggregate. A positive assessment leads to a one-notch improvement, a negative assessment leads to a one-notch reduction, and a neutral assessment indicates no change to the anchor. The application of comparable ratings analysis reflects the need to 'fine-tune' ratings outcomes, even after the use of each of the other modifiers. A positive or negative assessment is therefore likely to be common rather than exceptional.

B. Industry Risk

39. The analysis of industry risk addresses the major factors that Standard & Poor's believes affect the risks that entities face in their respective industries. (See "Methodology: Industry Risk," published Nov. 19, 2013.)

C. Country Risk

40. The analysis of country risk addresses the major factors that Standard & Poor's believes affect the country where entities operate. Country risks, which include economic, institutional and governance effectiveness, financial system, and payment culture/rule of law risks, influence overall credit risks for every rated corporate entity. (See "Country Risk Assessment Methodology And Assumptions," published Nov. 19, 2013.)

1. Assessing country risk for corporate issuers

41. The following paragraphs explain how the criteria determine the country risk assessment for a corporate entity. Once it's determined, we combine the country risk assessment with the issuer's industry risk assessment to calculate the issuer's CICRA (see section A, table 1). The CICRA is one of the factors of the issuer's business risk profile. If an issuer has very low to intermediate exposure to country risk, as represented by a country risk assessment of 1, 2, or 3, country risk is neutral to an issuer's CICRA. But if an issuer has moderately high to very high exposure to country risk, as represented by a country risk assessment of 4, 5, or 6, the issuer's CICRA could be influenced by its country risk assessment.

42. Corporate entities operating within a single country will receive a country risk assessment for that jurisdiction. For entities with exposure to more than one country, the criteria prospectively measure the proportion of exposure to each

country based on forecasted EBITDA, revenues, or fixed assets, or other appropriate financial measures if EBITDA, revenue, or fixed assets do not accurately reflect the exposure to that jurisdiction.

43. Arriving at a company's blended country risk assessment involves multiplying its weighted-average exposures for each country by each country's risk assessment and then adding those numbers. For the weighted-average calculation, the criteria consider countries where the company generates more than 5% of its sales or where more than 5% of its fixed assets are located, and all weightings are rounded to the nearest 5% before averaging. We round the assessment to the nearest integer, so a weighted assessment of 2.2 rounds to 2, and a weighted assessment of 2.6 rounds to 3 (see table 6).

Table 6

Hypothetical Example Of Weighted-Average Country Risk For A Corporate Entity

Country	Weighting (% of business*)	Country risk§	Weighted country risk
Country A	45	1	0.45
Country B	20	2	0.4
Country C	15	1	0.15
Country D	10	4	0.4
Country E	10	2	0.2
Weighted-average country risk assessment (rounded to the nearest whole number)	--	--	2

*Using EBITDA, revenues, fixed assets, or other financial measures as appropriate. §On a scale from 1-6, lowest to highest risk.

44. A weak link approach, which helps us calculate a blended country risk assessment for companies with exposure to more than one country, works as follows: If fixed assets are based in a higher-risk country but products are exported to a lower-risk country, the company's exposure would be to the higher-risk country. Similarly, if fixed assets are based in a lower-risk country but export revenues are generated from a higher-risk country and cannot be easily redirected elsewhere, we measure exposure to the higher-risk country. If a company's supplier is located in a higher-risk country, and its supply needs cannot be easily redirected elsewhere, we measure exposure to the higher-risk country. Conversely, if the supply chain can be re-sourced easily to another country, we would not measure exposure to the higher risk country.

45. Country risk can be mitigated for a company located in a single jurisdiction in the following narrow case. For a company that exports the majority of its products overseas and has no direct exposure to a country's banking system that would affect its funding, debt servicing, liquidity, or ability to transfer payments from or to its key counterparties, we could reduce the country risk assessment by one category (e.g., 5 to 4) to determine the adjusted country risk assessment. This would only apply for countries where we considered the financial system risk subfactor a constraint on the overall country risk assessment for that country. For such a company, other country risks are not mitigated: Economic risk still applies, albeit less of a risk than for a company that sells domestically (potential currency volatility remains a risk for exporters); institutional and governance effectiveness risk still applies (political risk may place assets at risk); and payment culture/rule of law risk still applies (legal risks may place assets and cross-border contracts at risk).

46. Companies will often disclose aggregated information for blocks of countries, rather than disclosing individual country

information. If the information we need to estimate exposure for all countries is not available, we use regional risk assessments. Regional risk assessments are calculated as averages of the unadjusted country risk assessments, weighted by gross domestic product of each country in a defined region. The criteria assess regional risk on a 1-6 scale (strongest to weakest). Please see Appendix A, Table 26, which lists the constituent countries of the regions.

47. If an issuer does not disclose its country-level exposure or regional-level exposure, individual country risk exposures or regional exposures will be estimated.

2. Adjusting the country risk assessment for diversity

48. We will adjust the country risk assessment for a company that operates in multiple jurisdictions and demonstrates a high degree of diversity of country risk exposures. As a result of this diversification, the company could have less exposure to country risk than the rounded weighted average of its exposures might indicate. Accordingly, the country risk assessment for a corporate entity could be adjusted if an issuer meets the conditions outlined in paragraph 49.

49. The preliminary country risk assessment is raised by one category to reflect diversity if all of the following four conditions are met:

- If the company's head office, as defined in paragraph 51, is located in a country with a risk assessment stronger than the preliminary country risk assessment;
- If no country, with a country risk assessment equal to or weaker than the company's preliminary country risk assessment, represents or is expected to represent more than 20% of revenues, EBITDA, fixed assets, or other appropriate financial measures;
- If the company is primarily funded at the holding level, or through a finance subsidiary in a similar or stronger country risk environment than the holding company, or if any local funding could be very rapidly substituted at the holding level; and
- If the company's industry risk assessment is '4' or stronger.

50. The country risk assessment for companies that have 75% or more exposure to one jurisdiction cannot be improved and will, in most instances, equal the country risk assessment of that jurisdiction. But the country risk assessment for companies that have 75% or more exposure to one jurisdiction can be weakened if the balance of exposure is to higher risk jurisdictions.

51. We consider the location of a corporate head office relevant to overall risk exposure because it influences the perception of a company and its reputation--and can affect the company's access to capital. We determine the location of the head office on the basis of 'de facto' head office operations rather than just considering the jurisdiction of incorporation or stock market listing for public companies. De facto head office operations refers to the country where executive management and centralized high-level corporate activities occur, including strategic planning and capital raising. If such activities occur in different countries, we take the weakest country risk assessment applicable for the countries in which those activities take place.

D. Competitive Position

52. Competitive position encompasses company-specific factors that can add to, or partly offset, industry risk and country risk--the two other major factors of a company's business risk profile.

53. Competitive position takes into account a company's: 1) competitive advantage, 2) scale, scope, and diversity, 3) operating efficiency, and 4) profitability. A company's strengths and weaknesses on the first three components shape its competitiveness in the marketplace and the sustainability or vulnerability of its revenues and profit. Profitability can either confirm our initial assessment of competitive position or modify it, positively or negatively. A stronger-than-industry-average set of competitive position characteristics will strengthen a company's business risk profile. Conversely, a weaker-than-industry-average set of competitive position characteristics will weaken a company's business risk profile.

54. These criteria describe how we develop a competitive position assessment. They provide guidance on how we assess each component based on a number of subfactors. The criteria define the weighting rules applied to derive a preliminary competitive position assessment. And they outline how this preliminary assessment can be maintained, raised, or lowered based on a company's profitability. Standard & Poor's competitive position analysis is both qualitative and quantitative.

1. The components of competitive position

55. A company's competitive position assessment can be: 1, excellent; 2, strong; 3, satisfactory; 4, fair; 5, weak; or 6, vulnerable.

56. The analysis of competitive position includes a review of:

- Competitive advantage;
- Scale, scope, and diversity;
- Operating efficiency; and
- Profitability.

57. We follow four steps to arrive at the competitive position assessment. First, we separately assess competitive advantage; scale, scope, and diversity; and operating efficiency (excluding any benefits or risks already captured in the issuer's CICRA assessment). Second, we apply weighting factors to these three components to derive a weighted-average assessment that translates into a preliminary competitive position assessment. Third, we assess profitability. Finally, we combine the preliminary competitive position assessment and the profitability assessment to determine the final competitive position assessment. Profitability can confirm, or influence positively or negatively, the competitive position assessment.

58. We assess the relative strength of each of the first three components by reviewing a variety of subfactors (see table 7). When quantitative metrics are relevant and available, we use them to evaluate these subfactors. However, our overall assessment of each component is qualitative. Our evaluation is forward-looking; we use historical data only to the extent that they provide insight into future trends.

59. We evaluate profitability by assessing two subcomponents: level of profitability (measured by historical and projected nominal levels of return on capital, EBITDA margin, and/or sector-specific metrics) and volatility of profitability (measured by historically observed and expected fluctuations in EBITDA, return on capital, EBITDA margin, or sector specific metrics). We assess both subcomponents in the context of the company's industry.

Table 7

Competitive Position Components And Subfactors

Component	Explanation	Subfactors
1. Competitive advantage (see Appendix B, section 1)	The strategic positioning and attractiveness to customers of a company's products or services, and the fragility or sustainability of its business model	• Strategy • Differentiation/uniqueness/product positioning/bundling • Brand reputation and marketing • Product and/or service quality • Barriers to entry and customers' switching costs • Technological advantage and capabilities and vulnerability to/ability to drive technological displacement • Asset base characteristics
2. Scale, scope, and diversity (see Appendix B, section 2)	The concentration or diversification of business activities	• Diversity of products or services • Geographic diversity • Volumes, size of markets and revenues, and market share • Maturity of products or services
3. Operating efficiency (see Appendix B, section 3)	The quality and flexibility of a company's asset base and its cost management and structure	• Cost structure • Manufacturing processes • Working capital management • Technology
4. Profitability		• Level of profitability (historical and projected return on capital, EBITDA margin, and/or sector-relevant measure) • Volatility of profitability

2. Assessing competitive advantage, scale, scope, and diversity, and operating efficiency

60. We assess competitive advantage; scale, scope, and diversity; and operating efficiency as: 1, strong; 2, strong/adequate; 3, adequate; 4, adequate/weak; or 5, weak. Tables 8, 9, and 10 provide guidance for assessing each component.

61. In assessing the components' relative strength, we place significant emphasis on comparative analysis. Peer comparisons provide context for evaluating the subfactors and the resulting component assessment. We review company-specific characteristics in the context of the company's industry, not just its narrower subsector. (See list of industries and subsectors in Appendix B, table 27.) For example, when evaluating an airline, we will benchmark the assessment against peers in the broader transportation-cyclical industry (including the marine and trucking subsectors), and not just against other airlines. Likewise, we will compare a home furnishing manufacturer with other companies in the consumer durables industry, including makers of appliances or leisure products. We might occasionally extend the comparison to other industries if, for instance, a company's business lines cross several industries, or if there are a limited number of rated peers in an industry, subsector, or region.

62. An assessment of strong means that the company's strengths on that component outweigh its weaknesses, and that the combination of relevant subfactors results in lower-than-average business risk in the industry. An assessment of adequate means that the company's strengths and weaknesses with respect to that component are balanced and that the relevant subfactors add up to average business risk in the industry. A weak assessment means that the company's weaknesses on that component override any strengths and that its subfactors, in total, reveal higher-than-average business risk in the industry.

63. Where a component is not clearly strong or adequate, we may assess it as strong/adequate. A component that is not clearly adequate or weak may end up as adequate/weak.

64. Although we review each subfactor, we don't assess each individually--and we seek to understand how they may reinforce or weaken each other. A component's assessment combines the relative strengths and importance of its subfactors. For any company, one or more subfactors can be unusually important--even factors that aren't common in the industry. Industry KCF articles identify subfactors that are consistently more important, or happen not to be relevant, in a given industry.

65. Not all subfactors may be equally important, and a single one's strength or weakness may outweigh all the others. For example, if notwithstanding a track record of successful product launches and its strong brand equity, a company's strategy doesn't appear adaptable, in our view, to changing competitive dynamics in the industry, we will likely not assess its competitive advantage as strong. Similarly, if its revenues came disproportionately from a narrow product line, we might view this as compounding its risk of exposure to a small geographic market and, thus, assess its scale, scope, and diversity component as weak.

66. From time to time companies will, as a result of shifting industry dynamics or strategies, expand or shrink their product or service lineups, alter their cost structures, encounter new competition, or have to adapt to new regulatory environments. In such instances, we will reevaluate all relevant subfactors (and component assessments).

Table 8

Competitive Advantage Assessment

Qualifier	What it means	Guidance
Strong	• The company has a major competitive advantage due to one or a combination of factors that supports revenue and profit growth, combined with lower-than-average volatility of profits. • There are strong prospects that the company can sustain this advantage over the long term. • This should enable the company to withstand economic downturns and competitive and technological threats better than its competitors can. • Any weaknesses in one or more subfactors are more than offset by strengths in other subfactors that produce sustainable and profitable revenue growth.	• The company's business strategy is highly consistent with, and adaptable to, industry trends and conditions and supports its leadership in the marketplace. • It consistently develops and markets well-differentiated products or services, aligns products with market demand, and enhances the attractiveness or uniqueness of its value proposition through bundling. • Its superior track record of product development, service quality, and customer satisfaction and retention support its ability to maintain or improve its market share. • Its products or services command a clear price premium relative to its competitors' thanks to its brand equity, technological leadership, or quality of service; it is able to sustain this advantage with innovation and effective marketing. • It benefits from barriers to entry from regulation, market characteristics, or intrinsic benefits (such as patents, technology, or customer relationships) that effectively reduce the threat of new competition. • It has demonstrated a commitment and ability to effectively reinvest in its asset base, as evidenced by a continuous pipeline of new products and/or improvement in key capabilities, such as employee retention, customer care, distribution, and supplier relations. These tangible and intangible assets support long term prospects of sustainable and profitable growth.
Adequate	• The company has some competitive advantages, but not so large as to create a superior business model or durable benefit compared to its peers'. • It has some but not all drivers of competitiveness. Certain factors support the business' long-term viability and should result in average profitability and average profit volatility during recessions or periods of increased competition. However, these drivers are partially offset by the company's disadvantages or lack of sustainability of other factors.	• The company's strategy is well adapted to marketplace conditions, but it is not necessarily a leader in setting industry trends. • It exhibits neither superior nor subpar abilities with respect to product or service differentiation and positioning. • Its products command no price premium or advantage relative to competing brands as a result of its brand equity or its technological positioning. • It may enjoy some barriers to entry that provide some defense against competitors but don't overpower them. It faces some risk of product/service displacement or substitution longer term. • Its metrics of product or service quality and customer satisfaction or retention are in line with its industry's average. The company could lose customers to competitors if it makes operational missteps. • Its asset profile does not exhibit particularly superior or inferior characteristics compared to other industry participants. These assets generate consistent revenue and profit growth although long-term prospects are subject to some uncertainty.

Weak	• The company has few, if any, competitive advantages and a number of competitive disadvantages. • Because the company lacks many competitive advantages, its long-term prospects are uncertain, and its profit volatility is likely to be higher than average for its industry. • The company is less likely than its competitors to withstand economic, competitive, or technological threats. • Alternatively, the company has weaknesses in one or more subfactors that could keep its profitability below average and its profit volatility above average during economic downturns or periods of increased competition.	• The company's strategy is inconsistent with, or not well adapted to, marketplace trends and conditions. • There is evidence of little innovation, slowness in developing and marketing new products, an inability to raise prices, and/or ineffective bundling. • Its products generally enjoy no price premium relative to competing brands and it often has to sell its products at a lower price than its peers can command. • It has suffered or is at risk of suffering customer defections due to falling quality and because customers perceive its products or services to be less valuable than those of its competitors. • Its revenues and market shares are vulnerable to aggressive pricing by existing or new competitors or to technological displacement risks over the near to medium term. • Its metrics of product or service quality and customer satisfaction or retention are weaker than the industry average. • Its reinvestment in its business is lower than its peers', its ability to retain operational talent is limited, its distribution network is inefficient, and its revenue could stagnate or decline as result.

Table 9

Scale, Scope, And Diversity

Qualifier	What it means	Guidance
Strong	• The company's overall scale, scope, and diversity supports stable revenues and profits by rendering it essentially invulnerable to all but the most disruptive combinations of adverse factors, events, or trends. • Its significant advantages in scale, scope, and diversity enable it to withstand economic, regional, competitive, and technological threats better than its competitors can.	• The company's range of products or services is among the most comprehensive in its sector. It derives its revenue and profits from a broader set of products or services than the industry average. • Its products and services enjoy industry-leading market shares relative to other participants in its industry. • It does not rely on a particular customer or small group of customers. If it does, the customer(s) is/are of high credit quality, their demand is highly sustainable, or the company and its customer(s) have significant interdependence. • It does not depend on any particular supplier or related group of suppliers that it could not easily replace. If it does, the supplier(s) is/are of high credit quality, or the company and its supplier(s) have significant interdependence. • It enjoys broader geographic diversity than its peers and doesn't overly depend on a single regional or local market. If it does, the market is local, often for regulatory reasons. The company's production or service centers are diversified across several locations. • It holds a strategic investment that provides positive business diversification.
Adequate	• The company's overall scale, scope, and diversity is comparable to its peers'. • Its ability to withstand economic, competitive, or technological threats is comparable to the ability of others within its sector.	• The company has a broad range of products or services compared with its competitors and doesn't depend on a particular product or service for the majority of its revenues and profits. • Its market share is average compared with that of its competitors. • Its dependence on or concentration of key customers is no higher than the industry average, and the loss of a top customer would be unlikely to pose a high risk to its business stability. • It isn't overly dependent on any supplier or regional group of suppliers that it couldn't easily replace. • It doesn't depend excessively on a single local or regional market, and its geographic footprint of production and revenue compares with that of other industry participants.

Weak	• The company's lack of scale, scope, and diversity compromises the stability and sustainability of its revenues and profits. • The company's vulnerability to, or reliance on, various elements of scale, scope, and diversity leaves it less likely than its competitors to withstand economic, competitive, or technological threats.	• The company's product or service lineup is somewhat limited compared to those of its sector peers. The company derives its profits from a narrow group of products or services, and has not achieved significant market share compared with its peers. • Demand for its products or services is lower than for its competitors', and this trend isn't improving. • It relies heavily on a particular customer or small group of customers, and the characteristics of the customer base do not mitigate this risk. • It depends on a particular supplier or group of suppliers, which it would not be able to easily replace without incurring high switching costs. • It depends disproportionately on a single local or regional economy for selling its goods or services, and the company's industry is global. • Key production assets are concentrated by location, and the company has limited ability to quickly replace them without incurring high costs relative to its profits.

Table 10

Operating Efficiency Assessment

Qualifier	What it means	Guidance
Strong	• The company maximizes revenues and profits via intelligent use of assets and by minimizing costs and increasing efficiency. • The company's cost structure should enable it to withstand economic downturns better than its peers.	• The company has a lower cost structure than its peers resulting in higher profits or margins even if capacity utilization or demand are well below ideal levels and during down economic and industry cycles. • It has demonstrated its ability to efficiently manage fixed and variable costs in cyclical downturns, and has a history of successful and often ongoing cost reductions programs. • Its capacity utilization is close to optimal at the peak of the industry cycle and outperforms the industry average over the cycle. • It has demonstrated that it can pass along increases in input costs and we expect this will continue. • It has a very high ability to adjust production and labor costs in response to changes in demand without repercussions for product quality, or has demonstrated the ability to operate very profitably in a more costly or less flexible labor environment. • Its suppliers have demonstrated an ability to meet swings in demand without causing bottlenecks or quality issues, and can absorb all but the most severe supply chain disruptions. • It has superior working capital management, as evidenced by a consistently better-than-average "cash conversion cycle" and other working capital metrics, supporting higher cash flow and lower funding costs. • Its investments in technology are likely to increase revenue growth and/or improve its cost structure and operating efficiency.

Adequate	• A combination of cost structure and efficiency should support sustainable profits with average profit volatility relative to the company's peers. Its cost structure is similar to its peers'.	• The company has demonstrated the ability to manage some fixed and most variable costs except during periods of extremely weak demand, and has some history of cutting costs in good and bad times. • Its cost structure permits some profitability even if capacity utilization or customer demand is well below ideal levels. The company can at least break even during most of the industry/demand cycle. • Its cost structure is in line with its peers'. For example, its selling, general, and administrative (SG&A) expense as a percent of revenue is similar to its peers' and is likely to be stable. • It has demonstrated an ability to adjust labor costs in most scenarios without hurting product output and quality, or can operate profitability in a more costly or less flexible labor environment; it has some success passing on input cost increases, although perhaps only partially or with time lag. • Its suppliers have met typical swings in demand without causing widespread bottlenecks or quality issues, and the company has some capacity to withstand limited supply chain disruptions. • It has good working capital management, evidenced by its cash conversion cycle and working capital metrics that are on par with its peers'. • Its investments in technology are likely to help it at least maintain its cost structure and current level of operating efficiency.
Weak	• The company's operating efficiency leaves it with lower profitability than its peers' due to lower asset utilization and/or a higher, less flexible cost structure.	• The company's cost structure permits better-than-marginal profitability only if capacity utilization is at the top of the cycle or during periods of strong demand. The company needs solid and sustained industry conditions to generate fair profitability. • It has limited success or capability of managing fixed costs and even most typically variable costs are fixed in the next two to three years. • It has a limited track record of successful cost reductions, such as reducing labor costs in the face of swings in demand, or it has limited ability to pass along increases in input costs. • Its costs are higher than its peers'. For example, the company's SG&A expense as a percent of revenue is above that of its peers, and likely to remain so. • Its suppliers may face bottlenecks or quality issues in the event of modest swings in demand, or have limited technological capabilities. There is evidence that a limited supply chain disruption would make it difficult for suppliers to meet their commitments to the company. • Its working capital management is weak, as evidenced by working capital metrics that are significantly worse than those of its peers, resulting in lower cash flow and higher funding costs. • It lacks investments in technology, which could hurt is revenue growth and/or result in a higher cost structure and less efficient operations relative to its peers'.

3. Determining the preliminary competitive position assessment: Competitive position group profile and category weightings

67. After assessing competitive advantage; scale, scope, and diversity; and operating efficiency, we determine a company's preliminary competitive position assessment by ascribing a specific weight to each component. The weightings depend on the company's Competitive Position Group Profile (CPGP).

68. There are six possible CPGPs: 1) services and product focus, 2) product focus/scale driven, 3) capital or asset focus, 4) commodity focus/cost driven, 5) commodity focus/scale driven, and 6) national industry and utilities (see table 11 for definitions and characteristics).

Table 11

Competitive Position Group Profile (CPGP)

	Definition and characteristics	Examples
Services and product focus	Brands, product quality or technology, and service reputation are typically key differentiating factors for competing in the industry. Capital intensity is typically low to moderate, although supporting the brand often requires ongoing reinvestment in the asset base.	Typically, these are companies in consumer-facing light manufacturing or service industries. Examples include branded drug manufacturers, software companies, and packaged food.
Product focus/scale driven	Product and geographic diversity, as well as scale and market position are key differentiating factors. Sophisticated technology and stringent quality controls heighten risk of product concentration. Product preferences or sales relationships are more important than branding or pricing. Cost structure is relatively unimportant.	The sector most applicable is medical device/equipment manufacturers, particularly at the higher end of the technology scale. These companies largely sell through intermediaries, as opposed to directly to the consumer.
Capital or asset focus	Sizable capital investments are generally required to sustain market position in the industry. Brand identification is of limited importance, although product and service quality often remain differentiating factors.	Heavy manufacturing industries typically fall into this category. Examples include telecom infrastructure manufacturers and semiconductor makers.
Commodity focus/cost driven	Cost position and efficiency of production assets are more important than size, scope, and diversification. Brand identification is of limited importance	Typically, these are companies that manufacture products from natural resources that are used as raw materials by other industries. Examples include forest and paper products companies that harvest timber or produce pulp, packaging paper, or wood products.
Commodity focus/scale driven	Pure commodity companies have little product differentiation, and tend to compete on price and availability. Where present, brand recognition or product differences are secondary or of less importance.	Examples range from pure commodity producers and most oil and gas upstream producers, to some producers with modest product or brand differentiation, such as commodity foods.
National industries and utilities	Government policy or control, regulation, and taxation and tariff policies significantly affect the competitive dynamics of the industry (see paragraphs 72-73).	An example is a water-utility company in an emerging market.

69. The nature of competition and key success factors are generally prescribed by industry characteristics, but vary by company. Where service, product quality, or brand equity are important competitive factors, we'll give the competitive advantage component of our overall assessment a higher weighting. Conversely, if the company produces a commodity product, differentiation comes less into play, and we will more heavily weight scale, scope, and diversity as well as operating efficiency (see table 12).

Table 12

Competitive Position Group Profiles (CPGPs) And Category Weightings

Component	--(%)--					
	Services and product focus	**Product focus/scale driven**	**Capital or asset focus**	**Commodity focus/cost driven**	**Commodity focus/scale driven**	**National industries and utilities**
1. Competitive advantage	45	35	30	15	10	60
2. Scale, scope, and diversity	30	50	30	35	55	20
3. Operating efficiency	25	15	40	50	35	20
Total	100	100	100	100	100	100
Weighted-average assessment*	1.0-5.0	1.0-5.0	1.0-5.0	1.0-5.0	1.0-5.0	1.0-5.0

*1 (strong), 2 (strong/adequate), 3 (adequate), 4 (adequate/weak), 5 (weak).

70. We place each of the defined industries (see Appendix B, table 27) into one of the six CPGPs (see above and Appendix B, table 27). This is merely a starting point for the analysis, since we recognize that some industries are less homogenous than others, and that company-specific strategies do affect the basis of competition.

71. In fact, the criteria allow for flexibility in selecting a company's group profile (with its category weightings). Reasons for selecting a profile different than the one suggested in the guidance table could include:

- The industry is heterogeneous, meaning that the nature of competition differs from one subsector to the next, and possibly even within subsectors. The KCF article for the industry will identify such circumstances.
- A company's strategy could affect the relative importance of its key factors of competition.

72. For example, the standard CPGP for the telecom and cable industry is services and product focus. While this may be an appropriate group profile for carriers and service providers, an infrastructure provider may be better analyzed under the capital or asset focus group profile. Other examples: In the capital goods industry, a construction equipment rental company may be analyzed under the capital or asset focus group profile, owing to the importance of efficiently managing the capital spending cycle in this segment of the industry, whereas a provider of hardware, software, and services for industrial automation might be analyzed under the services and product focus group profile, if we believe it can achieve differentiation in the marketplace based on product performance, technology innovation, and service.

73. In some industries, the effects of government policy, regulation, government control, and taxation and tariff policies can significantly alter the competitive dynamics, depending on the country in which a company operates. That can alter our assessment of a company's competitive advantage; scale, size, and diversity; or operating efficiency. When industries in given countries have risks that differ materially from those captured in our global industry risk profile and assessment (see "Methodology: Industry Risk," published Nov. 19, 2013, section B), we will weight competitive advantage more heavily to capture the effect, positive or negative, on competitive dynamics. The assessment of competitive advantage; scale, size, and diversity; and operating efficiency will reflect advantages or disadvantages based on these national industry risk factors. Table 13 identifies the circumstances under which national industry risk factors are positive or negative.

Table 13

National Industry Risk Factors

National industry risk factors are positive	• Government policy including regulation, ownership, and taxation is supportive and has a good track record of mitigating risks to the stability of industry margins. • Any government ownership, tariff, and taxation policy supports growth prospects for revenues and profit generation. • There is very little discernible risk of negative policy, regulatory, ownership, or taxation changes that could threaten business stability.
National industry risk factors are negative	• Government policy and regulation has a weak track record of stabilizing margins and reducing industry risks. • Any government ownership, tariff, and taxation policy undermine growth prospects for revenues and profit generation. • There is an increasing risk of negative policy, ownership, and taxation changes that could undermine industry stability.

74. When national industry risk factors are positive for a company, typically they support revenue growth, profit growth, higher EBITDA margins, and/or lower-than-average volatility of profits. Often, these benefits provide barriers to entry that impede or even bar new market entrants, which should be reflected in the competitive advantage assessment. These benefits may also include risk mitigants that enable a company to withstand economic downturns and competitive and technological threats better in its local markets than its global competitors can. The scale, scope, and diversity assessment might also benefit from these policies if the company is able to withstand economic, regional, competitive, and technological threats better than its global competitors can. Likewise, the company's operating efficiency assessment may improve if, as a result, it is better able than its global competitors to withstand economic downturns, taking into account its cost structure.

75. Conversely, when national industry risk factors are negative for a company, typically they detract from revenue growth and profit growth, shrink EBITDA margins, and/or increase the average volatility of profits. The company may also have less protection against economic downturns and competitive and technological threats within its local markets than its global competitors do. We may also adjust the company's scale, scope, and diversity assessment lower if, as a result of these policies, it is less able to withstand economic, regional, competitive, and technological threats than its global competitors can. Likewise, we may adjust its operating efficiency assessment lower if, as a result of these policies, it is less able to withstand economic downturns, taking into account the company's cost structure.

76. An example of when we might use a national industry risk factor would be for a telecommunications network owner that benefits from a monopoly network position, supported by substantial capital barriers to entry, and as a result is subject to regulated pricing for its services. Accordingly, in contrast to a typical telecommunications company, our analysis of the company's competitive position would focus more heavily on the monopoly nature of its operations, as well as the nature and reliability of the operator's regulatory framework in supporting future revenue and earnings. If we viewed the regulatory framework as being supportive of the group's future earnings stability, and we considered its

monopoly position to be sustainable, we would assess these national industry risk factors as positive in our assessment of the group's competitive position.

77. The weighted average assessment translates into the preliminary competitive position assessment on a scale of 1 to 6, where one is best. Table 14 describes the matrix we use to translate the weighted average assessment of the three components into the preliminary competitive position assessment.

Table 14

Translation Table For Converting Weighted-Average Assessments Into Preliminary Competitive Position Assessments

Weighted average assessment range	Preliminary competitive position assessment
1.00 – 1.50	1
>1.50 – 2.25	2
>2.25 – 3.00	3
>3.00 – 3.75	4
>3.75 – 4.50	5
>4.50 – 5.00	6

4. Assessing profitability

78. We assess profitability on the same scale of 1 to 6 as the competitive position assessment.

79. The profitability assessment consists of two subcomponents: level of profitability and the volatility of profitability, which we assess separately. We use a matrix to combine these into the final profitability assessment.

a) Level of profitability

80. The level of profitability is assessed in the context of the company's industry. We most commonly measure profitability using return on capital (ROC) and EBITDA margins, but we may also use sector-specific ratios. Importantly, as with the other components of competitive position, we review profitability in the context of the industry in which the company operates, not just in its narrower subsector. (See list of industries and subsectors in Appendix B, table 27.)

81. We assess level of profitability on a three-point scale: above average, average, and below average. Industry KCF articles may establish numeric guidance, for instance by stating that an ROC above 12% is considered above average, between 8%-12% is average, and below 8% is below average for the industry, or by differentiating between subsectors in the industry. In the absence of numeric guidance, we compare a company against its peers across the industry.

82. We calculate profitability ratios generally based on a five-year average, consisting of two years of historical data, our projections for the current year (incorporating any reported year-to-date results and estimates for the remainder of the year), and the next two financial years. There may be situations where we consider longer or shorter historical results or forecasts, depending on such factors as availability of financials, transformational events (such as mergers or acquisitions [M&A]), cyclical distortion (such as peak or bottom of the cycle metrics that we do not deem fully representative of the company's level of profitability), and we take into account improving or deteriorating trends in profitability ratios in our assessment.

b) Volatility of profitability

83. We base the volatility of profitability on the standard error of the regression (SER) for a company's historical EBITDA, EBITDA margins, or return on capital. The KCF articles provide guidance on which measures are most appropriate for a given industry or set of companies. For each of these measures, we divide the standard error by the average of that measure over the time period in order to ensure better comparability across companies.

84. The SER is a statistical measure that is an estimate of the deviation around a 'best fit' linear trend line. We regress the company's EBITDA, EBITDA margins, or return on capital against time. A key advantage of SER over standard deviation or coefficient of variation is that it doesn't view upwardly trending data as inherently more volatile. At the same time, we recognize that SER, like any statistical measure, may understate or overstate expected volatility and thus we will make qualitative adjustments where appropriate (see paragraphs 86-90). Furthermore, we only calculate SER when companies have at least seven years of historical annual data and have not significantly changed their line of business during the timeframe, to ensure that the results are meaningful.

85. As with the level of profitability, we evaluate a company's SER in the context of its industry group. For most industries, we establish a six-point scale with 1 capturing the least volatile companies, i.e., those with the lowest SERs, and 6 identifying companies whose profits are most volatile. We have established industry-specific SER parameters using the most recent seven years of data for companies within each sector. We believe that seven years is generally an adequate number of years to capture a business cycle. (See Appendix B, section 4 for industry-specific SER parameters.) For companies whose business segments cross multiple industries, we evaluate the SER in the context of the organization's most dominant industry--if that industry represents at least two-thirds of the organization's EBITDA, sales, or other relevant metric. If the company is a conglomerate and no dominant industry can be identified, we will evaluate its profit volatility in the context of SER guidelines for all nonfinancial companies.

86. In certain circumstances, the SER derived from historical information may understate--or overstate--expected future volatility, and we may adjust the assessment downward or upward. The scope of possible adjustments depends on certain conditions being met as described below.

87. We might adjust the SER-derived volatility assessment to a worse assessment (i.e., to a higher assessment for greater volatility) by up to two categories if the expected level of volatility isn't apparent in historical numbers, and the company either:

- Has a weighted country risk assessment of 4 or worse, which may, notwithstanding past performance, result in a less stable business environment going forward;
- Operates in a subsector of the industry that may be prone to higher technology or regulation changes, or other potential disruptive risks that have not emerged over the seven year period;
- Is of limited size and scope, which will often result in inherently greater vulnerability to external changes; or
- Has pursued material M&A or internal growth projects that obscure the company's underlying performance trend line. As an example, a company may have consummated an acquisition during the trough of the cycle, masking what would otherwise be a significant decline in performance.

88. The choice of one or two categories depends on the degree of likelihood that the related risks will materialize and our view of the likely severity of these risks.

89. Conversely, we may adjust the SER-derived volatility assessment to a better assessment (i.e., to a lower assessment reflecting lower volatility) by up to two categories if we observe that the conditions historically leading to greater volatility have receded and are misrepresentative. This will be the case when:

- The company grew at a moderately faster, albeit more uneven, pace relative to the industry. Since we measure volatility around a linear trend line, a company growing at a constant percentage of moderate increase (relative to the industry) or an uneven pace (e.g., due to "lumpy" capital spending programs) could receive a relatively unfavorable assessment on an unadjusted basis, which would not be reflective of the company's performance in a steady state. (Alternatively, those companies that grow at a significantly higher-than-average industry rate often do so on unsustainable rates of growth or by taking on high-risk strategies. Companies with these high-risk growth strategies would not receive a better assessment and could be adjusted to a worse assessment;)
- The company's geographic, customer, or product diversification has increased in scope as a result of an acquisition or rapid expansion (e.g. large, long-term contracts wins), leading to more stability in future earnings in our view; or
- The company's business model is undergoing material change that we expect will benefit earnings stability, such as a new regulatory framework or major technology shift that is expected to provide a significant competitive hedge and margin protection over time.

90. The choice of one or two categories depends on the degree of likelihood that the related risks will materialize and our view of the likely severity of these risks.

91. If the company either does not have at least seven years of annual data or has materially changed its business lines or undertaken abnormally high levels of M&A during this time period, then we do not use its SER to assess the volatility of profitability. In these cases, we use a proxy to establish the volatility assessment. If there is a peer company that has, and is expected to continue having, very similar profitability volatility characteristics, we use the SER of that peer entity as a proxy.

92. If no such matching peer exists, or one cannot be identified with enough confidence, we perform an assessment of expected volatility based on the following rules:

- An assessment of 3 if we expect the company's profitability, supported by available historical evidence, will exhibit a volatility pattern in line with, or somewhat less volatile than, the industry average.
- An assessment of 2 based on our confidence, supported by available historical evidence, that the company will exhibit lower volatility in profitability metrics than the industry's average. This could be underpinned by some of the factors listed in paragraph 89, whereas those listed in paragraph 87 would typically not apply.
- An assessment of 4 or 5 based on our expectation that profitability metrics will exhibit somewhat higher (4), or meaningfully higher (5) volatility than the industry, supported by available historical evidence, or because of the applicability of possible adjustment factors listed in paragraph 87.
- Assessments of either 1 or 6 are rarely assigned and can only be achieved based on a combination of data evidence and very high confidence tests. For an assessment of 1, we require strong evidence of minimal volatility in profitability metrics compared with the industry, supported by at least five years of historical information, combined with a very high degree of confidence that this will continue in the future, including no country risk, subsector risk or size considerations that could otherwise warrant a worse assessment as per paragraph 87. For an assessment of 6 we require strong evidence of very high volatility in profitability metrics compared with the industry, supported by at least five years of historical information and very high confidence that this will continue in the future.

93. Next, we combine the level of profitability assessment with the volatility assessment to determine the final profitability

assessment using the matrix in Table 15.

Table 15

Profitability Assessment

	--Volatility of profitability assessment--					
Level of profitability assessment	**1**	**2**	**3**	**4**	**5**	**6**
Above average	1	1	2	3	4	5
Average	1	2	3	4	5	6
Below average	2	3	4	5	6	6

5. Combining the preliminary competitive position assessment with profitability

94. The fourth and final step in arriving at a competitive position assessment is to combine the preliminary competitive position assessment with the profitability assessment. We use the combination matrix in Table 16, which shows how the profitability assessment can confirm, strengthen, or weaken (by up to one category) the overall competitive position assessment.

Table 16

Combining The Preliminary Competitive Position Assessment And Profitability Assessment

	--Preliminary competitive position assessment--					
Profitability assessment	**1**	**2**	**3**	**4**	**5**	**6**
1	1	2	2	3	4	5
2	1	2	3	3	4	5
3	2	2	3	4	4	5
4	2	3	3	4	5	5
5	2	3	4	4	5	6
6	2	3	4	5	5	6

95. We generally expect companies with a strong preliminary competitive position assessment to exhibit strong and less volatile profitability metrics. Conversely, companies with a relatively weaker preliminary competitive position assessment will generally have weaker and/or more volatile profitability metrics. Our analysis of profitability helps substantiate whether management is translating any perceived competitive advantages, diversity benefits, and cost management measures into higher earnings and more stable return on capital and return on sales ratios than the averages for the industry. When profitability differs markedly from what the preliminary/anchor competitive position assessment would otherwise imply, we adjust the competitive position assessment accordingly.

96. Our method of adjustment is biased toward the preliminary competitive position assessment rather than toward the profitability assessment (e.g., a preliminary competitive assessment of 6 and a profitability assessment of 1 will result in a final assessment of 5).

E. Cash Flow/Leverage

97. The pattern of cash flow generation, current and future, in relation to cash obligations is often the best indicator of a company's financial risk. The criteria assess a variety of credit ratios, predominately cash flow-based, which

complement each other by focusing on the different levels of a company's cash flow waterfall in relation to its obligations (i.e., before and after working capital investment, before and after capital expenditures, before and after dividends), to develop a thorough perspective. Moreover, the criteria identify the ratios that we think are most relevant to measuring a company's credit risk based on its individual characteristics and its business cycle.

98. For the analysis of companies with intermediate or stronger cash flow/leverage assessments (a measure of the relationship between the company's cash flows and its debt obligations as identified in paragraphs 106 and 124), we primarily evaluate cash flows that reflect the considerable flexibility and discretion over outlays that such companies typically possess. For these entities, the starting point in the analysis is cash flows before working capital changes plus capital investments in relation to the size of a company's debt obligations in order to assess the relative ability of a company to repay its debt. These "leverage" or "payback" cash flow ratios are a measure of how much flexibility and capacity the company has to pay its obligations.

99. For entities with significant or weaker cash flow/leverage assessments (as identified in paragraphs 105 and 124), the criteria also call for an evaluation of cash flows in relation to the carrying cost or interest burden of a company's debt. This will help us assess a company's relative and absolute ability to service its debt. These "coverage"- or "debt service"-based cash flow ratios are a measure of a company's ability to pay obligations from cash earnings and the cushion the company possesses through stress periods. These ratios, particularly interest coverage ratios, become more important the further a company is down the credit spectrum.

1. Assessing cash flow/leverage

100. Under the criteria, we assess cash flow/leverage as 1, minimal; 2, modest; 3, intermediate; 4, significant; 5, aggressive; or 6, highly leveraged. To arrive at these assessments, the criteria combine the assessments of a variety of credit ratios, predominately cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations. For each ratio, there is an indicative cash flow/leverage assessment that corresponds to a specified range of values in one of three given benchmark tables (see tables 17, 18, and 19). We derive the final cash flow/leverage assessment for a company by determining the relevant core ratios, anchoring a preliminary cash flow assessment based on the relevant core ratios, determining the relevant supplemental ratio(s), adjusting the preliminary cash flow assessment according to the relevant supplemental ratio(s), and, finally, modifying the adjusted cash flow/leverage assessment for any material volatility.

2. Core and supplemental ratios

a) Core ratios

101. For each company, we calculate two core credit ratios--funds from operations (FFO) to debt and debt to EBITDA--in accordance with Standard & Poor's ratios and adjustments criteria (see "Corporate Methodology: Ratios And Adjustments," published Nov. 19, 2013). We compare these payback ratios against benchmarks to derive the preliminary cash flow/leverage assessment for a company. These ratios are also useful in determining the relative ranking of the financial risk of companies.

b) Supplemental ratios

102. The criteria also consider one or more supplemental ratios (in addition to the core ratios) to help develop a fuller understanding of a company's financial risk profile and fine-tune our cash flow/leverage analysis. Supplemental ratios

could either confirm or adjust the preliminary cash flow/leverage assessment. The confirmation or adjustment of the preliminary cash flow/leverage assessment will depend on the importance of the supplemental ratios as well as any difference in indicative cash flow/leverage assessment between the core and supplemental ratios as described in section E.3.b.

103. The criteria typically consider five standard supplemental ratios, although the relevant KCF criteria may introduce additional supplemental ratios or focus attention on one or more of the standard supplemental ratios. The standard supplemental ratios include three payback ratios--cash flow from operations (CFO) to debt, free operating cash flow (FOCF) to debt, and discretionary cash flow (DCF) to debt--and two coverage ratios, FFO plus interest to cash interest and EBITDA to interest.

104. The criteria provide guidelines as to the relative importance of certain ratios if a company exhibits characteristics such as high leverage, working capital intensity, capital intensity, or high growth.

105. If the preliminary cash flow/leverage assessment is significant or weaker (see section E.3), then two coverage ratios, FFO plus interest to cash interest and EBITDA to interest, will be given greater importance as supplemental ratios. For the purposes of calculating the coverage ratios, "cash interest" includes only cash interest payments (i.e., interest excludes noncash interest payable on, for example, payment-in-kind [PIK] instruments) and does not include any Standard & Poor's adjusted interest on such items as leases, while "interest" is the income statement figure plus Standard & Poor's adjustments to interest (see "Corporate Methodology: Ratios And Adjustments," published Nov. 19, 2013).

106. If the preliminary cash flow/leverage assessment is intermediate or stronger, the criteria first apply the three standard supplemental ratios of CFO to debt, FOCF to debt, and DCF to debt. When FOCF to debt and DCF to debt indicate a cash flow/leverage assessment that is lower than the other payback-ratio-derived cash flow/leverage assessments, it signals that the company has either larger than average capital spending or other non-operating cash distributions (including dividends). If these differences persist and are consistent with a negative trend in overall ratio levels, which we believe is not temporary, then these supplemental leverage ratios will take on more importance in the analysis.

107. If the supplemental ratios indicate a cash flow/leverage assessment that is different than the preliminary cash flow/leverage assessment, it could suggest an unusual debt service or fixed charge burden, working capital or capital expenditure profile, or unusual financial activity or policies. In such cases, we assess the sustainability or persistence of these differences. For example, if either working capital or capital expenditures are unusually low, leading to better indicated assessments, we examine the sustainability of such lower spending in the context of its impact on the company's longer term competitive position. If there is a deteriorating trend in the company's asset base, we give these supplemental ratios less weight. If either working capital or capital expenditures are unusually high, leading to weaker indicated assessments, we examine the persistence and need for such higher spending. If elevated spending levels are required to maintain a company's competitive position, for example to maintain the company's asset base, we give more weight to these supplemental ratios.

108. For capital-intensive companies, EBITDA and FFO may overstate financial strength, whereas FOCF may be a more accurate reflection of their cash flow in relation to their financial obligations. The criteria generally consider a

capital-intensive company as having ongoing capital spending to sales of greater than 10%, or depreciation to sales of greater than 8%. For these companies, the criteria place more weight on the supplementary ratio of FOCF to debt. Where we place more analytic weight on FOCF to debt, we also seek to estimate the amount of maintenance or full cycle capital required (see Appendix C) under normal conditions (we estimate maintenance or full-cycle capital expenditure required because this is not a reported number). The FOCF figure may be adjusted by adding back estimated discretionary capital expenditures. The adjusted FOCF to debt based on maintenance or full cycle capital expenditures often helps determine how much importance to place on this ratio. If both the FOCF to debt and the adjusted (for estimated discretionary capital spending) FOCF to debt derived assessments are different from the preliminary cash/flow leverage assessment, then these supplemental leverage ratios take on more importance in the analysis.

109. For working-capital-intensive companies, EBITDA and FFO may also overstate financial strength, and CFO may be a more accurate measure of the company's cash flow in relation to its financial risk profile. Under the criteria, if a company has a working capital-to-sales ratio that exceeds 25% or if there are significant seasonal swings in working capital, we generally consider it to be working-capital-intensive. For these companies, the criteria place more emphasis on the supplementary ratio of CFO to debt. Examples of companies that have working-capital-intensive characteristics can be found in the capital goods, metals and mining downstream, or the retail and restaurants industries. The need for working capital in those industries reduces financial flexibility and, therefore, these supplemental leverage ratios take on more importance in the analysis.

110. For all companies, when FOCF to debt or DCF to debt is negative or indicates materially lower cash flow/leverage assessments, the criteria call for an examination of management's capital spending and cash distribution strategies. For high-growth companies, typically the focus is on FFO to debt instead of FOCF to debt because the latter ratio can vary greatly depending on the growth investment the company is undergoing. The criteria generally consider a high-growth company one that exhibits real revenue growth in excess of 8% per year. Real revenue growth excludes price or foreign exchange related growth, under these criteria. In cases where FOCF or DCF is low, there is a greater emphasis on monitoring the sustainability of margins and return on capital and the overall financing mix to assess the likely trend of future debt ratios. In addition, debt service ratio analysis will be important in such situations. For companies with more moderate growth, the focus is typically on FOCF to debt unless the capital spending is short term or is not funded with debt.

111. For companies that have ongoing and well entrenched banking relationships we can reflect these relationships in our cash flow/leverage analysis through the use of the interest coverage ratios as supplemental ratios. These companies generally have historical links and a strong ongoing relationship with their main banks, as well as shareholdings by the main banks, and management influence and interaction between the main banks and the company. Based on their bank relationships, these companies often have lower interest servicing costs than peers, even if the macro economy worsens. In such cases, we generally use the interest coverage ratios as supplemental ratios. This type of banking relationship occurs in Japan, for example, where companies that have the type of bank relationship described in this paragraph tend to have a high socioeconomic influence within their country by way of their revenue size, total debt quantum, number of employees, and the relative importance of the industry.

c) Time horizon and ratio calculation

112. A company's credit ratios may vary, often materially, over time due to economic, competitive, technological, or investment cycles, the life stage of the company, and corporate or strategic actions. Thus, we evaluate credit ratios on a time series basis with a clear forward-looking bias. The length of the time series is dependent on the relative credit risk of the company and other qualitative factors and the weighting of the time series varies according to transformational events. A transformational event is any event that could cause a material change in a company's financial profile, whether caused by changes to the company's capital base, capital structure, earnings, cash flow profile, or financial policies. Transformational events can include mergers, acquisitions, divestitures, management changes, structural changes to the industry or competitive environment, and/or product development and capital programs. This section provides guidance on the timeframe and weightings the criteria apply to calculate the indicative ratios.

113. The criteria generally consider the company's credit ratios for the previous one to two years, current-year forecast, and the two subsequent forecasted financial years. There may be situations where longer--or even shorter--historical results or forecasts are appropriate, depending on such factors as availability of financials, transformational events, or relevance. For example, a utility company with a long-term capital spending program may lend itself to a longer-term forecast, whereas for a company experiencing a near-term liquidity squeeze even a two-year forecast will have limited value. Alternatively, for most commodities-based companies we emphasize credit ratios based on our forward-looking view of market conditions, which may differ materially from the historical period.

114. Historical patterns in cash flow ratios are informative, particularly in understanding past volatility, capital spending, growth, accounting policies, financial policies, and business trends. Our analysis starts with a review of these historical patterns in order to assess future expected credit quality. Historical patterns can also provide an indication of potential future volatility in ratios, including that which results from seasonality or cyclicality. A history of volatility could result in a more conservative assessment of future cash flow generation if we believe cash flow will continue to be volatile.

115. The forecast ratios are based on an expected base-case scenario developed by Standard & Poor's, incorporating current and near-term economic conditions, industry assumptions, and financial policies. The prospective cyclical and longer-term volatility associated with the industry in which the issuer operates is addressed in the industry risk criteria (see section B) and the longer-term directional influence or event risk of financial policies is addressed in our financial policy criteria (see section H).

116. The criteria generally place greater emphasis on forecasted years than historical years in the time series of credit ratios when calculating the indicative credit ratio. For companies where we have five years of ratios as described in section E.3, generally we calculate the indicative ratio by weighting the previous two years, the current year, and the forecasted two years as 10%, 15%, 25%, 25%, and 25%, respectively.

117. This weighting changes, however, to place even greater emphasis on the current and forecast years when:

- The issuer meets the characteristics described in paragraph 113, and either shorter- or longer-term forecasts are applicable. The weights applied will generally be quite forward weighted, particularly if a company is undergoing a transformational event and there is moderate or better cash flow certainty.
- The issuer is forecast to generate negative cash flow available for debt repayment, which we believe could lead to

deteriorating credit metrics. Forecast negative cash flows could be generated from operating activities as well as capital expenditures, share buybacks, dividends, or acquisitions, as we forecast these uses of cash based on the company's track record, market conditions, or financial policy. The weights applied will generally be 30%, 40%, and 30% for the current and two subsequent years, respectively.

- The issuer is in an industry that is prospectively volatile or that has a high degree of cash flow uncertainty. Industries that are prospectively volatile are industries whose competitive risk and growth assessments are either high risk (5) or very high risk (6) or whose overall industry risk assessments are either high risk (5) or very high risk (6). The weights applied will generally be 50% for the current year and 50% for the first subsequent forecast year.

118. When the indicative ratio(s) is borderline (i.e., less than 10% different from the threshold in relative terms) between two assessment thresholds (as described in section E.3 and tables 17, 18, and 19) and the forecast points to a switch in the ratio between categories during the rating timeframe, we will weigh the forecast even more heavily in order to prospectively capture the trend.

119. For companies undergoing a transformational event, the weighting of the time series could vary significantly.

120. For companies undergoing a transformational event and with significant or weaker cash flow/leverage assessments, we place greater weight on near-term risk factors. That's because overemphasis on longer-term (inherently less predictable) issues could lead to some distortion when assessing the risk level of a speculative-grade company. We generally analyze a company using the arithmetic mean of the credit ratios expected according to our forecasts for the current year (or pro forma current year) and the subsequent financial year. A common example of this is when a private equity firm acquires a company using additional debt leverage, which makes historical financial ratios meaningless. In this scenario, we weight or focus the majority of our analysis on the next one or two years of projected credit measures.

3. Determining the cash flow/leverage assessment

a) Identifying the benchmark table

121. Tables 17, 18, and 19 provide benchmark ranges for various cash flow ratios we associate with different cash flow/leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow/leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

122. If an industry exhibits low volatility, the threshold levels for the applicable ratios to achieve a given cash flow/leverage assessment are less stringent than those in the medial or standard volatility tables, although the range of the ratios is narrower. Conversely, if an industry exhibits medial or standard levels of volatility, the threshold for the applicable ratios to achieve a given cash flow/leverage assessment are elevated, albeit with a wider range of values.

123. The relevant benchmark table for a given company is based on our assessment of the company's associated industry and country risk volatility, or the CICRA (see section A, table 1). The low volatility table (table 19) will generally apply when a company's CICRA is 1, unless otherwise indicated in a sector's KCF criteria. The medial volatility table (table 18) will be used under certain circumstances for companies with a CICRA of 1 or 2. Those circumstances are described in the respective sectors' KCF criteria. The standard volatility table (table 17) serves as the relevant benchmark table for companies with a CICRA of 2 or worse, and we will always use it for companies with a CICRA of 1 or 2 and whose competitive position is assessed 5 or 6. Although infrequent, we will use the low volatility table when

a company's CICRA is 2 for companies that exhibit or are expected to exhibit low levels of volatility. The choice of volatility tables for companies with a CICRA of 2 is addressed in the respective sector's KCF article.

Table 17

Cash Flow/Leverage Analysis Ratios--Standard Volatility

	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	**Debt/EBITDA (x)**	**FFO/cash interest(x)**	**EBITDA/interest (x)**	**CFO/debt (%)**	**FOCF/debt (%)**	**DCF/debt (%)**
Minimal	60+	Less than 1.5	More than 13	More than 15	More than 50	40+	25+
Modest	45-60	1.5-2	9-13	10-15	35-50	25-40	15-25
Intermediate	30-45	2-3	6-9	6-10	25-35	15-25	10-15
Significant	20-30	3-4	4-6	3-6	15-25	10-15	5-10
Aggressive	12-20	4-5	2-4	2-3	10-15	5-10	2-5
Highly leveraged	Less than 12	Greater than 5	Less than 2	Less than 2	Less than 10	Less than 5	Less than 2

Table 18

Cash Flow/Leverage Analysis Ratios--Medial Volatility

	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	**Debt/EBITDA (x)**	**FFO/cash interest (x)**	**EBITDA/interest (x)**	**CFO/debt (%)**	**FOCF/debt (%)**	**DCF/debt (%)**
Minimal	50+	less than 1.75	10.5+	14+	40+	30+	18+
Modest	35-50	1.75-2.5	7.5-10.5	9-14	27.5-40	17.5-30	11-18
Intermediate	23-35	2.5-3.5	5-7.5	5-9	18.5-27.5	9.5-17.5	6.5-11
Significant	13-23	3.5-4.5	3-5	2.75-5	10.5-18.5	5-9.5	2.5-6.5
Aggressive	9-13	4.5-5.5	1.75-3	1.75-2.75	7-10.5	0-5	(11)-2.5
Highly leveraged	Less than 9	Greater than 5.5	Less than 1.75	Less than 1.75	Less than 7	Less than 0	Less than (11)

Table 19

Cash Flow/Leverage Analysis Ratios--Low Volatility

	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	**Debt/EBITDA (x)**	**FFO/cash interest (x)**	**EBITDA/interest (x)**	**CFO/debt (%)**	**FOCF/debt (%)**	**DCF/debt (%)**
Minimal	35+	Less than 2	More than 8	More than 13	More than 30	20+	11+
Modest	23-35	2-3	5-8	7-13	20-30	10-20	7-11
Intermediate	13-23	3-4	3-5	4-7	12-20	4-10	3-7
Significant	9-13	4-5	2-3	2.5-4	8-12	0-4	0-3
Aggressive	6-9	5-6	1.5-2	1.5-2.5	5-8	(10)-0	(20)-0
Highly leveraged	Less than 6	Greater than 6	Less than 1.5	Less than 1.5	Less than 5	Less than (10)	Less than (20)

b) Aggregating the credit ratio assessments

124. To determine the final cash flow/leverage assessment, we make these calculations:
1) First, calculate a time series of standard core and supplemental credit ratios, select the relevant benchmark table, and determine the appropriate time weighting of the credit ratios.

- Calculate the two standard core credit ratios and the five standard supplemental credit ratios over a five-year time horizon.
- Consult the relevant industry KCF article (if applicable), which may identify additional supplemental ratio(s). The relevant benchmark table for a given company is based on our assessment of the company's associated industry and country risk volatility, or the CICRA.
- Calculate the appropriate weighted average cash flow/leverage ratios. If the company is undergoing a transformational event, then the core and supplemental ratios will typically be calculated based on Standard & Poor's projections for the current and next one or two financial years.

2) Second, we use the core ratios to determine the preliminary cash flow assessment.

- Compare the core ratios (FFO to debt and debt to EBITDA) to the ratio ranges in the relevant benchmark table.
- If the core ratios result in different cash flow/leverage assessments, we will select the relevant core ratio based on which provides the best indicator of a company's future leverage.

3) Third, we review the supplemental ratio(s).

- Determine the importance of standard or KCF supplemental ratios based on company-specific characteristics, namely, leverage, capital intensity, working capital intensity, growth rate, or industry.

4) Fourth, we calculate the adjusted cash flow/leverage assessment.

- If the cash flow/leverage assessment(s) indicated by the important supplemental ratio(s) differs from the preliminary cash flow/leverage assessment, we might adjust the preliminary cash flow/leverage assessment by one category in the direction of the cash flow/leverage assessment indicated by the supplemental ratio(s) to derive the adjusted cash flow/leverage assessment. We will make this adjustment if, in our view, the supplemental ratio provides the best indicator of a company's future leverage.
- If there is more than one important supplemental ratio and they result in different directional deviations from the preliminary cash flow/leverage assessment, we will select one as the relevant supplemental ratio based on which, in our opinion, provides the best indicator of a company's future leverage. We will then make the adjustment outlined above if the selected supplemental ratio differs from the preliminary cash flow/leverage assessment and the selected supplemental ratio provides the best overall indicator of a company's future leverage.

5) Lastly, we determine the final cash flow/leverage assessment based on the volatility adjustment.

- We classify companies as stable for these cash flow criteria if cash flow/leverage ratios are expected to move up by one category during periods of stress based on their business risk profile. The final cash flow/leverage assessment for these companies will not be modified from the adjusted cash flow/leverage assessment.
- We classify companies as volatile for these cash flow criteria if cash flow/leverage ratios are expected to move one or two categories worse during periods of stress based on their business risk profiles. Typically, this is equivalent to EBITDA declining about 30% from its current level. The final cash flow/leverage assessment for these companies will be modified to one category weaker than the adjusted cash flow/leverage assessment; the adjustment will be eliminated if cash flow/leverage ratios, as evaluated, include a moderate to high level of stress already.
- We classify companies as highly volatile for these cash flow criteria if cash flow/leverage ratios are expected to move two or three categories worse during periods of stress, based on their business risk profiles. Typically, this is equivalent to EBITDA declining about 50% from its current level. The final cash flow/leverage assessment for these companies will be modified to two categories weaker than the adjusted cash flow/leverage assessment; the adjustment will be eliminated or reduced to one category if cash flow/leverage ratios, as evaluated, include a moderate to high level of stress already.

125. The volatility adjustment is the mechanism by which we factor a "cushion" of medium-term variance to current financial performance not otherwise captured in either the near-term base-case forecast or the long-term business risk

assessment. We make this adjustment based on the following:

- The expectation of any potential cash flow/leverage ratio movement is both prospective and dependent on the current business or economic conditions.
- Stress scenarios include, but are not limited to, a recessionary economic environment, technology or competitive shifts, loss or renegotiation of major contracts or customers, and key product or input price movements, as typically defined in the company's industry risk profile and competitive position assessment.
- The volatility adjustment is not static and is company specific. At the bottom of an economic cycle or during periods of stressed business conditions, already reflected in the general industry risk or specific competitive risk profile, the prospect of weakening ratios is far less than at the peak of an economic cycle or business conditions.
- The expectation of prospective ratio changes may be formed by observed historical performance over an economic, business, or product cycle by the company or by peers.
- The assessment of which classification to use when evaluating the prospective number of scoring category moves will be guided by how close the current ratios are to the transition point (i.e. "buffer" in the current scoring category) and the corresponding amount of EBITDA movement at each scoring transition.

F. Diversification/Portfolio Effect

126. Under the criteria, diversification/portfolio effect applies to companies that we regard as conglomerates. They are companies that have multiple core business lines that may be operated as separate legal entities. For the purpose of these criteria, a conglomerate would have at least three business lines, each contributing a material source of earnings and cash flow.

127. The criteria aim to measure how diversification or the portfolio effect could improve the anchor of a company with multiple business lines. This approach helps us determine how the credit strength of a corporate entity with a given mix of business lines could improve based on its diversity. The competitive position factor assesses the benefits of diversity within individual lines of business. This factor also assesses how poorly performing businesses within a conglomerate affect the organization's overall business risk profile.

128. Diversification/portfolio effect could modify the anchor depending on how meaningful we think the diversification is, and on the degree of correlation we find in each business line's sensitivity to economic cycles. This assessment will have either a positive or neutral impact on the anchor. We capture any potential factor that weakens a company's diversification, including poor management, in our management and governance assessment.

129. We define a conglomerate as a diversified company that is involved in several industry sectors. Usually the smallest of at least three distinct business segments/lines would contribute at least 10% of either EBITDA or FOCF and the largest would contribute no more than 50% of EBITDA or FOCF, with the long-term aim of increasing shareholder value by generating cash flow. Industrial conglomerates usually hold a controlling stake in their core businesses, have highly identifiable holdings, are deeply involved in the strategy and management of their operating companies, generally do not frequently roll over or reshuffle their holdings by buying and selling companies, and therefore have high long-term exposure to the operating risks of their subsidiaries.

130. In rating a conglomerate, we first assess management's commitment to maintain the diversified portfolio over a

longer-term horizon. These criteria apply only if the company falls within our definition of a conglomerate.

1. Assessing diversification/portfolio effect

131. A conglomerate's diversification/portfolio effect is assessed as 1, significant diversification; 2, moderate diversification; or 3, neutral. An assessment of moderate diversification or significant diversification potentially raises the issuer's anchor. To achieve an assessment of significant diversification, an issuer should have uncorrelated diversified businesses whose breadth is among the most comprehensive of all conglomerates'. This assessment indicates that we expect the conglomerate's earnings volatility to be much lower through an economic cycle than an undiversified company's. To achieve an assessment of moderate diversification, an issuer typically has a range of uncorrelated diversified businesses that provide meaningful benefits of diversification with the expectation of lower earnings volatility through an economic cycle than an undiversified company's.

132. We expect that a conglomerate will also benefit from diversification if its core assets consistently produce positive cash flows over our rating horizon. This supports our assertion that the company diversifies to take advantage of allocating capital among its business lines. To this end, our analysis focuses on a conglomerate's track record of successfully deploying positive discretionary cash flow into new business lines or expanding capital-hungry business lines. We assess companies that we do not expect to achieve these benefits as neutral.

2. Components of correlation and how it is incorporated into our analysis

133. We determine the assessment for this factor based on the number of business lines in separate industries (as described in table 27) and the degree of correlation between these business lines as described in table 20. There is no rating uplift for an issuer with a small number of business lines that are highly correlated. By contrast, a larger number of business lines that are not closely correlated provide the maximum rating uplift.

Table 20

Assessing Diversification/Portfolio Effect

	--Number of business lines--		
Degree of correlation of business lines	**3**	**4**	**5 or more**
High	Neutral	Neutral	Neutral
Medium	Neutral	Moderately diversified	Moderately diversified
Low	Moderately diversified	Significantly diversified	Significantly diversified

134. The degree of correlation of business lines is high if the business lines operate within the same industry, as defined by the industry designations in Appendix B, table 27. The degree of correlation of business lines is medium if the business lines operate within different industries, but operate within the same geographic region (for further guidance on defining geographic regions, see Appendix A, table 26). An issuer has a low degree of correlation across its business lines if these business lines are both a) in different industries and b) either operate in different regions or operate in multiple regions.

135. If we believe that a conglomerate's various industry exposures fail to provide a partial hedge against the consolidated entity's volatility because they are highly correlated through an economic cycle, then we assess the diversification/portfolio effect as neutral.

G. Capital Structure

136. Standard & Poor's uses its capital structure criteria to assess risks in a company's capital structure that may not show up in our standard analysis of cash flow/leverage. These risks may exist as a result of maturity date or currency mismatches between a company's sources of financing and its assets or cash flows. These can be compounded by outside risks, such as volatile interest rates or currency exchange rates.

1. Assessing capital structure

137. Capital structure is a modifier category, which adjusts the initial anchor for a company after any modification due to diversification/portfolio effect. We assess a number of subfactors to determine the capital structure assessment, which can then raise or lower the initial anchor by one or more notches--or have no effect in some cases. We assess capital structure as 1, very positive; 2, positive; 3, neutral; 4, negative; or 5, very negative. In the large majority of cases, we believe that a firm's capital structure will be assessed as neutral. To assess a company's capital structure, we analyze four subfactors:

- Currency risk associated with debt,
- Debt maturity profile (or schedule),
- Interest rate risk associated with debt, and
- Investments.

138. Any of these subfactors can influence a firm's capital structure assessment, although some carry greater weight than others, based on a tiered approach:

- Tier one risk subfactors: Currency risk of debt and debt maturity profile, and
- Tier two risk subfactor: Interest rate risk of debt.

139. The initial capital structure assessment is based on the first three subfactors (see table 21). We may then adjust the preliminary assessment based on our assessment of the fourth subfactor, investments.

Table 21

Preliminary Capital Structure Assessment

Preliminary capital structure assessment	Subfactor assessments
Neutral	No tier one subfactor is negative.
Negative	One tier one subfactor is negative, and the tier two subfactor is neutral.
Very negative	Both tier one subfactors are negative, or one tier one subfactor is negative and the tier two subfactor is negative.

140. Tier one subfactors carry the greatest risks, in our view, and, thus, could have a significant impact on the capital structure assessment. This is because, in our opinion, these factors have a greater likelihood of affecting credit metrics and potentially causing liquidity and refinancing risk. The tier two subfactor is important in and of itself, but typically less so than the tier one subfactors. In our view, in the majority of cases, the tier two subfactor in isolation has a lower likelihood of leading to liquidity and default risk than do tier one subfactors.

141. The fourth subfactor, investments, as defined in paragraph 153, quantifies the impact of a company's investments on

its overall financial risk profile. Although not directly related to a firm's capital structure decisions, certain investments could provide a degree of asset protection and potential financial flexibility if they are monetized. Thus, the fourth subfactor could modify the preliminary capital structure assessment (see table 22). If the subfactor is assessed as neutral, then the preliminary capital structure assessment will stand. If investments is assessed as positive or very positive, we adjust the preliminary capital structure assessment upward (as per table 22) to arrive at the final assessment.

Table 22

Final Capital Structure Assessment

	--Investments subfactor assessment--		
Preliminary capital structure assessment	**Neutral**	**Positive**	**Very positive**
Neutral	Neutral	Positive	Very positive
Negative	Negative	Neutral	Positive
Very negative	Very negative	Negative	Negative

2. Capital structure analysis: Assessing the subfactors

a) Subfactor 1: Currency risk of debt

142. Currency risk arises when a company borrows without hedging in a currency other than the currency in which it generates revenues. Such an unhedged position makes the company potentially vulnerable to fluctuations in the exchange rate between the two currencies, in the absence of mitigating factors. We determine the materiality of any mismatch by identifying situations where adverse exchange-rate movements could weaken cash flow and/or leverage ratios. We do not include currency mismatches under the following scenarios:

- The country where a company generates its cash flows has its currency pegged to the currency in which the company has borrowed, or vice versa (or the currency of cash flows has a strong track record and government policy of stability with the currency of borrowings), examples being the Hong Kong dollar which is pegged to the U.S. dollar, and the Chinese renminbi which is managed in a narrow band to the U.S. dollar (and China's foreign currency reserves are mainly in U.S. dollars). Moreover, we expect such a scenario to continue for the foreseeable future;
- A company has the proven ability, through regulation or contract, to pass through changes in debt servicing costs to its customers; or
- A company has a natural hedge, such as where it may sell its product in a foreign currency and has matched its debt in that same currency.

143. We also recognize that even if an entity generates insufficient same-currency cash flow to meet foreign currency-denominated debt obligations, it could have substantial other currency cash flows it can convert to meet these obligations. Therefore, the relative amount of foreign denominated debt as a proportion of total debt is an important factor in our analysis. If foreign denominated debt, excluding fully hedged debt principal, is 15% or less of total debt, we assess the company as neutral on currency risk of debt. If foreign-denominated debt, excluding fully hedged debt principal, is greater than 15% of total debt, and debt to EBITDA is greater than 3.0x, we evaluate currency risks through further analysis.

144. If an entity's foreign-denominated debt in a particular currency represents more than 15% of total debt, and if its debt to EBITDA ratio is greater than 3.0x, we identify whether a currency-specific interest coverage ratio indicates potential

currency risk. The coverage ratio divides forecasted operating cash flow in each currency by interest payments over the coming 12 months for that same currency. It is often easier to ascertain the geographic breakdown of EBITDA as opposed to operating cash flow. So in situations where we don't have sufficient cash flow information, we may calculate an EBITDA to interest expense coverage ratio in the relevant currencies. If neither cash flow nor EBITDA information is disclosed, we estimate the relevant exposures based on available information.

145. In such an instance, our assessment of this subfactor is negative if we believe any appropriate interest coverage ratio will fall below 1.2x over the next 12 months.

b) Subfactor 2: Debt maturity profile

146. A firm's debt maturity profile shows when its debt needs to be repaid, or refinanced if possible, and helps determine the firm's refinancing risk. Lengthier and more evenly spread out debt maturity schedules reduce refinancing risk, compared with front-ended and compressed ones, since the former give an entity more time to manage business- or financial market-related setbacks.

147. In evaluating debt maturity profiles, we measure the weighted average maturity (WAM) of bank debt and debt securities (including hybrid debt) within a capital structure, and make simplifying assumptions that debt maturing beyond year five matures in year six. WAM = (Maturity1/Total Debt)*tenor1 + (Maturity2/Total Debt)* tenor2 +… (Thereafter/Total Debt)* tenor6

148. In evaluating refinancing risk, we consider risks in addition to those captured under the 12-month to 24-month time-horizons factored in our liquidity criteria (see "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013). While we recognize that investment-grade companies may have more certain future business prospects and greater access to capital than speculative-grade companies, all else being equal, we view a company with a shorter maturity schedule as having greater refinancing risk compared to a company with a longer one. In all cases, we assess a company's debt maturity profile in conjunction with its liquidity and potential funding availability. Thus, a short-dated maturity schedule alone is not a negative if we believe the company can maintain enough liquidity to pay off debt that comes due in the near term.

149. Our assessment of this subfactor is negative if the WAM is two years or less, and the amount of these near-term maturities is material in relation to the issuer's liquidity so that under our base-case forecast, we believe the company's liquidity assessment will become less than adequate or weak over the next two years due to these maturities. In certain cases, we may assess a debt maturity profile as negative regardless of whether or not the company passes the aforementioned test. We expect such instances to be rare, and will include scenarios where we believed a concentration of debt maturities within a five-year time horizon poses meaningful refinancing risk, either due to the size of the maturities in relation to the company's liquidity sources, the company's leverage profile, its operating trends, lender relationships, and/or credit market standings.

c) Subfactor 3: Interest rate risk of debt

150. The interest rate risk of debt subfactor analyzes the company's mix of fixed-rate and floating-rate debt. Generally, a higher proportion of fixed-rate debt leads to greater predictability and stability of interest expense and therefore cash flows. The exception would be companies whose operating cash flows are to some degree correlated with interest rate movements--for example, a regulated utility whose revenues are indexed to inflation--given the typical correlation

between nominal interest rates and inflation.

151. The mix of fixed versus floating-rate debt is usually not a significant risk factor for companies with intermediate or better financial profiles, strong profitability, and high interest coverage. In addition, the interest rate environment at a given point in time will play a role in determining the impact of interest rate movements. Our assessment of this subcategory will be negative if a 25% upward shift (e.g., from 2.0% to 2.5%) or a 100 basis-point upward shift (e.g., 2% to 3%) in the base interest rate of the floating rate debt will result in a breach of interest coverage covenants or interest coverage rating thresholds identified in the cash flow/leverage criteria (see section E.3).

152. Many loan agreements for speculative-grade companies contain a clause requiring a percentage of floating-rate debt to be hedged for a period of two to three years to mitigate this risk. However, in many cases the loan matures after the hedge expires, creating a mismatched hedge. We consider only loans with hedges that match the life of the loan to be--effectively--fixed-rate debt.

d) Subfactor 4: Investments

153. For the purposes of the criteria, investments refer to investments in unconsolidated equity affiliates, other assets where the realizable value isn't currently reflected in the cash flows generated from those assets (e.g. underutilized real-estate property), we do not expect any additional investment or support to be provided to the affiliate, and the investment is not included within Standard & Poor's consolidation scope and so is not incorporated in the company's business and financial risk profile analysis. If equity affiliate companies are consolidated, then the financial benefits and costs of these investments will be captured in our cash flow and leverage analysis. Similarly, where the company's ownership stake does not qualify for consolidation under accounting rules, we may choose to consolidate on a pro rata basis if we believe that the equity affiliates' operating and financing strategy is influenced by the rated entity. If equity investments are strategic and provide the company with a competitive advantage, or benefit a company's scale, scope, and diversity, these factors will be captured in our competitive position criteria and will not be used to assess the subfactor investments as positive. Within the capital structure criteria, we aim to assess nonstrategic financial investments that could provide a degree of asset protection and financial flexibility in the event they are monetized. These investments must be noncore and separable, meaning that a potential divestiture, in our view, has no impact on the company's existing operations.

154. In many instances, the cash flows generated by an equity affiliate, or the proportional share of the associate company's net income, might not accurately reflect the asset's value. This could occur if the equity affiliate is in high growth mode and is currently generating minimal cash flow or net losses. This could also be true of a physical asset, such as real estate. From a valuation standpoint, we recognize the subjective nature of this analysis and the potential for information gaps. As a result, in the absence of a market valuation or a market valuation of comparable companies in the case of minority interests in private entities, we will not ascribe value to these assets.

155. We assess this subfactor as positive or very positive if three key characteristics are met. First, an estimated value can be ascribed to these investments based on the presence of an existing market value for the firm or comparable firms in the same industry. Second, there is strong evidence that the investment can be monetized over an intermediate timeframe--in the case of an equity investment, our opinion of the marketability of the investment would be enhanced by the presence of an existing market value for the firm or comparable firms, as well as our view of market liquidity.

Third, monetization of the investment, assuming proceeds would be used to repay debt, would be material enough to positively move existing cash flow and leverage ratios by at least one category and our view on the company's financial policy, specifically related to financial discipline, supports the assessment that the potential proceeds would be used to pay down debt. This subfactor is assessed as positive if debt repayment from the investment sale has the potential to improve cash flow and leverage ratios by one category. We assess investments as very positive if proceeds upon sale of the investment have the potential to improve cash flow and leverage ratios by two or more categories. If the three characteristics are not met, this subfactor will be assessed as neutral and the preliminary capital structure assessment will stand.

156. We will not assess the investments subfactor as positive or very positive when the anchor is 'b+' or lower unless the three conditions described in paragraph 155 are met, and:

- For issuers with less than adequate or weak liquidity, the company has provided a credible near-term plan to sell the investment.
- For issuers with adequate or better liquidity, we believe that the company, if needed, could sell the investment in a relatively short timeframe.

H. Financial Policy

157. Financial policy refines the view of a company's risks beyond the conclusions arising from the standard assumptions in the cash flow/leverage assessment (see section E). Those assumptions do not always reflect or entirely capture the short-to-medium term event risks or the longer-term risks stemming from a company's financial policy. To the extent movements in one of these factors cannot be confidently predicted within our forward-looking evaluation, we capture that risk within our evaluation of financial policy. The cash flow/leverage assessment will typically factor in operating and cash flows metrics we observed during the past two years and the trends we expect to see for the coming two years based on operating assumptions and predictable financial policy elements, such as ordinary dividend payments or recurring acquisition spending. However, over that period and, generally, over a longer time horizon, the firm's financial policies can change its financial risk profile based on management's or, if applicable, the company's controlling shareholder's (see Appendix E, paragraphs 254-257) appetite for incremental risk or, conversely, plans to reduce leverage. We assess financial policy as 1) positive, 2) neutral, 3) negative, or as being owned by a financial sponsor. We further identify financial sponsor-owned companies as "FS-4", "FS-5", "FS-6", or "FS-6 (minus)" (see section H.2).

1. Assessing financial policy

158. First, we determine if a company is owned by a financial sponsor. Given the intrinsic characteristics and aggressive nature of financial sponsor's strategies (i.e. short- to intermediate-term holding periods and the use of debt or debt-like instruments to maximize shareholder returns), we assign a financial risk profile assessment to a firm controlled by a financial sponsor that reflects the likely impact on leverage due to these strategies and we do not separately analyze management's financial discipline or financial policy framework.

159. If a company is not controlled by a financial sponsor, we evaluate management's financial discipline and financial policy framework. Management's financial discipline measures its tolerance for incremental financial risk or,

conversely, its willingness to maintain the same degree of financial risk or to lower it compared with recent cash flow/leverage metrics and our projected ratios for the next two years. The company's financial policy framework assesses the comprehensiveness, transparency, and sustainability of the entity's financial policies. We do not assess these factors for financial sponsor controlled firms.

160. The financial discipline assessments can have a positive or negative influence on an enterprise's overall financial policy assessment, or can have no net effect. Conversely, the financial policy framework assessment cannot positively influence the overall financial policy assessment. It can constrain the overall financial policy assessment to no greater than neutral.

161. The separate assessments of a company's financial policy framework and financial discipline determine the financial policy adjustment.

162. We assess management's financial discipline as 1, positive; 2, neutral; or 3, negative. We determine the assessment by evaluating the predictability of an entity's expansion plans and shareholder return strategies. We take into account, generally, management's tolerance for material and unexpected negative changes in credit ratios or, instead, its plans to rapidly decrease leverage and keep credit ratios within stated boundaries.

163. A company's financial policy framework assessment is: 1, supportive or 2, non-supportive. We make the determination by assessing the comprehensiveness of a company's financial policy framework and whether financial targets are clearly communicated to a large number of stakeholders, and are well defined, achievable, and sustainable.

Table 23

Financial Policy Assessments

Assessment	What it means	Guidance
Positive	Indicates that we expect management's financial policy decisions to have a positive impact on credit ratios over the time horizon, beyond what can be reasonably built in our forecasts on the basis of normalized operating and cash flow assumptions. An example would be when a credible management team commits to dispose of assets or raise equity over the short to medium term in order to reduce leverage. A company with a 1 financial risk profile will not be assigned a positive assessment.	If financial discipline is positive, and the financial policy framework is supportive
Neutral	Indicates that, in our opinion, future credit ratios won't differ materially over the time horizon beyond what we have projected, based on our assessment of management's financial policy, recent track record, and operating forecasts for the company. A neutral financial policy assessment effectively reflects a low probability of "event risk," in our view.	If financial discipline is positive, and the financial policy framework is non-supportive. Or when financial discipline is neutral, regardless of the financial policy framework assessment.
Negative	Indicates our view of a lower degree of predictability in credit ratios, beyond what can be reasonably built in our forecasts, as a result of management's financial discipline (or lack of it). It points to high event risk that management's financial policy decisions may depress credit metrics over the time horizon, compared with what we have already built in our forecasts based on normalized operating and cash flow assumptions.	If financial discipline is negative, regardless of the financial policy framework assessment
Financial Sponsor*	We define a financial sponsor as an entity that follows an aggressive financial strategy in using debt and debt-like instruments to maximize shareholder returns. Typically, these sponsors dispose of assets within a short to intermediate time frame. Accordingly, the financial risk profile we assign to companies that are controlled by financial sponsors ordinarily reflects our presumption of some deterioration in credit quality in the medium term. Financial sponsors include private equity firms, but not infrastructure and asset-management funds, which maintain longer investment horizons.	We define financial sponsor-owned companies as companies that are owned 40% or more by a financial sponsor or a group of three or less financial sponsors and where we consider that the sponsor(s) exercise control of the company solely or together.

*Assessed as FS-4, FS-5, FS-6, or FS-6 (minus).

2. Financial sponsor-controlled companies

164. We define a financial sponsor as an entity that follows an aggressive financial strategy in using debt and debt-like instruments to maximize shareholder returns. Typically, these sponsors dispose of assets within a short-to-intermediate time frame. Financial sponsors include private equity firms, but not infrastructure and asset-management funds, which maintain longer investment horizons.

165. We define financial sponsor-owned companies as companies that are owned 40% or more by a financial sponsor or a group of three or less financial sponsors and where we consider that the sponsor(s) exercise control of the company solely or together.

166. We differentiate between financial sponsors and other types of controlling shareholders and companies that do not have controlling shareholders based on our belief that short-term ownership--such as exists in private equity sponsor-owned companies--generally entails financial policies aimed at achieving rapid returns for shareholders typically through aggressive debt leverage.

167. Financial sponsors often dictate policies regarding risk-taking, financial management, and corporate governance for the companies that they control. There is a common pattern of these investors extracting cash in ways that increase the companies' financial risk by utilizing debt or debt like instruments. Accordingly, the financial risk profile we assign to companies that are controlled by financial sponsors ordinarily reflect our presumption of some deterioration in credit quality or steadily high leverage in the medium term.

168. We assess the influence of financial sponsor ownership as "FS-4", "FS-5", "FS-6", and "FS-6 (minus)" depending on how aggressive we assume the sponsor will be and assign a financial risk profile accordingly (see table 24).

169. Generally, financial sponsor-owned issuers will receive an assessment of "FS-6" or "FS-6 (minus)", leading to a financial risk profile assessment of '6', under the criteria. A "FS-6" assessment indicates that, in our opinion, forecasted credit ratios in the medium term are likely be to be consistent with a '6' financial risk profile, based on our assessment of the financial sponsor's financial policy and track record. A "FS-6 (minus)" will likely be applied to companies that we forecast to have near-term credit ratios consistent with a '6' financial risk profile, but we believe the financial sponsor to be very aggressive and that leverage could increase materially even further from our forecasted levels.

170. In a small minority of cases, a financial sponsor-owned entity could receive an assessment of "FS-5". This assessment will apply only when we project that the company's leverage will be consistent with a '5' (aggressive) financial risk profile (see tables 17, 18, and 19), we perceive that the risk of releveraging is low based on the company's financial policy and our view of the owner's financial risk appetite, and liquidity is at least adequate.

171. In even rarer cases, we could assess the financial policy of a financial sponsor-owned entity as "FS-4". This assessment will apply only when all of the following conditions are met: other shareholders own a material (generally, at least 20%) stake, we expect the sponsor to relinquish control over the intermediate term, we project that leverage is currently consistent with a '4' (significant) financial risk profile (see tables 17, 18, and 19), the company has said it will maintain leverage at or below this level, and liquidity is at least adequate.

Table 24

Financial Risk Profile Implications For Sponsor-Owned Issuers

Assessment	What it Means	Guidance
FS-4	Financial risk profile set at '4'	Issuer must meet all of the following conditions: • Other shareholders must own a material (no less than 20%) stake; • We anticipate that the sponsor will relinquish control over the medium term; • For issuers subject to Table 17 (standard volatility), debt to EBITDA is less than 4x, and we estimate that it will remain less than 4x. For issuers that are subject to Table 18 (medial volatility), debt to EBITDA is below 4.5x and we forecast it to remain below that level. Or for issuers subject to Table 19 (low volatility), debt to EBITDA is less than 5x and our estimation is it will remain below that level; • The company has indicated a financial policy stipulating a level of leverage consistent with a significant or better financial risk profile (that is, debt to EBITDA of less than 4x when applying standard volatility tables, 4.5x when applying medial volatility tables, or less than 5x when applying low volatility tables) and • We assess liquidity to be at least adequate, with adequate covenant headroom.
FS-5	Financial risk profile set at '5'	Issuer must meet all of the following conditions: • For issuers subject to the standard volatility table, debt to EBITDA is less than 5x, and we estimate that it will remain less than 5x. For issuers that are subject to the medial volatility table, debt to EBITDA is below 5.5x and we forecast it to remain below that level. Or for issuers subject to the low volatility table, debt to EBITDA is less than 6x and our estimation is it will remain below that level; • We believe the risk of releveraging beyond 5x (standard volatility issuer), 5.5x (medial volatility issuer), or 6x (low volatility issuer) is low; and • We assess liquidity to be at least adequate, with adequate covenant headroom.
FS-6	Financial risk profile set at '6'	Standard & Poor's debt to EBITDA is greater than 5x (when applying the standard volatility table), greater than 5.5x (when applying the medial volatility table), or greater than 6x (when applying the low volatility table). However, we believe leverage is unlikely to increase meaningfully beyond these levels.
FS-6 (minus)	Financial risk profile set at '6', and anchor reduced by one notch (unless this results in a final rating below 'B-')	In determining the anchor the financial risk profile is a '6', but we believe the track record of the financial sponsor indicates that leverage could increase materially from already high levels.

3. Companies not controlled by a financial sponsor

172. For companies not controlled by a financial sponsor we evaluate management's financial discipline and financial policy framework to determine the influence on an entity's financial risk profile beyond what is implied by recent credit ratios and our cash flow and leverage forecasts. This influence can be positive, neutral, or negative.

173. We do not distinguish between management and a controlling shareholder that is not a financial sponsor when assessing these subfactors, as the controlling shareholder usually has the final say on financial policy.

a) Financial discipline

174. The financial discipline assessment is based on management's leverage tolerance and the likelihood of event risk. The criteria evaluate management's potential appetite to incur unforeseen, higher financial risk over a prolonged period and the associated impact on credit measures. We also assess management's capacity and commitment to rapidly decrease debt leverage to levels consistent with its credit ratio targets.

175. This assessment therefore seeks to determine whether unforeseen actions by management to increase, maintain, or reduce financial risk are likely to occur during the next two to three years, with either a negative or positive effect, or none at all, on our baseline forecasts for the period.

176. This assessment is based on the leverage tolerance of a company's management, as reflected in its plans or history of acquisitions, shareholder remuneration, and organic growth strategies (see Appendix E, paragraphs 258 to 263).

177. We assess financial discipline as positive, neutral, or negative, based on its potential impact on our forward-looking assessment of a firm's cash flow/leverage, as detailed in table 25. For example, a neutral assessment for leverage tolerance reflects our expectation that management's financial policy will unlikely lead to significant deviation from current and forecasted credit ratios. A negative assessment acknowledges a significant degree of event risk of increased leverage relative to our base-case forecast, resulting from the company's acquisition policy, its shareholder remuneration policy, or its organic growth strategy. A positive assessment indicates that the company is likely to take actions to reduce leverage, but we cannot confidently incorporate these actions into our baseline forward-looking assessment of cash flow/leverage.

178. A positive assessment indicates that management is committed and has the capacity to reduce debt leverage through the rapid implementation of credit enhancing measures, such as asset disposals, rights issues, or reductions in shareholder returns. In addition, management's track record over the past five years shows that it has taken actions to rapidly reduce unforeseen increases in debt leverage and that there have not been any prolonged periods when credit ratios were weaker than our expectations for the rating. Management, even if new, also has a track record of successful execution. Conversely, a negative assessment indicates management's financial policy allows for significant increase in leverage compared with both current levels and our forward-looking forecast under normal operating/financial conditions or does not have observable time limits or stated boundaries. Management has a track record of allowing for significant and prolonged peaks in leverage and there is no commitment or track record of management using mitigating measures to rapidly return to credit ratios consistent with our expectations.

179. As evidence of management's leverage tolerance, we evaluate its track record and plans regarding acquisitions, shareholder remuneration, and organic growth strategies (see Appendix E, paragraphs 258 to 263). Acquisitions could increase the risk that leverage will be higher than our base-case forecast if we view management's strategy as opportunistic or if its financial policy (if it exists) provides significant headroom for debt-financed acquisitions. Shareholder remuneration could also increase the risk of leverage being higher than our base-case forecast if management's shareholder reward policies are not particularly well defined or have no clear limits, management has a tolerance for shareholder returns exceeding operating cash flow, or has a track record of sustained cash returns despite weakening operating performance or credit ratios. Organic growth strategies can also result in leverage higher than our base-case forecast if these plans have no clear focus or investment philosophy, capital spending is fairly unpredictable,

or there is a track record of overspending or unexpected or rapid shifts in plans for new markets or products.

180. We also take into account management's track record and level of commitment to its stated financial policies, to the extent a company has a stated policy. Historical evidence and any deviations from stated policies are key elements in analyzing a company's leverage tolerance. Where material and unexpected deviation in leverage may occur (for example, on the back of operating weakness or acquisitions), we also assess management's plan to restore credit ratios to levels consistent with previous expectations through rapid and proactive non-organic measures. Management's track record to execute its deleveraging plan, its level of commitment, and the scope and timeframe of debt mitigating measures will be key differentiators in assessing a company's financial policy discipline.

Table 25

Assessing Financial Discipline

Descriptor	What it means	Guidance
Positive	Management is likely to take actions that result in leverage that is lower than our base-case forecast, but can't be confidently included in our base-case assumptions. Event risk is low.	Management is committed and has capacity to reduce debt leverage and increase financial headroom through the rapid implementation of credit enhancing measures, in line with its stated financial policy, if any. This relates primarily to management's careful and moderate policy with regard to acquisitions and shareholder remuneration as well as to its organic growth strategy. The assessments are supported by historical evidence over the past five years of not showing any prolonged weakening in the company's credit ratios, or relative to our base-case credit metrics' assumptions. Management, even if new, has a track record of successful execution.
Neutral	Leverage is not expected to deviate materially from our base-case forecast. Event risk is moderate.	Management's financial discipline with regard to acquisitions, shareholder remuneration, as well as its organic growth strategy does not result in significantly different leverage as defined in its stated financial policy framework.
Negative	Leverage could become materially higher than our base-case forecast. Event risk is high.	Management's financial policy framework does not explicitly rule out a significant increase in leverage compared to our base-case assumptions, possibly reflecting a greater event risk with regard to its M&A and shareholder remuneration policy as well as to its organic growth strategy. These points are supported by historical evidence over the past five years of allowing for significant and prolonged peaks in leverage, which remained unmitigated by credit supporting measures by management.

b) Financial policy framework

181. The company's financial policy framework assesses the comprehensiveness, transparency, and sustainability of the entity's financial policies (see Appendix E, paragraphs 264-268). This will help determine whether there is a satisfactory degree of visibility into the issuer's future financial risk profile. Companies that have developed and sustained a comprehensive set of financial policies are more likely to build long-term, sustainable credit quality than those that do not.

182. We will assess a company's financial policy framework as supportive or non-supportive based on evidence that supports the characteristics listed below. In order for an entity to receive a supportive assessment for financial policy framework, there must be sufficient evidence of management's financial policies to back that assessment.

183. A company assessed as supportive will generally exhibit the following characteristics:

- Management has a comprehensive set of financial policies covering key areas of financial risk, including debt leverage and liability management. Financial targets are well defined and quantifiable.
- Management's financial policies are clearly articulated in public forums (such as public listing disclosures and investor presentations) or are disclosed to a limited number of key stakeholders such as main creditors or to the credit rating agencies. The company's adherence to these policies is satisfactory.

- Management's articulated financial policies are considered achievable and sustainable. This assessment takes into consideration historical adherence to articulated policies, existing financial risk profile, capacity to sustain capital structure through nonorganic means, demands of key stakeholders, and the stability of financial policy parameters over time.

184. A company receives a non-supportive assessment if it does not meet all the conditions for a supportive assessment. We expect a non-supportive assessment to be uncommon.

I. Liquidity

185. Our assessment of liquidity focuses on monetary flows--the sources and uses of cash--that are the key indicators of a company's liquidity cushion. The analysis assesses the potential for a company to breach covenant tests related to declines in EBITDA, as well as its ability to absorb high-impact, low-probability events, the nature of the company's bank relationships, its standing in credit markets, and how prudent (or not) we believe its financial risk management to be (see "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013).

J. Management And Governance

186. The analysis of management and governance addresses how management's strategic competence, organizational effectiveness, risk management, and governance practices shape the issuer's competitiveness in the marketplace, the strength of its financial risk management, and the robustness of its governance. Stronger management of important strategic and financial risks may enhance creditworthiness (see "Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers," published Nov. 13, 2012).

K. Comparable Ratings Analysis

187. The comparable ratings analysis is our last step in determining a SACP on a company. This analysis can lead us to raise or lower our anchor, after adjusting for the modifiers, on a company by one notch based on our overall assessment of its credit characteristics for all subfactors considered in arriving at the SACP. This involves taking a holistic review of a company's stand-alone credit risk profile, in which we evaluate an issuer's credit characteristics in aggregate. A positive assessment leads to a one-notch upgrade, a negative assessment leads to a one-notch downgrade, and a neutral assessment indicates no change to the anchor.

188. The application of comparable ratings analysis reflects the need to "fine-tune" ratings outcomes, even after the use of each of the other modifiers. A positive or negative assessment is therefore likely to be common rather than exceptional.

189. We consider our assessments of each of the underlying subfactors to be points within a possible range. Consequently, each of these assessments that ultimately generate the SACP can be at the upper or lower end, or at the mid-point, of such a range:

- A company receives a positive assessment if we believe, in aggregate, its relative ranking across the subfactors typically to be at the higher end of the range;
- A company receives a negative assessment if we believe, in aggregate, its relative ranking across the subfactors typically to be at the lower end of the range;
- A company receives a neutral assessment if we believe, in aggregate, its relative ranking across the subfactors typically to be in line with the middle of the range.

190. The most direct application of the comparable ratings analysis is in the following circumstances:

- Business risk assessment. If we expect a company to sustain a position at the higher or lower end of the ranges for the business risk category assessment, the company could receive a positive or negative assessment, respectively.
- Financial risk assessment and financial metrics. If a company's actual and forecasted metrics are just above (or just below) the financial risk profile range, as indicated in its cash flow/leverage assessment, we could assign a positive or negative assessment.

191. We also consider additional factors not already covered, or existing factors not fully captured, in arriving at the SACP. Such factors will generally reflect less frequently observed credit characteristics, may be unique, or may reflect unpredictability or uncertain risk attributes, both positive and negative.

192. Some examples that we typically expect could lead to a positive or negative assessment using comparable ratings analysis include:

- Short operating track record. For newly formed companies or companies that have experienced transformational events, such as a significant acquisition, a lack of an established track record of operating and financial performance could lead to a negative assessment until such a track record is established.
- Entities in transition. A company in the midst of changes that we anticipate will strengthen or weaken its creditworthiness and that are not already fully captured elsewhere in the criteria could receive a positive or negative assessment. Such a transition could occur following major divestitures or acquisitions, or during a significant overhaul of its strategy, business, or financial structure.
- Industry or macroeconomic trends. When industry or macroeconomic trends indicate a strengthening or weakening of the company's financial condition that is not already fully captured elsewhere in the criteria, the company could receive a positive or negative assessment, respectively.
- Unusual funding structures. A company with exceptional financial resources that the criteria do not capture in the traditional ratio or liquidity analysis, or in capital structure analysis, could receive a positive assessment.
- Contingent risk exposures. How well (or not) a company identifies, manages, and reserves for contingent risk exposures that can arise if guarantees are called, derivative contract break clauses are activated, or substantial lawsuits are lost could lead to a negative assessment.

SUPERSEDED CRITERIA FOR ISSUERS WITHIN THE SCOPE OF THESE CRITERIA

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- How Stock Prices Can Affect An Issuer's Credit Rating, Sept. 26, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- Credit FAQ: Knowing The Investors In A Company's Debt And Equity, April 4, 2006

RELATED CRITERIA

- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Criteria: Ratios And Adjustments, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
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- Criteria Guidelines For Recovery Ratings On Global Industrial Issuers' Speculative-Grade Debt, Aug. 10, 2009
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

APPENDIXES

A. Country Risk

Table 26

Country And Regional Risk

Region
Western Europe
Southern Europe
Western + Southern Europe
East Europe
Central Europe
Eastern Europe and Central Asia
Middle East
Africa
North America
Central America
Latin America
The Caribbean
Asia-Pacific
Central Asia
East Asia
Australia NZ

Country	Region	GDP weighting (%)
South Africa	Africa	30.2
Egypt	Africa	28.0
Nigeria	Africa	23.5
Morocco	Africa	8.9

Table 26

Country And Regional Risk (cont.)		
Tunisia	Africa	5.4
Senegal	Africa	1.4
Mozambique	Africa	1.4
Zambia	Africa	1.2
Indonesia	Asia-Pacific	27.1
Taiwan	Asia-Pacific	20.1
Thailand	Asia-Pacific	14.4
Malaysia	Asia-Pacific	11.0
Philippines	Asia-Pacific	9.5
Vietnam	Asia-Pacific	7.1
Bangladesh	Asia-Pacific	6.8
Sri Lanka	Asia-Pacific	2.8
Laos	Asia-Pacific	0.4
Papua New Guinea	Asia-Pacific	0.4
Mongolia	Asia-Pacific	0.3
Australia	Australia NZ	88.2
New Zealand	Australia NZ	11.8
Guatemala	Central America	40.5
Costa Rica	Central America	30.2
Panama	Central America	29.3
India	Central Asia	86.5
Pakistan	Central Asia	9.3
Kazakhstan	Central Asia	4.2
Poland	Central Europe	46.3
Czech Republic	Central Europe	16.6
Hungary	Central Europe	11.3
Slovakia	Central Europe	7.7
Bulgaria	Central Europe	6.0
Croatia	Central Europe	4.6
Lithuania	Central Europe	3.8
Latvia	Central Europe	2.1
Estonia	Central Europe	1.6
China	East Asia	64.5
Japan	East Asia	23.6
Korea	East Asia	8.4
Hong Kong	East Asia	1.9
Singapore	East Asia	1.7
Greece	East Europe	77.5
Slovenia	East Europe	16.0
Cyprus	East Europe	6.5
Russia	Eastern Europe and Central Asia	80.4
Ukraine	Eastern Europe and Central Asia	10.8

Table 26

Country And Regional Risk (cont.)		
Belarus	Eastern Europe and Central Asia	4.8
Azerbaijan	Eastern Europe and Central Asia	3.2
Georgia	Eastern Europe and Central Asia	0.9
Brazil	Latin America	35.3
Mexico	Latin America	26.3
Argentina	Latin America	11.1
Colombia	Latin America	7.5
Venezuela	Latin America	6.0
Peru	Latin America	4.9
Chile	Latin America	4.8
Ecuador	Latin America	2.0
Uruguay	Latin America	0.8
El Salvador	Latin America	0.7
Paraguay	Latin America	0.6
Belize	Latin America	0.0
Turkey	Middle East	42.8
Saudi Arabia	Middle East	28.2
Israel	Middle East	9.4
Qatar	Middle East	7.2
Kuwait	Middle East	6.3
Oman	Middle East	3.4
Jordan	Middle East	1.5
Bahrain	Middle East	1.2
United States	North America	91.5
Canada	North America	8.5
Italy	Southern Europe	52.6
Spain	Southern Europe	40.4
Portugal	Southern Europe	7.0
Dominican Republic	The Caribbean	75.4
Jamaica	The Caribbean	19.2
Barbados	The Caribbean	5.4
Germany	Western Europe	28.7
United Kingdom	Western Europe	21.3
France	Western Europe	20.7
Netherlands	Western Europe	6.5
Belgium	Western Europe	3.9
Sweden	Western Europe	3.6
Switzerland	Western Europe	3.3
Austria	Western Europe	3.3
Norway	Western Europe	2.6
Denmark	Western Europe	1.9
Finland	Western Europe	1.8

Table 26

Country And Regional Risk (cont.)		
Ireland	Western Europe	1.8
Luxembourg	Western Europe	0.4
Iceland	Western Europe	0.1
Malta	Western Europe	0.1

B. Competitive Position

Table 27

List Of Industries, Subsectors, And Standard Competitive Position Group Profiles

Industry	Subsector	Competitive position group profile
Transportation cyclical	Airlines	Capital or asset focus
	Marine	Capital or asset focus
	Trucking	Capital or asset focus
Auto OEM	Automobile and truck manufacturers	Capital or asset focus
Metals and mining downstream	Aluminum	Commodity focus/cost driven
	Steel	Commodity focus/cost driven
Metals and mining upstream	Coal and consumable fuels	Commodity focus/cost driven
	Diversified metals and mining	Commodity focus/cost driven
	Gold	Commodity focus/cost driven
	Precious metals and minerals	Commodity focus/cost driven
Homebuilders and developers	Homebuilding	Capital or asset focus
Oil and gas refining and marketing	Oil and gas refining and marketing	Commodity focus/scale driven
Forest and paper products	Forest products	Commodity focus/cost driven
	Paper products	Commodity focus/cost driven
Building Materials	Construction materials	Capital or asset focus
Oil and gas integrated, exploration and production	Integrated oil and gas	Commodity focus/scale driven
	Oil and gas exploration and production	Commodity focus/scale driven
Agribusiness and commodity foods	Agricultural products	Commodity focus/scale driven
Real estate investment trusts (REITs)	Diversified REITs	Real-estate specific*
	Health care REITS	Real-estate specific*
	Industrial REITs	Real-estate specific*
	Office REITs	Real-estate specific*
	Residential REITs	Real-estate specific*
	Retail REITs	Real-estate specific*
	Specialized REITs	Not appplicable**
	Self-storage REITs	Real-estate specific*
	Net lease REITs	Real-estate specific*
	Real estate operating companies	Real-estate specific*
Leisure and sports	Casinos and gaming	Services and product focus
	Hotels, resorts, and cruise lines	Services and product focus

Table 27

List Of Industries, Subsectors, And Standard Competitive Position Group Profiles (cont.)		
	Leisure facilities	Services and product focus
Commodity chemicals	Commodity chemicals	Commodity focus/cost driven
	Diversified chemicals	Commodity focus/cost driven
	Fertilizers and agricultural chemicals	Commodity focus/cost driven
Auto suppliers	Auto parts and equipment	Capital or asset focus
	Tires and rubber	Capital or asset focus
	Vehicle-related suppliers	Capital or asset focus
Aerospace and defense	Aerospace and defense	Services and product focus
Technology hardware and semiconductors	Communications equipment	Capital or asset focus
	Computer hardware	Capital or asset focus
	Computer storage and peripherals	Capital or asset focus
	Consumer electronics	Capital or asset focus
	Electronic equipment and instruments	Capital or asset focus
	Electronic components	Capital or asset focus
	Electronic manufacturing services	Capital or asset focus
	Technology distributors	Capital or asset focus
	Office electronics	Capital or asset focus
	Semiconductor equipment	Capital or asset focus
	Semiconductors	Capital or asset focus
Specialty Chemicals	Industrial gases	Capital or asset focus
	Specialty chemicals	Capital or asset focus
Capital Goods	Electrical components and equipment	Capital or asset focus
	Heavy equipment and machinery	Capital or asset focus
	Industrial componentry and consumables	Capital or asset focus
	Construction equipment rental	Capital or asset focus
	Industrial distributors	Services and product focus
Engineering and construction	Construction and engineering	Services and product focus
Railroads and package express	Railroads	Capital or asset focus
	Package express	Services and product focus
	Logistics	Services and product focus
Business and consumer services	Consumer services	Services and product focus
	Distributors	Services and product focus
	Facilities services	Services and product focus
	General support services	Services and product focus
	Professional services	Services and product focus
Midstream energy	Oil and gas storage and transportation	Commodity focus/scale driven
Technology software and services	Internet software and services	Services and product focus
	IT consulting and other services	Services and product focus
	Data processing and outsourced services	Services and product focus
	Application software	Services and product focus
	Systems software	Services and product focus
	Consumer software	Services and product focus

Table 27

List Of Industries, Subsectors, And Standard Competitive Position Group Profiles (cont.)		
Consumer durables	Home furnishings	Services and product focus
	Household appliances	Services and product focus
	Housewares and specialties	Services and product focus
	Leisure products	Services and product focus
	Photographic products	Services and product focus
	Small appliances	Services and product focus
Containers and packaging	Metal and glass containers	Capital or asset focus
	Paper packaging	Capital or asset focus
Media and entertainment	Ad agencies and marketing services companies	Services and product focus
	Ad-supported internet content platforms	Services and product focus
	Broadcast TV networks	Services and product focus
	Cable TV networks	Services and product focus
	Consumer and trade magazines	Services and product focus
	Data/professional publishing	Services and product focus
	Directories	Services and product focus
	E-Commerce (services)	Services and product focus
	Educational publishing	Services and product focus
	Film and TV programming production	Capital or asset focus
	Miscellaneous media and entertainment	Services and product focus
	Motion picture exhibitors	Services and product focus
	Music publishing	Services and product focus
	Music recording	Services and product focus
	Newspapers	Services and product focus
	Outdoor advertising	Services and product focus
	Printing	Commodity focus/scale driven
	Radio broadcasters	Services and product focus
	Trade shows	Services and product focus
	TV stations	Services and product focus
Oil and gas drilling, equipment and services	Onshore contract drilling	Commodity focus/scale driven
	Offshore contract drilling	Capital or Asset Focus
	Oil and gas equipment and services (oilfield services)	Commodity focus/scale driven
Retail and restaurants	Catalog retail	Services and product focus
	Internet retail	Services and product focus
	Department stores	Services and product focus
	General merchandise stores	Services and product focus
	Apparel retail	Services and product focus
	Computer and electronics retail	Services and product focus
	Home improvement retail	Services and product focus
	Specialty stores	Services and product focus
	Automotive retail	Services and product focus
	Home furnishing retail	Services and product focus

Table 27

List Of Industries, Subsectors, And Standard Competitive Position Group Profiles (cont.)		
Health care services	Health care services	Commodity focus/scale driven
Transportation infrastructure	Airport services	National industries and utilities
	Highways	National industries and utilities
	Railtracks	National industries and utilities
	Marine ports and services	National industries and utilities
Environmental services	Environmental and facilities services	Services and product focus
Regulated utilities	Electric utilities	National industries and utilities
	Gas utilities	National industries and utilities
	Multi-utilities	National industries and utilities
	Water utilities	National industries and utilities
Unregulated power and gas	Independent power producers and energy traders	Capital or asset focus
	Merchant power	Capital or asset focus
Pharmaceuticals	Branded pharmaceuticals	Services and product focus
	Generic pharmaceuticals	Commodity focus/scale driven
Health care equipment	High-tech health care equipment	Product focus/scale driven
	Low-tech health care equipment	Commodity focus/scale driven
Branded nondurables	Brewers	Services and product focus
	Distillers and vintners	Services and product focus
	Soft drinks	Services and product focus
	Packaged foods and meats	Services and product focus
	Tobacco	Services and product focus
	Household products	Services and product focus
	Apparel, footwear, accessories, and luxury goods	Services and product focus
	Personal products	Services and product focus
Telecommunications and cable	Cable and satellite	Services and product focus
	Alternative carriers	Services and product focus
	Integrated telecommunication services	Services and product focus
	Wireless towers	Capital or asset focus
	Data center operators	Capital or asset focus
	Fiber-optic carriers	Capital or asset focus
	Wireless telecommunication services	Services and product focus

*See "Key Credit Factors For The Real Estate Industry," published Nov. 19, 2013. **For specialized REITs, there is no standard CPGP, as the CPGP will vary based on the underlying industry exposure (e.g. a forest and paper products REIT).

1. Analyzing subfactors for competitive advantage

193. Competitive advantage is the first component of our competitive position analysis. Companies that possess a sustainable competitive advantage are able to capitalize on key industry factors or mitigate associated risks more effectively. When a company operates in more than one business, we analyze each segment separately to form an overall view of its competitive advantage. In assessing competitive advantage, we evaluate the following subfactors:

- Strategy;
- Differentiation/uniqueness, product positioning/bundling;

- Brand reputation and marketing;
- Product/service quality;
- Barriers to entry, switching costs;
- Technological advantage and capabilities, technological displacement; and
- Asset profile.

a) Strategy

194. A company's business strategy will enhance or undermine its market entrenchment and business stability. Compelling business strategies can create a durable competitive advantage and thus a relatively stronger competitive position. We form an opinion as to the source and sustainability (if any) of the company's competitive advantage relative to its peers'. The company may have a differentiation advantage (i.e., brand, technology, regulatory) or a cost advantage (i.e., lower cost producer/servicer at the same quality level), or a combination.

195. Our assessment of a company's strategy is informed by a company's historical performance and how realistic we view its forward-looking business objectives to be. These may include targets for market shares, the percentage of revenues derived from new products, price versus the competition's, sales or profit growth, and required investment levels. We evaluate these objectives in the context of industry dynamics and the attractiveness of the markets in which the company participates.

b) Differentiation/uniqueness, product positioning/bundling

196. The attributes of product or service differentiation vary by sector, and may include product or services features, performance, durability, reliability, delivery, and comprehensiveness, among other measures. The intensity of competition may be lower where buyers perceive the product or service to be highly differentiated or to have few substitutes. Conversely, products and services that lack differentiation, or offer little value-added in the eyes of customers, are generally commodity-type products that primarily compete on price. Competition intensity will often be highest where limited or moderate investment (R&D, capital expenditures, or advertising) or low employee skill levels (for service businesses) are required to compete. Independent market surveys, media commentaries, market share trends, and evidence of leading or lagging when it comes to raising or lowering prices can indicate varying degrees of product differentiation.

197. Product positioning influences how companies are able to extend or protect market shares by offering popular products or services. A company's abilities to replace aging products with new ones, or to launch product extensions, are important elements of product positioning. In addition, the ability to sell multiple products or services to the same customer, known as bundling or cross-selling, (for instance, offering an aftermarket servicing contract together with the sale of a new appliance) can create a competitive advantage by increasing customers' switching costs and fostering loyalty.

c) Brand reputation and marketing

198. Brand equity measures the price premium a company receives based on its brand relative to the generic equivalent. High brand equity typically translates into customer loyalty, built partially via marketing campaigns. One measure of advertising effectiveness can be revenue growth compared with the increase in advertising expenses.

199. We also analyze re-investment and advertising strategies to anticipate potential strengthening or weakening of a

company's brand. A company's track record of boosting market share and delivering attractive margins could indicate its ability to build and maintain brand reputation.

d) Product/service level quality

200. The strength and consistency of a value proposition is an important factor contributing to a sustainable competitive advantage. Value proposition encompasses the key features of a product or a service that convince customers that their purchase has the right balance between price and quality. Customers generally perceive a product or a service to be good if their expectations are consistently met. Quality, both actual and perceived, can help a company attract and retain customers. Conversely, poor product and service quality may lead to product recalls, higher-than-normal product warnings, or service interruptions, which may reduce demand. Measures of customer satisfaction and retention, such as attrition rates and contract renewal rates, can help trace trends in product/service quality.

201. Maintaining the value proposition requires consistency and adaptability around product design, marketing, and quality-related operating controls. This is pertinent where product differentiation matters, as is the case in most noncommodity industries, and especially so where environmental or human health (concerns for the chemical, food, and pharmaceutical industries) adds a liability dimension to the quality and value proposition. Similarly, regulated utilities (which often do not set their own prices) typically focus on delivering uninterrupted service, often to meet the standards set by their regulator.

e) Barriers to entry, switching costs

202. Barriers to entry can reduce or eliminate the threat of new market entrants. Where they are effective, these barriers can lead to more predictable revenues and profits, by limiting pricing pressures and customer losses, lowering marketing costs, and improving operating efficiency. While barriers to entry may enable premium pricing, a dominant player may rationally choose pricing restraint to further discourage new entrants.

203. Barriers to entry can be one or more of: a natural or regulatory monopoly; supportive regulation; high transportation costs; an embedded customer base that would incur high switching costs; a proprietary product or service; capital or technological intensiveness.

204. A natural monopoly may result from unusually high requirements for capital and operating expenditures that make it uneconomic for a market to support more than a single, dominant provider. The ultimate barrier to entry is found among regulated utilities, which provide an essential service in their 'de juris' monopolies and receive a guaranteed rate of return on their investments. A supportive regulatory regime can include rules and regulations with high hurdles that discourage competitors, or mandate so many obligations for a new entrant as to make market entry financially unviable.

205. In certain industrial sectors, proprietary access to a limited supply of key raw materials or skilled labor, or zoning laws that effectively preclude a new entrant, can provide a strong barrier to entry. Factors such as relationships, long-term contracts or maintenance agreements, or exclusive distribution agreements can result in a high degree of customer stickiness. A proprietary product or service that's protected by a copyright or patent can pose a significant hurdle to new competitors.

f) Technological advantage and capabilities, technological displacement

206. A company may benefit from a proprietary technology that enables it to offer either a superior product or a commodity-type product at a materially lower cost. Proven research and development (R&D) capabilities can deliver a differentiated, superior product or service, as in the pharmaceutical or high tech sectors. However, optimal R&D strategies or the importance or effectiveness of patent protection differ by industry, stage of product development, and product lifecycle.

207. Technological displacement can be a threat in many industries; new technologies or extensions of current ones can effectively displace a significant portion of a company's products or services.

g) Asset profile

208. A company's asset profile is a reflection of its reinvestment, which creates tangible or intangible assets, or both. Companies in similar sectors and industries usually have similar reinvestment options and, thus, their asset profiles tend to be comparable. The reinvestment in "heavy" industries, such as oil and gas, metals and mining, and automotive, tends to produce more tangible assets, whereas the reinvestment in certain "light" industries, such as services, media and entertainment, and retail, tends to produce more intangible assets.

209. We evaluate how a company's asset profile supports or undermines its competitive advantage by reviewing its manufacturing or service creation capabilities and investment requirements, its distribution capabilities, and its track record and commitment to reinvesting in its asset base. This may include a review of the company's ability to attract and retain a talented workforce; its degree of vertical integration and how that may help or hinder its ability to secure supply sources, control the value-added part of its production chain, or adjust to technological developments; or its ability develop a broad and strong distribution network.

2. Analyzing subfactors for scale, scope, and diversity

210. In assessing the relative strength of this component, we evaluate four subfactors:

- Diversity of product or service range;
- Geographic diversity;
- Volumes, size of markets and revenues, and market shares; and
- Maturity of products or services.

211. In a given industry, entities with a broader mix of business activities are typically lower risk, and entities with a narrower mix are higher risk. High concentration of business volumes by product, customer, or geography, or a concentration in the production footprint or supplier base, can lead to less stable and predictable revenues and profits. Comparatively broader diversity helps a company withstand economic, competitive, or technological threats better than its peers.

212. There is no minimum size criterion, although size often provides a measure of diversification. Size and scope of operations is important relative to those of industry peers, though not in absolute terms. While relatively smaller companies can enjoy a high degree of diversification, they will likely be, almost by definition, more concentrated in terms of product, number of customers, or geography than their larger peers in the same industry.

213. Successful and continuing diversification supports a stronger competitive position. Conversely, poor diversification

weakens overall competitive position. For example, a company will weaken its overall business position if it enters new product lines and countries where it has limited expertise and lacks critical mass to be a real competitor to the incumbent market leaders. The weakness is greater when the new products or markets are riskier than the traditional core business.

214. Where applicable, we also include under scale, scope, and diversity an assessment of the potential benefits derived from unconsolidated (or partially consolidated) investments in strategic assets. The relative significance of such an investment and whether it is in an industry that exhibits high or, conversely, low correlation with the issuer's businesses would be considered in determining its potential benefits to scale, scope, and diversity. This excludes nonstrategic, financial investments, the analysis of which does not fall under the competitive position criteria but, instead, under the capital structure criteria.

a) Diversity of product or service range

215. The concentration of business volumes or revenues in a particular or comparatively small set of products or services can lead to less stable revenues and profits. Even if this concentration is in an attractive product or service, it may be a weakness. Likewise, the concentration of business volumes with a particular customer or a small group of customers, or the reliance on one or a few suppliers, can expose the company to a potentially greater risk of losing and having to replace related revenues and profits. On the other hand, successful diversification across products, customers, and/or suppliers can lead to more stable and predictable revenues and profits, which supports a stronger assessment of scale, scope, and diversity.

216. The relative contribution of different products or services to a company's revenues or profits helps us gauge its diversity. We also evaluate the correlation of demand between product or services lines. High correlation in demand between seemingly different product or service lines will accentuate volume declines during a weak part of the business cycle.

217. In most sectors, the share of revenue a company receives from its largest five to 10 customers or counterparties reveals how diversified its customer base is. However, other considerations such as the stability and credit quality of that customer base, and the company's ability to retain significant customers, can be mitigating or accentuating factors in our overall evaluation. Likewise, supplier dependency can often be measured based on a supplier's share of a company's operating or capital costs. However, other factors, such as the degree of interdependence between the company and its supplier(s), the substitutability of key supply sources, and the company's presumed ability to secure alternative supply without incurring substantial switching costs, are important considerations. Low switching costs (i.e. limited impact on input price, quality, or delivery times as a result of having to adapt to a new supply chain partner) can mitigate a high level of concentration.

b) Geographic diversity

218. We assess geographic diversity both from the standpoint of the breadth of the company's served or addressable markets, and from the standpoint of how geographically concentrated its facilities are.

219. The concentration of business volumes and revenues within a particular region can lead to greater exposure to economic factors affecting demand for a company's goods or services in that region. Even if the company's volumes and revenues are concentrated in an attractive region, it may still be vulnerable to a significant drop in demand for its

goods and services. Conversely, a company that serves multiple regions may benefit from different demand conditions in each, possibly resulting in greater revenue stability and more consistent profitability than a more focused peer's. That said, we consider geographic diversification in the context of the industry and the size of the local or regional economy. For instance, companies operating in local industries (such as food retailers) may benefit from a well-entrenched local position.

220. Generally, though, geographically concentrated production or service operations can expose a company to the risk of disruption, and damage revenues and profitability. Even when country risks don't appear significant, a company's vulnerability to exogenous factors (for example, natural disasters, labor or political unrest) increases with geographic concentration.

c) Volumes, size of markets and revenues, market share

221. Absolute sales or unit volumes and market share do not, by themselves, support a strong assessment of scale, scope, and diversity. Yet superior market share is a positive, since it may indicate a broad range of operations, products, or services.

222. We view volume stability (relative to peers') as a positive especially when: a company has demonstrated it during an economic downturn; if it has been achieved without relying on greater price concessions than competitors have made; and when it is likely to be sustained in the future. However, volume stability combined with shrinking market share could be evidence of a company's diminishing prospects for future profitability. We assess the predictability of business volumes and the likely degree of future volume stability by analyzing the company's performance relative to peers' on several industry factors: cyclicality; ability to adapt to technological and regulatory threats; the profile of the customer base (stickiness); and the potential life cycle of the company's products or services.

223. Depending on the industry sector, we measure a company's relative size and market share based on unit sales; the absolute amount of revenues; and the percentage of revenues captured from total industry revenues. We also adjust for industry and company specific qualitative considerations. For example, if an industry is particularly fragmented and has a number of similarly sized participants, none may have a particular advantage or disadvantage with respect to market share.

d) Maturity of products or services

224. The degree of maturity and the relative position on the lifecycle curve of the company's product or service portfolio affect the stability and sustainability of its revenues and margins. It is important to identify the stage of development of a company's products or services in order to measure the life cycle risks that may be associated with key products or services.

225. Mature products or services (e.g. consumer products or broadcast programming) are not necessarily a negative, in our view, if they still contribute reliable profits. If demand is declining for a company's product or service, we examine its track record on introducing new products with staying power. Similarly, a company's track record with product launches is particularly relevant.

3. Analyzing subfactors for operating efficiency

226. In assessing the relative strength of this component, we consider four subfactors:

- Cost structure,
- Manufacturing processes,
- Working capital management, and
- Technology.

227. To the extent a company has high operating efficiency, it should be able to generate better profit margins than peers that compete in the same markets, whatever the prevailing market conditions. The ability to minimize manufacturing and other operational costs and thus maximize margins and cash flow--for example, through manufacturing excellence, cost control, and diligent working capital management--will provide the funds for research and development, marketing, and customer service.

a) Cost structure

228. Companies that are well positioned from a cost standpoint will typically enjoy higher capacity utilization and be more profitable over the course of the business cycle. Cost structure and cost control are keys to generating strong profits and cash flow, particularly for companies that produce commodities, operate in mature industries, or face pricing pressures. It is important to consider whether a company or any of its competitors has a sustainable cost advantage, which can be based on access to cheaper energy, favorable manufacturing locations, or lower and more flexible labor costs, for example.

229. Where information is available, we examine a company's fixed versus variable cost mix as an indication of operating leverage, a measure of how revenue growth translates into growth in operating income. A company with significant operating leverage may witness dramatic declines in operating profit if unit volumes fall, as during cyclical downturns. Conversely, in an upturn, once revenues pass the breakeven point, a substantial percentage of incremental revenues typically becomes profit.

b) Manufacturing process

230. Capital intensity characterizes many heavy manufacturing sectors that require minimum volumes to produce acceptable profits, cash flow, and return on assets. We view capacity utilization through the business cycle (combined with the cost base) as a good indication of manufacturers' ability to maintain profits in varying economic scenarios. Our capacity utilization assessment is based on a company's production capacity across its manufacturing footprint. In addition, we consider the direction of a company's capacity utilization in light of our unit sales expectations, as opposed to analyzing it plant-by-plant.

231. Labor relations remain an important focus in our analysis of operating efficiency for manufacturers. Often, a company's labor cost structure is driven by its history of contractual negotiations and the countries in which it operates. We examine the rigidity or flexibility of a company's labor costs and the extent to which it relies on labor rather than automation. We analyze labor cost structure by assessing the extent of union representation, wage and benefit costs as a share of cost of goods sold (when available), and by assessing the balance of capital equipment vs. labor input in the manufacturing process. We also incorporate trends in a company's efforts to transfer labor costs from high-cost to low-cost regions.

c) Working capital management

232. Working capital management--of current or short-term assets and liabilities--is a key factor in our evaluation of operating efficiency. In general, companies with solid working capital management skills exhibit shorter cash conversion cycles (defined as days' investment in inventory and receivables less days' investment in accounts payable) than their lower-skilled peers. Short cash-conversion cycles could, for instance, demonstrate that a company has a stronger position in the supply chain (for example, requiring suppliers or dealers to hold more of its inventory). This allows a company to direct more capital than its peers can to other areas of investment.

d) Technology

233. Technology can play an important role in achieving superior operating efficiency through effective yield management (by improving input/output ratios), supply chain automation, and cost optimization.

234. Achieving high yield management is particularly important in industries with limited inventory and high fixed costs, such as transportation, lodging, media, and retail. The most efficient airlines can achieve higher revenue per available seat mile than their peers, while the most efficient lodging companies can achieve a higher revenue per available room than their peers. Both industries rely heavily on technology to effectively allocate inventory (seats and rooms) to maximize sales and profitability.

235. Effective supply chain automation systems enable companies to reduce investments in inventory and better forecast future orders based on current trends. By enabling electronic data interchange between supplier and retailer, such systems help speed orders and reorders for goods by quickly pinpointing which merchandise is selling well and needs restocking. They also identify slow moving inventory that needs to be marked down, making space available for fresh merchandise.

236. Effective use of technology can also help hold down costs by improving productivity via automation and workflow management. This can reduce selling, general, and administrative costs, which usually represent a substantial portion of expenditures for industries with high fixed costs, thus boosting earnings.

4. Industry-specific SER parameters

Table 28

SER Calibration By Industry Based On EBITDA

	--Volatility of profitability assessment*--					
	1	2	3	4	5	6
Transportation cyclical	=<10%	>10%-14%	>14%-22%	>22%-33%	>33%-76%	>76%
Auto OEM	=<25%	>25%-33%	>33%-35%	>35%-40%	>40%-46%	>46%
Metals and mining downstream	=<16%	>16%-31%	>31%-42%	>42%-53%	>53%-82%	>82%
Metals and mining upstream	=<16%	>16%-23%	>23%-28%	>28%-34%	>34%-59%	>59%
Homebuilders and developers	=<19%	>19%-33%	>33%-46%	>46%-65%	>65%-95%	>95%
Oil and gas refining and marketing	=<14%	>14%-21%	>21%-35%	>35%-46%	>46%-82%	>82%
Forest and paper products	=<9%	>9%-18%	>18%-26%	>26%-51%	>51%-114%	>114%
Building materials	=<9%	>9%-16%	>16%-19%	>19%-24%	>24%-33%	>33%
Oil and gas integrated, exploration and production	=<12%	>12%-19%	>19%-22%	>22%-28%	>28%-38%	>38%
Agribusiness and commodity foods	=<12%	>12%-19%	>19%-25%	>25%-39%	>39%-57%	>57%

Table 28

SER Calibration By Industry Based On EBITDA (cont.)

Real estate investment trusts (REITs)	=<5%	>5%-9%	>9%-13%	>13%-20%	>20%-32%	>32%
Leisure and sports	=<5%	>5%-9%	>9%-12%	>12%-16%	>16%-24%	>24%
Commodity chemicals	=<14%	>14%-19%	>19%-28%	>28%-37%	>37%-51%	>51%
Auto suppliers	=<15%	>15%-20%	>20%-26%	>26%-32%	>32%-45%	>45%
Aerospace and defense	=<6%	>6%-9%	>9%-15%	>15%-24%	>24%-41%	>41%
Technology hardware and semiconductors	=<11%	>11%-15%	>15%-22%	>22%-31%	>31%-58%	>58%
Specialty chemicals	=<5%	>5%-10%	>10%-14%	>14%-23%	>23%-36%	>36%
Capital goods	=<12%	>12%-16%	>16%-21%	>21%-30%	>30%-45%	>45%
Engineering and construction	=<9%	>9%-14%	>14%-20%	>20%-28%	>28%-39%	>39%
Railroads and package express	=<5%	>5%-8%	>8%-10%	>10%-13%	>13%-22%	>22%
Business and consumer services	=<4%	>4%-8%	>8%-11%	>11%-16%	>16%-30%	>30%
Midstream energy	=<5%	>5%-9%	>9%-11%	>11%-15%	>15%-31%	>31%
Technology software and services	=<4%	>4%-9%	>9%-14%	>14%-19%	>19%-33%	>33%
Consumer durables	=<7%	>7%-10%	>10%-13%	>13%-19%	>19%-35%	>35%
Containers and packaging	=<5%	>5%-7%	>7%-12%	>12%-18%	>18%-26%	>26%
Media and entertainment	=<6%	>6%-10%	>10%-14%	>14%-20%	>20%-29%	>29%
Oil and gas drilling, equipment and services	=<16%	>16%-22%	>22%-28%	>28%-44%	>44%-62%	>62%
Retail and restaurants	=<4%	>4%-8%	>8%-11%	>11%-16%	>16%-26%	>26%
Health care services	=<4%	>4%-5%	>5%-9%	>9%-12%	>12%-19%	>19%
Transportation infrastructure	=<2%	>2%-4%	>4%-7%	>7%-12%	>12%-19%	>19%
Environmental services	=<5%	>5%-9%	>9%-13%	>13%-22%	>22%-29%	>29%
Regulated utilities	=<4%	>4%-7%	>7%-9%	>9%-14%	>14%-26%	>26%
Unregulated power and gas	=<7%	>7%-16%	>16%-20%	>20%-29%	>29%-47%	>47%
Pharmaceuticals	=<5%	>5%-8%	>8%-11%	>11%-17%	>17%-32%	>32%
Health care equipment	=<3%	>3%-5%	>5%-6%	>6%-10%	>10%-25%	>25%
Branded nondurables	=<4%	>4%-7%	>7%-10%	>10%-15%	>15%-43%	>43%
Telecommunications and cable	=<3%	>3%-6%	>6%-9%	>9%-13%	>13%-23%	>23%
Overall	=<5%	>5%-9%	>9%-15%	>15%-23%	>23%-43%	>43%

*The data ranges include the values up to and including the upper bound. As an example, for a range of 5%-9%, a value of 5% is excluded, while a value of 9% is included; the numbers are rounded to the nearest whole number for presentation purposes.

Table 29

SER Calibration By Industry Based On EBITDA Margin

	--Volatility of profitability assessment*--					
	1	**2**	**3**	**4**	**5**	**6**
Transportation cyclical	=<4%	>4%-8%	>8%-16%	>16%-28%	>28%-69%	>69%
Auto OEM	=<15%	>15%-19%	>19%-29%	>29%-31%	>31%-45%	>45%
Metals and mining downstream	=<10%	>10%-18%	>18%-26%	>26%-36%	>36%-56%	>56%
Metals and mining upstream	=<8%	>8%-10%	>10%-14%	>14%-19%	>19%-31%	>31%
Homebuilders and developers	=<10%	>10%-18%	>18%-30%	>30%-56%	>56%-114%	>114%
Oil and gas refining and marketing	=<12%	>12%-22%	>22%-28%	>28%-42%	>42%-71%	>71%
Forest and paper products	=<8%	>8%-13%	>13%-21%	>21%-41%	>41%-117%	>117%
Building materials	=<4%	>4%-8%	>8%-13%	>13%-18%	>18%-23%	>23%

Table 29

SER Calibration By Industry Based On EBITDA Margin (cont.)

Oil and gas integrated, exploration and production	=<4%	>4%-6%	>6%-8%	>8%-13%	>13%-22%	>22%
Agribusiness and commodity foods	=<9%	>9%-14%	>14%-18%	>18%-27%	>27%-100%	>100%
Real estate investment trusts (REITs)	=<2%	>2%-5%	>5%-8%	>8%-13%	>13%-34%	>34%
Leisure and sports	=<3%	>3%-5%	>5%-6%	>6%-9%	>9%-18%	>18%
Commodity chemicals	=<9%	>9%-14%	>14%-18%	>18%-25%	>25%-37%	>37%
Auto suppliers	=<9%	>9%-13%	>13%-18%	>18%-23%	>23%-40%	>40%
Aerospace and defense	=<3%	>3%-6%	>6%-7%	>7%-12%	>12%-24%	>24%
Technology hardware and semiconductors	=<7%	>7%-10%	>10%-15%	>15%-21%	>21%-62%	>62%
Specialty chemicals	=<3%	>3%-6%	>6%-10%	>10%-19%	>19%-28%	>28%
Capital goods	=<6%	>6%-9%	>9%-13%	>13%-20%	>20%-33%	>33%
Engineering and construction	=<6%	>6%-8%	>8%-12%	>12%-17%	>17%-26%	>26%
Railroads and package express	=<2%	>2%-6%	>6%-8%	>8%-10%	>10%-17%	>17%
Business and consumer services	=<3%	>3%-5%	>5%-7%	>7%-12%	>12%-22%	>22%
Midstream energy	=<3%	>3%-6%	>6%-9%	>9%-14%	>14%-28%	>28%
Technology software and services	=<3%	>3%-6%	>6%-10%	>10%-15%	>15%-30%	>30%
Consumer durables	=<4%	>4%-8%	>8%-11%	>11%-15%	>15%-26%	>26%
Containers and packaging	=<5%	>5%-7%	>7%-9%	>9%-15%	>15%-22%	>22%
Media and entertainment	=<4%	>4%-6%	>6%-9%	>9%-14%	>14%-24%	>24%
Oil and gas drilling, equipment and services	=<6%	>6%-12%	>12%-16%	>16%-22%	>22%-32%	>32%
Retail and restaurants	=<3%	>3%-5%	>5%-7%	>7%-12%	>12%-21%	>21%
Health care services	=<3%	>3%-5%	>5%-6%	>6%-8%	>8%-15%	>15%
Transportation infrastructure	=<1%	>1%-3%	>3%-5%	>5%-7%	>7%-15%	>15%
Environmental services	=<3%	>3%-4%	>4%-6%	>6%-10%	>10%-24%	>24%
Regulated utilities	=<4%	>4%-7%	>7%-9%	>9%-14%	>14%-24%	>24%
Unregulated power and gas	=<6%	>6%-10%	>10%-15%	>15%-23%	>23%-41%	>41%
Pharmaceuticals	=<4%	>4%-5%	>5%-7%	>7%-10%	>10%-21%	>21%
Health care equipment	=<2%	>2%-4%	>4%-5%	>5%-10%	>10%-16%	>16%
Branded nondurables	=<3%	>3%-6%	>6%-9%	>9%-13%	>13%-28%	>28%
Telecommunications and cable	=<2%	>2%-4%	>4%-5%	>5%-7%	>7%-13%	>13%
Overall	=<3%	>3%-6%	>6%-10%	>10%-16%	>16%-32%	>32%

*The data ranges include the values up to and including the upper bound. As an example, for a range of 5%-9%, a value of 5% is excluded, while a value of 9% is included; the numbers are rounded to the nearest whole number for presentation purposes.

Table 30

SER Calibration By Industry Based On Return On Capital

	--Volatility of profitability assessment*--					
	1	**2**	**3**	**4**	**5**	**6**
Transportation cyclical	=<14%	>14%-28%	>28%-39%	>39%-53%	>53%-156%	>156%
Auto OEM	=<42%	>42%-64%	>64%-74%	>74%-86%	>86%-180%	>180%
Metals and mining downstream	=<25%	>25%-32%	>32%-43%	>43%-53%	>53%-92%	>92%
Metals and mining upstream	=<22%	>22%-30%	>30%-38%	>38%-45%	>45%-93%	>93%
Homebuilders and developers	=<12%	>12%-31%	>31%-50%	>50%-70%	>70%-88%	>88%

Table 30

SER Calibration By Industry Based On Return On Capital (cont.)

Oil and gas refining and marketing	=<14%	>14%-30%	>30%-48%	>48%-67%	>67%-136%	>136%
Forest and paper products	=<10%	>10%-22%	>22%-40%	>40%-89%	>89%-304%	>304%
Building materials	=<13%	>13%-20%	>20%-26%	>26%-36%	>36%-62%	>62%
Oil and gas integrated, exploration and production	=<16%	>16%-22%	>22%-31%	>31%-43%	>43%-89%	>89%
Agribusiness and commodity foods	=<12%	>12%-15%	>15%-29%	>29%-55%	>55%-111%	>111%
Real estate investment trusts (REITs)	=<8%	>8%-14%	>14%-20%	>20%-26%	>26%-116%	>116%
Leisure and sports	=<11%	>11%-17%	>17%-26%	>26%-34%	>34%-64%	>64%
Commodity chemicals	=<19%	>19%-28%	>28%-41%	>41%-50%	>50%-73%	>73%
Auto suppliers	=<20%	>20%-39%	>39%-50%	>50%-67%	>67%-111%	>111%
Aerospace and defense	=<7%	>7%-13%	>13%-19%	>19%-27%	>27%-61%	>61%
Technology hardware and semiconductors	=<8%	>8%-21%	>21%-34%	>34%-49%	>49%-113%	>113%
Specialty chemicals	=<5%	>5%-18%	>18%-28%	>28%-43%	>43%-64%	>64%
Capital goods	=<15%	>15%-24%	>24%-31%	>31%-45%	>45%-121%	>121%
Engineering and construction	=<12%	>12%-21%	>21%-23%	>23%-33%	>33%-54%	>54%
Railroads and package express	=<3%	>3%-11%	>11%-17%	>17%-20%	>20%-27%	>27%
Business and consumer services	=<9%	>9%-17%	>17%-23%	>23%-40%	>40%-87%	>87%
Midstream energy	=<5%	>5%-11%	>11%-17%	>17%-22%	>22%-34%	>34%
Technology software and services	=<8%	>8%-21%	>21%-35%	>35%-65%	>65%-105%	>105%
Consumer durables	=<8%	>8%-13%	>13%-20%	>20%-35%	>35%-60%	>60%
Containers and packaging	=<6%	>6%-14%	>14%-23%	>23%-35%	>35%-52%	>52%
Media and entertainment	=<9%	>9%-17%	>17%-26%	>26%-40%	>40%-86%	>86%
Oil and gas drilling, equipment and services	=<25%	>25%-33%	>33%-45%	>45%-65%	>65%-90%	>90%
Retail and restaurants	=<6%	>6%-14%	>14%-18%	>18%-26%	>26%-69%	>69%
Health care services	=<6%	>6%-10%	>10%-15%	>15%-25%	>25%-44%	>44%
Transportation infrastructure	=<5%	>5%-9%	>9%-12%	>12%-16%	>16%-27%	>27%
Environmental Services	=<7%	>7%-12%	>12%-24%	>24%-35%	>35%-72%	>72%
Regulated utilities	=<6%	>6%-9%	>9%-13%	>13%-20%	>20%-36%	>36%
Unregulated power and gas	=<14%	>14%-19%	>19%-29%	>29%-55%	>55%-117%	>117%
Pharmaceuticals	=<6%	>6%-8%	>8%-15%	>15%-20%	>20%-33%	>33%
Health care equipment	=<4%	>4%-8%	>8%-19%	>19%-31%	>31%-81%	>81%
Branded nondurables	=<6%	>6%-10%	>10%-17%	>17%-29%	>29%-63%	>63%
Telecommunications and cable	=<7%	>7%-13%	>13%-19%	>19%-26%	>26%-60%	>60%
Overall	=<7%	>7%-15%	>15%-23%	>23%-38%	>38%-81%	>81%

*The data ranges include the values up to and including the upper bound. As an example, for a range of 5%-9%, a value of 5% is excluded, while a value of 9% is included; the numbers are rounded to the nearest whole number for presentation purposes.

C. Cash Flow/Leverage Analysis

1. The merits and drawbacks of each cash flow measure

a) EBITDA

237. EBITDA is a widely used, and therefore a highly comparable, indicator of cash flow, although it has significant limitations. Because EBITDA derives from the income statement entries, it can be distorted by the same accounting issues that limit the use of earnings as a basis of cash flow. In addition, interest can be a substantial cash outflow for speculative-grade companies and therefore EBITDA can materially overstate cash flow in some cases. Nevertheless, it serves as a useful and common starting point for cash flow analysis and is useful in ranking the financial strength of different companies.

b) Funds from operations (FFO)

238. FFO is a hybrid cash flow measure that estimates a company's inherent ability to generate recurring cash flow from its operations independent of working capital fluctuations. FFO estimates the cash flow available to the company before working capital, capital spending, and discretionary items such as dividends, acquisitions, etc.

239. Because cash flow from operations tends to be more volatile than FFO, FFO is often used to smooth period-over-period variation in working capital. We consider it a better proxy of recurring cash flow generation because management can more easily manipulate working capital depending on its liquidity or accounting needs. However, we do not generally rely on FFO as a guiding cash flow measure in situations where assessing working capital changes is important to judge a company's cash flow generating ability and general creditworthiness. For example, for working-capital-intensive industries such as retailing, operating cash flow may be a better indicator than FFO of the firm's actual cash generation.

240. FFO is a good measure of cash flow for well-established companies whose long-term viability is relatively certain (i.e., for highly rated companies). For such companies, there can be greater analytical reliance on FFO and its relation to the total debt burden. FFO remains very helpful in the relative ranking of companies. In addition, more established, healthier companies usually have a wider array of financing possibilities to cover potential short-term liquidity needs and to refinance upcoming maturities. For marginal credit situations, the focus shifts more to free operating cash flow--after deducting the various fixed uses such as working capital investment and capital expenditures--as this measure is more directly related to current debt service capability.

c) Cash flow from operations (CFO)

241. The measurement and analysis of CFO forms an important part of our ratings assessment, in particular for companies that operate in working-capital-intensive industries or industries in which working capital flows can be volatile. CFO is distinct from FFO as it is a pure measure of cash flow calculated after accounting for the impact on earnings of changes in operating assets and liabilities. CFO is cash flow that is available to finance items such as capital expenditures, repay borrowing, and pay for dividends and share buybacks.

242. In many industries, companies shift their focus to cash flow generation in a downturn. As a result, even though they typically generate less cash from ordinary business activities because of low capacity utilization and relatively low fixed-cost absorption, they may generate cash by reducing inventories and receivables. Therefore, although FFO is likely to be lower in a downturn, the impact on CFO may not be as great. In times of strong growth the opposite will be true, and consistently lower CFO compared to FFO without a corresponding increase in revenue and profitability can indicate an untenable situation.

243. Working capital is a key element of a company's cash flow generation. While there tends to be a need to build up working capital and therefore to consume cash in a growth or expansion phase, changes in working capital can also act as a buffer in case of a downturn. Many companies will sell off inventories and invest a lower amount in raw materials because of weaker business activities, both of which reduce the amount of capital and cash that is tied up in working capital. Therefore, working capital fluctuations can occur both in periods of revenue growth and contraction and analyzing a company's near-term working capital needs is crucial for estimating future cash flow developments.

244. Often, businesses that are capital intensive are not working-capital-intensive: most of the capital commitment is upfront in equipment and machinery, while asset-light businesses may have to invest proportionally more in inventories and receivables. That also affects margins, because capital-intensive businesses tend to have proportionally lower operating expenses (and therefore higher EBITDA margins), while working-capital-intensive businesses usually report lower EBITDA margins. The resulting cash flow volatility can be significant: because all investment is made upfront in a capital-intensive business, there is usually more room to absorb subsequent EBITDA volatility because margins are higher. For example, a capital-intensive company may remain reasonably profitable even if its EBITDA margin declines from 30% to 20%. By contrast, a working-capital-intensive business with a lower EBITDA margin (due to higher operating expenses) of 8% can post a negative EBITDA margin if EBITDA volatility is large.

d) Free operating cash flow (FOCF)

245. By deducting capital expenditures from CFO, we arrive at FOCF, which can be used as a proxy for a company's cash generated from core operations. We may exclude discretionary capital expenditures for capacity growth from the FOCF calculation, but in practice it is often difficult to discriminate between spending for expansion and replacement. And, while companies have some flexibility to manage their capital budgets to weather down cycles, such flexibility is generally temporary and unsustainable in light of intrinsic requirements of the business. For example, companies can be compelled to increase their investment programs because of strong demand growth or technological changes. Regulated entities (for example, telecommunications companies) might also face significant investment requirements related to their concession contracts (the understanding between a company and the host government that specifies the rules under which the company can operate locally).

246. Positive FOCF is a sign of strength and helpful in distinguishing between two companies with the same FFO. In addition, FOCF is helpful in differentiating between the cash flows generated by more and less capital-intensive companies and industries.

247. In highly capital-intensive industries (where maintenance capital expenditure requirements tend to be high) or in other situations in which companies have little flexibility to postpone capital expenditures, measures such as FFO to debt and debt to EBITDA may provide less valuable insight into relative creditworthiness because they fail to capture potentially meaningful capital expenditures. In such cases, a ratio such as FOCF to debt provides greater analytical insight.

248. A company serving a low-growth or declining market may exhibit relatively strong FOCF because of diminishing fixed and working capital needs. Growth companies, in contrast, exhibit thin or even negative FOCF because of the investment needed to support growth. For the low-growth company, credit analysis weighs the positive, strong current cash flow against the danger that this high level of cash flow might not be sustainable. For the high-growth company,

the opposite is true: weighing the negatives of a current cash deficit against prospects of enhanced cash flow once current investments begin yielding cash benefits. In the latter case, if we view the growth investment as temporary and not likely to lead to increased leverage over the long-term, we'll place greater analytical importance on FFO to debt rather than on FOCF to debt. In any event, we also consider the impact of a company's growth environment in our business risk analysis, specifically in a company's industry risk analysis (see section B).

e) Discretionary cash flow (DCF)

249. For corporate issuers primarily rated in the investment-grade universe, DCF to debt can be an important barometer of future cash flow adequacy as it more fully reflects a company's financial policy, including decisions regarding dividend payouts. In addition, share buybacks and potential M&A, both of which can represent very significant uses of cash, are important components in cash flow analysis.

250. The level of dividends depends on a company's financial strategy. Companies with aggressive dividend payout targets might be reluctant to reduce dividends even under some liquidity pressure. In addition, investment-grade companies are less likely to reduce dividend payments following some reversals--although dividends ultimately are discretionary. DCF is the truest reflection of excess cash flow, but it is also the most affected by management decisions and, therefore, does not necessarily reflect the potential cash flow available.

D. Diversification/Portfolio Effect

1. Academic research

251. Academic research recently concluded that, during the global financial crisis of 2007-2009, conglomerates had the advantage over single sector-focused firms because they had better access to the credit markets as a result of their debt co-insurance and used the internal capital markets more efficiently (i.e., their core businesses had stronger cash flows). Debt co-insurance is the view that the joining-together of two or more firms whose earnings streams are less-than-perfectly correlated reduces the risk of default of the merged firms (i.e., the co-insurance effect) and thereby increases the "debt capacity" or "borrowing ability" of the combined enterprise. These financing alternatives became more valuable during the crisis. (Source: "Does Diversification Create Value In The Presence Of External Financing Constraints? Evidence From The 2007-2009 Financial Crisis," Venkat Kuppuswamy and Belen Villalonga, Harvard Business School, Aug. 19, 2011.)

252. In addition, fully diversified, focused companies saw more narrow credit default swap spreads from 2004-2010 vs. less diversified firms. This highlighted that lenders were differentiating for risk and providing these companies with easier and cheaper access to capital. (Source: "The Power of Diversified Companies During Crises," The Boston Consulting Group and Leipzig Graduate School of Management, January 2012.)

253. Many rated conglomerates are either country- or region-specific; only a small percentage are truly global. The difference is important when assessing the country and macroeconomic risk factors. Historical measures for each region, based on volatility and correlation, reflect regional trends that are likely to change over time.

E. Financial Policy

1. Controlling shareholders

254. Controlling shareholder(s)--if they exist--exert significant influence over a company's financial risk profile, given their ability to use their direct or indirect control of the company's financial policies for their own benefit. Although the criteria do not associate the presence of controlling shareholder(s) to any predefined negative or positive impact, we assess the potential medium- to long-term implications for a company's credit standing of these strategies. Long-term ownership--such as exists in many family-run businesses--is often accompanied by financial discipline and reluctance to incur aggressive leverage. Conversely, short-term ownership--such as exists in private equity sponsor-owned companies--generally entails financial policies aimed at achieving rapid returns for shareholders typically through aggressive debt leverage.

255. The criteria define controlling shareholder(s) as:

- A private shareholder (an individual or a family) with majority ownership or control of the board of directors;
- A group of shareholders holding joint control over the company's board of directors through a shareholder agreement. The shareholder agreement may be comprehensive in scope or limited only to certain financial aspects; and
- A private equity firm or a group of private equity firms holding at least 40% in a company or with majority control of its board of directors.

256. A company is not considered to have a controlling shareholder if it is publicly listed with more than 50% of voting interest listed or when there is no evidence of a particular shareholder or group of shareholders exerting 'de facto' control over a company.

257. Companies that have as their controlling shareholder governments or government-related entities, infrastructure and asset-management funds, and diversified holding companies and conglomerates are assessed in separate criteria.

2. Financial discipline

a) Leverage influence from acquisitions

258. Companies may employ more or less acquisitive growth strategies based on industry dynamics, regulatory changes, market opportunities, and other factors. We consider management teams with disciplined, transparent acquisition strategies that are consistent with their financial policy framework as providing a high degree of visibility into the projected evolution of cash flow and credit measures. Our assessment takes into account management's track record in terms of acquisition strategy and the related impact on the company's financial risk profile. Historical evidence of limited management tolerance for significant debt-funded acquisitions provides meaningful support for the view that projected credit ratios would not significantly weaken as a result of the company's acquisition policy. Conversely, management teams that pursue opportunistic acquisition strategies, without well-defined parameters, increase the risks that the company's financial risk profile may deteriorate well beyond our forecasts.

259. Acquisition funding policies and management's track record in this respect also provide meaningful insight in terms of credit ratio stability. In the criteria, we take into account management's willingness and capacity to mobilize all funding resources to restore credit quality, such as issuing equity or disposing of assets, to mitigate the impact of sizable

acquisitions on credit ratios. The financial policy framework and related historical evidence are key considerations in our assessment.

b) Leverage influence from shareholder remuneration policies

260. A company's approach to rewarding shareholders demonstrates how it balances the interests of its various stakeholders over time. Companies that are consistent and transparent in their shareholder remuneration policies, and exhibit a willingness to adjust shareholder returns to mitigate adverse operating conditions, provide greater support to their long-term credit quality than other companies. Conversely, companies that prioritize cash returns to shareholders in periods of deteriorating economic, operating, or share price performance can significantly undermine long-term credit quality and exacerbate the credit impact of adverse business conditions. In assessing a company's shareholder remuneration policies, the criteria focus on the predictability of shareholder remuneration plans, including how a company builds shareholder expectations, its track record in executing shareholder return policies over time, and how shareholder returns compare with industry peers'.

261. Shareholder remuneration policies that lack transparency or deviate meaningfully from those of industry peers introduce a higher degree of event risk and volatility and will be assessed as less predictable under the criteria. Dividend and capital return policies that function primarily as a means to distribute surplus capital to shareholders based on transparent and stable payout ratios--after satisfying all capital requirements and leverage objectives of the company, and that support stable to improving leverage ratios--are considered the most supportive of long term credit quality.

c) Leverage influence from plans regarding investment decisions or organic growth strategies

262. The process by which a company identifies, funds, and executes organic growth, such as expansion into new products and/or new markets, can have a significant impact on its long-term credit quality. Companies that have a disciplined, coherent, and manageable organic growth strategy, and have a track record of successful execution are better positioned to continue to attract third-party capital and maintain long-term credit quality. By contrast, companies that allocate significant amounts of capital to numerous, unrelated, large and/or complex projects and often incur material overspending against the original budget can significantly increase their credit risk.

263. The criteria assess whether management's organic growth strategies are transparent, comprehensive, and measurable. We seek to evaluate the company's mid- to long-term growth objectives--including strategic rationales and associated execution risks--as well as the criteria it uses to allocate capital. Effective capital allocation is likely to include guidelines for capital deployment, including minimum return hurdles, competitor activity analysis, and demand forecasting. The company's track record will provide key data for this assessment, including how well it executes large and/or complex projects against initial budgets, cost overruns, and timelines.

3. Financial policy framework

a) Comprehensiveness of financial policy framework

264. Financial policies that are clearly defined, unambiguous, and provide a tight framework around management behavior are the most reliable in determining an issuer's future financial risk profile. We assess as consistent with a supportive assessment, policies that are clear, measurable, and well understood by all key stakeholders. Accordingly, the financial policy framework must include well-defined parameters regarding how the issuer will manage its cash flow protection

strategies and debt leverage profile. This includes at least one key or a combination of financial ratio constraints (such as maximum debt to EBITDA threshold) and the latter must be relevant with respect to the issuer's industry and/or capital structure characteristics.

265. By contrast, the absence of established financial policies, policies that are vague or not quantifiable, or historical evidence of significant and unexpected variation in management's long-term financial targets could contribute to an overall assessment of a non-supportive financial policy framework.

b) Transparency of financial policies

266. We assess as supportive financial policy objectives that are transparent and well understood by all key stakeholders and we view them as likely to influence an issuer's financial risk profile over time. Alternatively, financial policies, if they exist, that are not communicated to key stakeholders and/or where there is limited historical evidence to support the company's commitment to these policies, are non-supportive, in our view. We consider the variety of ways in which a company communicates its financial policy objectives, including public disclosures, investor presentation materials, and public commentary.

267. In some cases, however, a company may articulate its financial policy objectives to a limited number of key stakeholders, such as its main creditors or to credit rating agencies. In these situations, a company may still receive a supportive classification if we assess that there is a sufficient track record (more than three years) to demonstrate a commitment to its financial policy objectives.

c) Achievability and sustainability of financial policies

268. To assess the achievability and sustainability of a company's financial policies, we consider a variety of factors, including the entity's current and historical financial risk profile; the demands of its key stakeholders (including dividend and capital return expectations of equity holders); and the stability of the company's financial policies that we have observed over time. If there is evidence that the company is willing to alter its financial policy framework because of adverse business conditions or growth opportunities (including M&A), this could support an overall assessment of non-supportive.

4. Financial policy adjustments--examples

269. Example 1: A moderately leveraged company has just been sold to a new financial sponsor. The financial sponsor has not leveraged the company yet and there is no stated financial policy at the outset. We expect debt leverage to increase upon refinancing, but we are not able to factor it precisely in our forecasts yet.
Likely outcome: FS-6 financial policy assessment, implying that we expect the new owner to implement an aggressive financial policy in the absence of any other evidence.

270. Example 2: A company has two owners--a family owns 75%, a strategic owner holds the remaining 25%. Although the company has provided Standard & Poor's with some guidance on long-term financial objectives, the overall financial policy framework is not sufficiently structured nor disclosed to a sufficient number of stakeholders to qualify for a supportive assessment. Recent history, however, does not provide any evidence of unexpected, aggressive financial transactions and we believe event risk is moderate.
Likely outcome: Neutral financial policy impact, including an assessment of neutral for financial discipline. Although the company's financial framework does not support long-term visibility, historical evidence and stability of management suggest that event risk is not significant. The unsupportive financial framework assessment, however,

prevents the company from qualifying for an overall positive financial policy assessment, should the conditions for positive financial discipline be met.

271. Example 3: A company (not owned by financial sponsors) has stated leverage targets equivalent to a significant financial risk profile assessment. The company continues to make debt-financed acquisitions yet remains within its leverage targets, albeit at the weaker end of these. Our forecasts are essentially built on expectations that excess cash flow will be fully used to fund M&A or, possibly pay share repurchases, but that management will overall remain within its leverage targets.
Likely outcome: Neutral financial policy impact. Although management is fairly aggressive, the company consistently stays within its financial policy targets. We think our forecasts provide a realistic view of the evolution of the company's credit metrics over the next two years. No event risk adjustment is needed.

272. Example 4: A company (not owned by a financial sponsor) has just made a sizable acquisition (consistent with its long-term business strategy) that has brought its credit ratios out of line. Management expressed its commitment to rapidly improve credit ratios back to its long-term ratio targets-–representing an acceptable range for the SACP--through asset disposals or a rights issue. We see their disposal plan (or rights issue) as realistic but precise value and timing are uncertain. At the same time, management has a supportive financial policy framework, a positive track record of five years, and assets are viewed as fairly easily tradable.
Likely outcome: Positive financial policy impact. Although forecast credit ratios will remain temporarily depressed, as we cannot fully factor in asset disposals (or rights issue) due to uncertainty on timing/value, or without leaking confidential information, the company's credit risk should benefit from management's positive track record and a supportive financial policy framework. The anchor will be better by one notch if management and governance is at least satisfactory and liquidity is at least adequate.

273. Example 5: A company (not owned by a financial sponsor) has very solid financial ratios, providing it with meaningful flexibility for M&A when compared with management's long-term stated financial policy. Also, its stock price performance is somewhat below that of its closest industry peers. Although we have no recent evidence of any aggressive financial policy steps, we fundamentally believe that, over the long-term term, the company will end up using its financial flexibility for the right M&A opportunity, or alternatively return cash to shareholders.
Likely outcome: Negative financial policy impact. Long-term event risk derived from M&A cannot be built into forecasts nor shareholder returns (share buybacks or one-off dividends) be built into forecasts to attempt aligning projected ratios with stated long-term financial policy levels. This is because our forecasts are based on realistic and reasonably predictable assumptions for the medium term. The anchor will be adjusted down, by one notch or more, because of the negative financial policy assessment.

F. Corporate Criteria Glossary

Anchor: The combination of an issuer's business risk profile assessment and its financial risk profile assessment determine the anchor. Additional rating factors can then modify the anchor to determine the final rating or SACP.

Asset profile: A descriptive way to look at the types and quality of assets that comprise a company (examples can include tangible versus intangible assets, those assets that require large and continuing maintenance, upkeep, or reinvestment, etc.).

Business risk profile: This measure comprises the risk and return potential for a company in the market in which it participates, the country risks within those markets, the competitive climate, and the competitive advantages and disadvantages the company has. The criteria combine the assessments for Corporate Industry and Country Risk Assessment (CICRA), and competitive position to determine a company's business risk profile assessment.

Capital-intensive company: A company exhibiting large ongoing capital spending to sales, or a large amount of depreciation to sales. Examples of capital-intensive sectors include oil production and refining, telecommunications, and transportation sectors such as railways and airlines.

Cash available for debt repayment: Forecast cash available for debt repayment is defined as the net change in cash for the period before debt borrowings and debt repayments. This includes forecast discretionary cash flow adjusted for our expectations of: share buybacks, net of any share issuance, and M&A. Discretionary cash flow is defined as cash flow from operating activities less capital expenditures and total dividends.

Competitive position: Our assessment of a company's: 1) competitive advantage; 2) operating efficiency; 3) scale, scope, and diversity; and 4) profitability.

- Competitive advantage--The strategic positioning and attractiveness to customers of the company's products or services, and the fragility or sustainability of its business model.
- Operating efficiency--The quality and flexibility of the company's asset base and its cost management and structure.
- Scale, scope, and diversity--The concentration or diversification of business activities.
- Profitability--Our assessment of both the company's level of profitability and volatility of profitability.

Competitive Position Group Profile (CPGP): Used to determine the weights to be assigned to the three components of competitive position other than profitability. While industries are assigned to one of the six profiles, individual companies and industry subsectors can be classified into another CPGP because of unique characteristics. Similarly, national industry risk factors can affect the weighing. The six CPGPs are:

- Services and product focus,
- Product focus/scale driven,
- Capital or asset focus,
- Commodity focus/cost driven,
- Commodity focus/scale driven, and
- National industry and utilities.

Conglomerate: Companies that have at least three distinct business segments, each contributing between 10%-50% of EBITDA or FOCF. Such companies may benefit from the diversification/portfolio effect.

Controlling shareholders: Equity owners who are able to affect decisions of varying effect on operations, leverage, and shareholder reward without necessarily being a majority of shareholders.

Corporate Industry and Country Risk Assessment (CICRA): The result of the combination of an issuer's country risk assessment and industry risk assessment.

Debt co-insurance: The view that the joining-together of two or more firms whose earnings streams are less-than-perfectly correlated reduces the risk of default of the merged firms (i.e., the co-insurance effect) and thereby increases the "debt capacity" or "borrowing ability" of the combined enterprise. These financing alternatives became more valuable during the global financial crisis of 2007-2009.

Financial headroom: Measure of deviation tolerated in financial metrics without moving outside or above a pre-designated band or limit typically found in loan covenants (as in a debt to EBITDA multiple that places a constraint on leverage). Significant headroom would allow for larger deviations.

Financial risk profile: The outcome of decisions that management makes in the context of its business risk profile and its financial risk tolerances. This includes decisions about the manner in which management seeks funding for the company and how it constructs its balance sheet. It also reflects the relationship of the cash flows the organization can achieve, given its business risk profile, to its financial obligations. The criteria use cash flow/leverage analysis to determine a corporate issuer's financial risk profile assessment.

Financial sponsor: An entity that follows an aggressive financial strategy in using debt and debt-like instruments to maximize shareholder returns. Typically, these sponsors dispose of assets within a short to intermediate time frame. Financial sponsors include private equity firms, but not infrastructure and asset-management funds, which maintain longer investment horizons.

Profitability ratio: Commonly measured using return on capital and EBITDA margins but can be measured using sector-specific ratios. Generally calculated based on a five-year average, consisting of two years of historical data, and our projections for the current year and the next two financial years.

Shareholder remuneration policies: Management's stated shareholder reward plans (such as a buyback or dividend amount, or targeted payout ratios).

Stand-alone credit profile (SACP): Standard & Poor's opinion of an issue's or issuer's creditworthiness, in the absence of extraordinary intervention or support from its parent, affiliate, or related government or from a third-party entity such as an insurer.

Transfer and convertibility assessment: Standard & Poor's view of the likelihood of a sovereign restricting nonsovereign access to foreign exchange needed to satisfy the nonsovereign's debt service obligations.

Unconsolidated equity affiliates: Companies in which an issuer has an investment, but which are not consolidated in an issuer's financial statements. Therefore, the earnings and cash flows of the investees are not included in our primary metrics unless dividends are received from the investees.

Upstream/midstream/downstream: Referring to exploration and production, transport and storage, and refining and distributing, respectively, of natural resources and commodities (such as metals, oil, gas, etc.).

Volatility of profitability/SER: We base the volatility of profitability on the standard error of the regression (SER) for a company's historical EBITDA. The SER is a statistical measure that is an estimate of the deviation around a 'best fit' trend line. We combine it with the profitability ratio to determine the final profitability assessment. We only calculate

SER when companies have at least seven years of historical annual data, to ensure that the results are meaningful.

Working-capital-intensive companies: Generally a company with large levels of working capital in relation to its sales in order to meet seasonal swings in working capital. Examples of working-capital-intensive sectors include retail, auto manufacturing, and capital goods.

Frequently Asked Questions

A. Volatility of cash flows

If a company exhibits volatile cash flow metrics, does Standard & Poor's capture this in the cash flow volatility adjustment or in the financial policy assessment?

We capture this in either analytic factor, as appropriate. As per paragraph 125, the volatility adjustment is the mechanism by which we factor a "cushion" of medium-term variance to current financial performance not otherwise captured in either the near-term base-case forecast or the long-term business risk assessment. We make this adjustment based on the following:

- The expectation of any potential cash flow/leverage ratio movement is both prospective and dependent on the current business or economic conditions.
- Stress scenarios include, but are not limited to, a recession, technology or competitive shifts, loss or renegotiation of major contracts or customers, and key product or input price movements, as typically defined in the company's industry risk profile and competitive position assessment.
- The volatility adjustment is not static and is company-specific. At the bottom of an economic cycle or during periods of stressed business conditions, already reflected in the general industry risk or specific competitive risk profile, the prospect of weakening ratios is far less than at the peak of an economic cycle or business conditions.
- The expectation of prospective ratio changes may be formed by observed historical performance over an economic, business, or product cycle by the company or by peers.
- The assessment of which classification to use when evaluating the prospective number of scoring category moves will be guided by how close the current ratios are to the transition point (i.e. "buffer" in the current scoring category) and the corresponding amount of EBITDA movement at each scoring transition.

As per paragraph 157, financial policy refines our view of a company's risks beyond the conclusions arising from the standard assumptions in the cash flow/leverage assessment. Those assumptions do not always reflect or entirely capture the short-to-medium term event risks or the longer-term risks stemming from a company's financial policy. To the extent movements in one of these factors cannot be confidently predicted within our forward-looking evaluation of cash flow/leverage, we capture that risk in our evaluation of financial policy.

What constitutes a period of stress when assessing whether a company has a volatile or highly volatile level of cash flow/leverage?

As guidance, our global default studies demonstrate significant correlation of defaults with weak points in business cycles and banking crises. The 1991 peak default rate occurred after a mild recession in the U.S., a severe but short recession in the U.K., and the Nordic banking crisis. Other developed-market speculative-grade default peaks were the U.S., at 10.6% in 2001 (the U.S. recession) and 11.4% in 2009 (the global banking crisis and recession); and Europe, at 12.3% in 2002 (due in part to the bursting of the technology/Internet bubble and failures of a large number of telecom start-ups). (Sources: "2012 Annual Global Corporate Default Study," published March 18, 2013, and "Understanding

Standard & Poor's Rating Definitions," published June 3, 2009.)

Additional guidance can be found in "Methodology: Industry Risk," published Nov. 19, 2013, Appendix 1 where we considered sensitivity to economic cycles, as measured by the historical cyclical peak-to-trough decline in profitability and revenues for major recessions ('BBB' and 'BB' stress) mapped to specific industry sectors.

B. Profitability

If a company operates in a region or in a country where local inflation is high, and you believe that this affects the comparability of its profitability measures with industry peers', how do you incorporate this in your assessment?

When analyzing level of profitability, we use, where available, the numeric guidance provided in key credit factors (KCF) articles. These thresholds apply globally irrespective of the underlying level of inflation, although we also consider trends in the profitability ratio to determine the level of profitability assessment. However, high inflation environments are often associated with exposure to countries with a high country risk, in which case as per paragraph 87 we may adjust the volatility of profitability assessment to account for this exposure. Finally, to the extent not captured elsewhere in the analysis, we may incorporate this factor as part of the comparable ratings analysis.

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

(Watch the related CreditMatters TV segment titled, "Standard & Poor’s Launches Its New Corporate Ratings Criteria," dated Nov. 19, 2013.)

Exhibit No. GND-4T
Docket UE-140762 *et al.*
Witness: Gregory N. Duvall

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF GREGORY N. DUVALL

November 2014

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ATTACHED EXHIBITS

Q. Are you the same Gregory N. Duvall who previously submitted direct testimony in this case on behalf of Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY

Q. What is the purpose of your testimony?

A. My testimony presents the Company's rebuttal net power costs (NPC), including updates to improve the accuracy of the pro forma NPC. I respond to the NPC-related issues raised by Mr. David C. Gomez on behalf of Washington Utilities and Transportation Commission (Commission) Staff and Mr. Bradley G. Mullins on behalf of Boise White Paper, LLC (Boise). I also respond to the testimonies of Mr. Jeremy B. Twitchell on behalf of Staff, Ms. Donna M. Ramas on behalf of the Public Counsel Division of the Washington Attorney General's Office (Public Counsel), and Mr. Mullins recommending that the Commission reject the Company's proposed renewable resource tracking mechanism (RRTM).

Q. Please summarize your testimony related to the Company's NPC update.

A. Consistent with the Commission's long-standing policy supporting NPC updates in rate cases, the Company updated its NPC to reflect the most recent data on costs for the rate-effective period. The Company's updated NPC for the west control area under the Company's West Control Area inter-jurisdictional allocation methodology (WCA) are approximately $592.7 million, or $135.6 on a Washington-allocated basis. Updated NPC are approximately $5.4 million higher than the NPC included in the initial filing on a Washington-allocated basis.

The NPC updates are similar to those included in Pacific Power's previous Washington rebuttal filings. The most significant aspect of the NPC update is an increase in the Company's coal supply costs at the Jim Bridger plant from the Black Butte and Bridger mines. I explain why this coal cost update is reasonable as a policy matter, and I support providing other parties an opportunity to respond to it in supplemental testimony. Ms. Cindy A. Crane provides details on the updated coal costs in her testimony.

Q. Please summarize your testimony responding to NPC adjustments proposed by the parties.

A. My testimony demonstrates that:

- Including power purchase agreements (PPAs) with qualifying facilities (QFs) located in California and Oregon in the Company's west control area NPC is fully consistent with state and federal energy policy supporting renewable energy development, complies with Public Utility Regulatory Policy Act of 1978 (PURPA) mandates, and is otherwise fair to Washington customers and the Company. Although it is appropriate to treat the Company's west control area QF PPAs like all other west control area PPAs, the Company includes two alternative approaches: (1) re-pricing the out-of-state QFs at Washington avoided prices to mitigate the impact of other states' policy decisions; or (2) adjusting state allocation factors to reflect the implicit assumption that a situs-assigned resource serves only the state where it is located. The parties dismissed these alternatives, but my testimony demonstrates that these alternatives respond to the

Commission's concerns in the Company's 2013 rate case and deserve serious consideration.

- The anticipated benefits from participating in the energy imbalance market (EIM) with the California Independent System Operator (CAISO) during the rate-effective period are not yet known and measurable, particularly because the EIM is conceptually incompatible with the WCA. Boise proposes to impute EIM benefits relying on a report issued by Energy and Environmental Economics, Inc. (E3 Report), which was not developed for ratemaking purposes, does not cover the pro forma period in this case, and is not specific to the west control area. In addition, Boise's adjustments include benefits that are already reflected to some extent in the Company's pro forma NPC and credit NPC for avoided within-hour costs that are not included in the hourly GRID model to begin with. It is reasonable to exclude both EIM costs and benefits from rates, consistent with the Company's initial filing.
- Inter-hour integration of load and wind resources is appropriately reflected in the Company's NPC and is not duplicated by modeling load and wind profiles on an hourly basis.
- For the purpose of setting rates, the Company uses a single-year median water year, and therefore extraordinary hydro events are not reflected in NPC and the Company has no way of recovering costs related to lower-than-median hydro. The Company forecasts that hydro output in 2014 will be about 300,000 megawatt-hours, or eight percent below the amount included in rates. The

Company's filed hydro deferral is the only mechanism available to recover the cost of lower than expected hydro generation.

- The Company's approach to the Colstrip and Chehalis forced outages allows the Company to recover its prudent power supply costs. Denying the deferral for Colstrip or removing the Chehalis outage from the four-year forced outage rate effectively denies the Company recovery for its prudent costs.
- With certain corrections, Boise's adjustment to reduce wheeling expenses related to network integration transmission service (NITS) provided by the Bonneville Power Administration (BPA) is reasonable. The Company has corrected the calculation for the pro forma period, resulting in a reduction to west control area NPC of $0.8 million.

Q. Please summarize your rebuttal testimony related to the Company's proposal for the RRTM.

A. The RRTM addresses the Company's growing fleet of renewable resources, which enable the Company to comply with Washington laws and policies requiring the development of renewable generation. The RRTM is designed to protect both the Company and customers by ensuring that customers pay no more or less than the actual costs to serve them with renewable resources. While the Company appreciates Staff's proposal for a power cost adjustment mechanism (PCAM) in lieu of the RRTM, Staff's PCAM does not address the under-recovery of renewable resource costs or negate the need for the RRTM. In response to the parties' concerns, the Company modified its proposed RRTM to prevent the possibility of NPC over-recovery by capping the potential adjustment under the RRTM at the Company's actual NPC. As a practical matter, the risk that this cap would ever be triggered is low. Since 2007, the Company has under-recovered its NPC in Washington in every year, by an average of nine percent.[1]

POLICY OVERVIEW

Q. Please address the policy issues implicated by your rebuttal testimony.

A. As described in more detail in the rebuttal testimony of Mr. R. Bryce Dalley, the Company is in a period of significant transformation as it responds to laws and regulations that have increased the development of renewable and distributed generation in the Pacific Northwest. Washington has been at the forefront of this transformation, adopting a regional approach to advance state environmental and energy policies:

- In 2006, voters enacted the Energy Independence Act (EIA), creating Washington's renewable portfolio standard (RPS) to encourage the regional development of renewable resources;[2]
- In 2007, the legislature enacted Washington's Greenhouse Gas Emissions Performance Standard (EPS) to increase the use of renewable resources to serve Washington customers;[3]
- In 2008, Washington enacted the Climate Action and Green Jobs bill to further promote renewable energy development;[4]

[1] Pacific Power's Response to Staff data request 89.
[2] RCW 19.285.020 (EIA provides that Washington should increase the use of "renewable energy facilities"). Laws of 2013, ch. 61 (amending the definition of "eligible renewable resource" in RCW 19.285.030, effective July 28, 2013). Now, RCW 19.285.030(12)(a) and (e) define "eligible renewable resource" to include facilities located in the Pacific Northwest as well as facilities in other states where the qualifying utility has a renewable resource and serves retail customers.
[3] RCW 80.80.005(1)(d).
[4] RCW 70.235.005(1).

- In 2010, the legislature directed Washington's State Energy Office to prepare a state energy strategy to "promote energy self-sufficiency through the use of indigenous and renewable energy sources, consistent with the promotion of reliable energy sources[;]"[5]
- In 2013, Washington passed a second Climate Action Bill to further reduce greenhouse gas (GHG) emissions;[6]
- In October 2013, Washington signed the Pacific Coast Action Plan on Climate and Energy to provide coordination among the states and provinces of the west coast to "link programs for consistency and predictability and to expand opportunities to grow the regions low-carbon economy;"[7]
- In April 2014, Governor Jay Inslee issued an Executive Order specifically recognizing the Washington had joined Oregon and California, "calling for additional West Coast actions on climate leadership, clean transportation, and clean energy and infrastructure."[8]

Q. Please explain how these policy issues inform the issues covered in your rebuttal testimony.

A. As described in Mr. Dalley's testimony, in this case, the Company made several proposals intended to better position the Company to respond to the challenges resulting from changing Washington state laws and policies. With respect to NPC, the Company proposed the RRTM to mitigate the risks caused by the variability in the Company's growing portfolio of renewable resources. The RRTM will ensure

[5] RCW 43.21F.010(3).
[6] Laws of 2013, ch. 6.
[7] Pacific Coast Action Plan on Climate and Energy at 1 (Oct. 28, 2013). A copy of this plan is included as Exhibit No. RBD-4 to Mr. Dalley's rebuttal testimony.
[8] Executive Order 14-04 at 2 (Apr. 29, 2014).

that both the Company and customers are protected from the volatility inherent in renewable generation.

The Company also renewed its request for a change to the WCA to allow cost recovery of all PPAs with QFs in the west control area, all of which are renewable resources.

Q. The parties argue that the RRTM and the modification to the WCA related to QF generation are contrary to Commission precedent. Why is the Company asking the Commission to take a new direction in this case?

A. To respond to the rapidly changing energy landscape in Washington, the Company urges the Commission to reconsider as necessary its prior decisions that predate or otherwise do not take into account the Washington laws now driving electric industry transformation. The recent legislative changes outlined above provide a strong basis for a different outcome in this case.

UPDATED RECOMMENDATION FOR NET POWER COSTS

Q. Have you updated the Company's recommended pro forma NPC?

A. Yes. The Commission's policy is that "power costs determined in general rate proceedings and in [power cost only] proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings."[9] Consistent with this policy, the Company updated its pro forma NPC to reflect the most current information available, including a new forward price curve; updates to several PPAs (including QF PPAs); fuel costs, including coal and natural gas supply; and updates to

[9] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket No. UE-060266, Order 08 ¶ 102 (Jan. 5, 2007).

gas transportation costs. The Company's updated NPC recommendation is required to produce the most accurate projection of west control area NPC for the pro forma period in this case (the 12 months ending March 31, 2016).

Q. What is the Company's updated NPC recommendation?

A. The Company increased its recommended west control area NPC from $568.8 million to approximately $592.7 million, an increase of $23.9 million. On a Washington-allocated basis, NPC increases by approximately $5.4 million to $135.6 million. The NPC report for the Company's rebuttal filing is presented in Exhibit No. GND-5.

Q. Have you provided an exhibit that summarizes the change in NPC from your direct testimony on a west control area basis?

A. Yes. Exhibit No. GND-6 summarizes the impact of all individual updates on west control area NPC.

Q. Please provide more detail on the updates included in rebuttal NPC?

A. The Company's rebuttal NPC study now reflects:[10]

- Updated tariff rates for the Chehalis natural gas lateral pipeline;
- Updated costs for the PGE Cove purchase contract;
- Updated coal expense reflecting changes in fuel supply costs and volume for the pro forma period;
- Updated Mid-Columbia (Mid-C) hydro contract costs;
- Changes to three small Oregon QF PPAs, including one removal, one update, and one addition;
- The Company's September 30, 2014 official forward price curve;

[10] The Company's rebuttal NPC also includes one minor correction to the price assumed for the Douglas County Forest Products QF PPA. The impact of the correction is a reduction to west control area NPC of $2,729.

- Updated short-term firm transactions executed through October 1, 2014; and
- Reduced wheeling expenses related to the Goodnoe Hills large generator interconnection agreement.

Q. Please identify the main drivers of the increase in the NPC update.

A. Compared to the Company's initial filing, the increase in NPC is predominantly due to updated coal supply costs for the Jim Bridger plant. In summary, the Company recently concluded negotiations with Black Butte mine for coal supply in the rate period, reflecting a price increase. At the same time, the Company now projects lower production from the Bridger mine in the rate period and the need to purchase additional coal from the Black Butte mine. Ms. Crane provides additional detail supporting the Company's updated coal costs.

Q. Do you believe that the NPC updates you are sponsoring satisfy the Commission's standards?

A. Yes. The updated information used in the NPC study that underlies my rebuttal testimony is indicative of the actual costs the Company will incur during the rate-effective period.

Q. Will the proposed coal supply cost updates for the Jim Bridger plant further the Commission's interest in setting NPC as closely as possible to costs reasonably expected to be incurred in the rate-effective period?

A. Yes. The updated coal cost information is the best available evidence for the expected level of coal supply costs for the Jim Bridger plant in the rate-effective period. Without the update, the estimated level of coal costs included in rates will be inaccurate and will not match other costs and revenues reflected in NPC.

Q. Did the Company significantly under-recover its NPC in 2013?

A. Yes. On a west control area basis, the Company under recovered its NPC by $33.2 million.[11] The Company's NPC update is necessary to guard against a similar outcome in the rate-effective period.

Q. Is the Company's updating of coal costs consistent with past proceedings?

A. Yes, the Company updated its coal costs as part of the NPC updates in its last two litigated cases, the 2010 and 2013 general rate cases. In the 2010 case, Docket UE-100749, the Company updated its third-party coal contracts and fuel volumes, which resulted in an increase in west control area NPC of approximately $1.1 million. Similarly, in the 2013 case, Docket UE-130043, the Company updated coal costs to reflect changes in contract costs and fuel volume, which resulted in a decrease in west control area NPC of approximately $2 million. No party objected to these updates, and the Commission approved them in its final orders.

Q. Did either of the coal cost updates in the 2010 or 2013 rate cases involve an update to Bridger coal costs?

A. In both cases the Bridger coal volumes were updated to reflect changes in the forward curve, although the price per ton was not updated. In this case, updating Bridger coal pricing is reasonable because the updated price correlates to the cost increase for the Black Butte mine, updates to which the Commission has approved in the Company's most recent cases, and is a result of changing production volumes at the Bridger mine. As described in the testimony of Ms. Crane, the updated cost per ton of coal from both the Bridger and the Black Butte mines are similar, establishing the reasonableness of the updated Bridger coal costs.

[11] Testimony of David C. Gomez, Exhibit No. DCG-5CT.

Q. Did the Company propose an update to Bridger coal costs in its 2011 rate case, Docket UE-111190?

A. Yes. While the parties objected to the update, unlike this case, the 2011 rate case did not include a parallel increase in third-party coal costs from the Black Butte mine that corroborated the reasonableness of the cost increases at the Bridger mine. In that case, the NPC witness for the Industrial Customers of Northwest Utilities (ICNU) proposed that the price of coal from the Black Butte mine be used to re-price Bridger coal in the update.[12] The parties ultimately settled the case without resolving this issue.

Q. Did Boise participate in Docket UE-111190 as a member of ICNU?

A. Yes. Recent filings in these consolidated cases make clear that Boise has participated in Pacific Power's Washington rate cases for many years as a member of ICNU and continues to do so. In Boise's Petition to Intervene in Docket UE-131384, the Company's accounting petition related to the Colstrip plant now consolidated with this case, Boise acknowledged that it had participated in nine of Pacific Power's Washington rate cases as a member of ICNU, specifically including Docket UE-111190.[13] Similarly, in April 2014, when ICNU petitioned to intervene in Docket UE-140617, also consolidated with this case, it noted that it was doing so on behalf of

[12] *Wash. Utils. & Transp. Comm'n v. PacifiCorp,* Docket No. UE-111190, Responsive Testimony of Donald W. Schoenbeck, Exhibit No. DWS-1CT at 3 ("The majority of coal supplied to the Jim Bridger plant comes from an affiliated mine. Adequate time has not been provided to assess the reasonableness of the Company's coal price updates. As a placeholder, ICNU recommends the updated price from the third party supplier be used as a price cap on the allowable Jim Bridger coal costs. This recommendation reduces the claimed revenue increase by $1.6 million.")

[13] *See Wash. Utils. & Transp. Comm'n v. PacifiCorp,* Docket No. UE-131384, Petition to Intervene of Boise White Paper, L.L.C. at 2 (Jan. 13, 2014) ("Boise directly participated in PacifiCorp's most recent general rate case and has participated, as a member of the Industrial Customers of Northwest Utilities, in other PacifiCorp rate proceedings, including UE-991832, UE-032065, UE-050684, UE-060669, UE-061546, UE-080220, UE-090205, UE-100749, and UE 111190.")

its members, "including the Packaging Corporation of America, f/k/a Boise White Paper, L.L.C. (PCA), PacifiCorp's largest customer in Washington[,]"[14] and further stated that "ICNU indirectly participated in PacifiCorp's most recent general rate case (UE-130043) as PCA[.]"[15]

Q. Given that this update is occurring in your rebuttal testimony, does the Company object to allowing the parties an opportunity to provide responsive testimony on this issue?

A. No. The Company does not object to parties addressing the Company's NPC update in supplemental pre-filed testimony or in testimony at the hearing, provided the Company has a chance to respond to this testimony.

COMPANY RESPONSES TO PROPOSED NPC ADJUSTMENTS

Exclusion of California and Oregon QF PPAs

Q. Does any party support the Company's proposal to include the costs associated with Oregon and California QF PPAs in west control area NPC?

A. No. Staff, Boise, and Public Counsel each reject including California and Oregon and QF PPAs in west control area NPC.[16] Similar to arguments made in the Company's 2013 general rate case, Staff and Boise assert that allocating west control area QF PPAs to Washington inappropriately requires Washington customers to pay for QF-related policy choices made by California and Oregon. Public Counsel does not address the appropriate allocation of California and Oregon QF PPAs, but indicates

[14] *See Wash. Utils. & Transp. Comm'n v. PacifiCorp,* Docket No. UE-140617, Petition to Intervene and Opposition of the Industrial Customers of Northwest Utilities, ¶ 3 (Apr. 25, 2014).
[15] *Id.*, ¶ 4.
[16] *See* Testimony of David C. Gomez, Exhibit No. DCG-1CT at 9-10; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 23.

that Public Counsel supports the Commission's findings in Docket UE-130043 (2013 Rate Case) and removes the cost of these QFs from west control area NPC.

Q. Is the Company's proposal in this case exactly the same as in the Company's 2013 Rate Case?

A. No. While the Company's main proposal in this case is similar to the 2013 Rate Case in that the costs associated with California and Oregon QF PPAs are included in west control area NPC, the Company also provided two alternative approaches that would reasonably reflect the impact of California and Oregon QF PPAs on NPC. First, the Company proposed re-pricing the out-of-state QFs at Washington avoided cost prices, so that the costs associated with the QFs reflected Washington state policy choices. This proposal would decrease Washington revenue requirement by $2.2 million. Second, the Company proposed a load decrement approach to QF pricing that would remove the costs of the out-of-state QF PPAs and also offset each west control area states' load with the QFs in that state for purposes of allocating costs and benefits under the WCA. This proposal would decrease Washington revenue requirement by $3.9 million. The rebuttal testimony of Ms. Natasha C. Siores provides the detailed revenue requirement impact of each proposal. I reproduced her summary table here for ease of reference.[17]

TABLE 1

Revenue Requirement Summary

	Revenue Requirement	Change from Filed	
Rebuttal Position	31,938,957		**Ref NCS-11, Page 1.1**
Re-Pricing at WA QFs Avoided Costs	29,763,224	(2,175,733)	**Ref NCS-12, Page 2**
Load Decrement	28,009,625	(3,929,332)	**Ref NCS-12, Page 3**
Situs-Assigned - Excl. OR/CA QFs	22,181,879	(9,757,079)	**Ref NCS-12, Page 4**

[17] Rebuttal Testimony of Natasha Siores, Exhibit No. NCS-12.

Q. Did the parties address the Company's alternative proposals?

A. Yes. Both Staff and Boise dismissed the Company's alternative proposals as inconsistent with the Commission's decision in the 2013 Rate Case.

Q. What is the parties' primary argument against Pacific Power's proposals?

A. Based on the Commission's order in the 2013 Rate Case, Staff and Boise argue that excluding the California and Oregon QF PPAs from the west control area NPC is equivalent to replacing these resources with market purchases in GRID.[18] Staff and Boise claim that re-pricing the QF PPAs at market prices protects Washington customers from policy decisions made by other states and is consistent with the cost causation principles underlying the WCA.

Q. Is re-pricing the out-of-state QF PPAs at current market prices consistent with PURPA?

A. No. It is my understanding that re-pricing the out-of-state QF PPAs at current spot market prices is inconsistent with PURPA's requirement, as interpreted by the Commission in the Company's Schedule 37, that utilities purchase all energy and capacity made available by QFs at the utility's avoided cost.

Q. Why is re-pricing the out-of-state QF PPAs at current market rates inconsistent with PURPA's avoided cost requirements?

A. There are two primary reasons. First, simply relying on market prices does not reflect Pacific Power's actual avoided costs as determined by the Commission because it fails to account for the impact of a QF on the Company's existing resources or the

[18] *See*, *e.g.*, Testimony of David C. Gomez, Exhibit No. DCG-1CT at 11; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 25-26.

QF's ability to defer future capacity additions. PURPA requires the Company to purchase energy and capacity made available by QFs.

Second, the *current* market price does not accurately reflect Pacific Power's avoided cost of energy included in long-term QF PPAs that were executed years ago with avoided cost prices determined at the time of execution. PURPA allows QFs to enter into long-term PPAs with utilities and, at the option of the QF, the avoided cost prices in those PPAs can be determined at the time the PPA is executed, not at the time that the energy is delivered to the utility.

The Commission's decision to price out-of-state QF PPAs at the current market price ignores the Company's obligation under PURPA to pay a fixed avoided cost price over the life of the QF PPA. Thus, even if market prices accurately reflected Pacific Power's avoided cost of energy, the relevant market prices were those that were forecast at the time the QF PPAs were executed, not current spot market prices.

Q. Has the Commission recognized that avoided cost prices must account for both energy and capacity?

A. Yes. Pacific Power's current Schedule 37 requires the Company to pay QFs in Washington for both energy and capacity, with energy payments reflecting the Company's incremental cost of market transactions and thermal output, and capacity payments reflecting the fixed costs associated with a simple cycle combustion turbine for three months per year. The inclusion of capacity payments in Washington's avoided cost calculation demonstrates that, in the current view of the Commission, market prices alone are not equivalent to avoided cost prices.

Q. Has Staff recognized that wind resources provide capacity value to Washington customers?

A. Yes. Staff's cost of service testimony expressly recognizes that wind resources provide capacity to meet the Company's peak load.[19] As described in the cost of service testimony of Ms. Joelle R. Steward, the Company's west control area wind resources, including the out-of-state QFs, contribute 25.4 percent of their nameplate capacity to meet total system peak load.

Q. Why is it necessary for the avoided cost prices to account for both energy and capacity?

A. It is my understanding that PURPA mandates the use of avoided cost prices to ensure customer indifference to the QF transaction. In other words, customers should be no better or worse off because Pacific Power is purchasing its energy and capacity from a QF rather than from another source. However, if Washington customers are paying for only the energy from out-of-state QFs, Washington customers are benefiting from the capacity value provided by the QFs without paying for it. Therefore, re-pricing the out-of-state QF PPAs at market prices does not result in customer indifference.

Q. Has the Commission previously recognized the importance of ensuring customer indifference?

A. Yes. The Commission has observed that "[b]y its own terms, PURPA was meant to protect the ratepayers. Avoided cost prices should be established to be no greater than that which the ratepayers would be expected to pay without PURPA."[20]

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[19] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 15-16.
[20] *Spokane Energy, Inc. v. Wash. Water Power Co.*, Cause No. U-86-114, 1987 WL 1498338 (Apr. 22, 1987).

Q. How do current market prices compare with the market prices at the time the QFs were executed?

A. The majority of the out-of-state QFs were executed within the last six years. During that time, market prices have decreased by more than half. Thus, even if the Commission's re-pricing method was reasonable for purposes of determining the avoided cost of energy, the contracts must be re-priced at the higher market prices that were anticipated at the time each PPA was executed. The Company's re-pricing proposal effectively captures the relevant forward prices and demonstrates the declining market prices.

Q. Staff claims that the Company provided only vague assertions regarding the benefits provided by the out-of-state QFs to Washington customers.[21] Boise claims that the Company did not identify any direct benefit provided by these QFs that would support full cost recovery.[22] What benefits are provided by the out-of-state QFs?

A. In addition to providing the capacity benefits discussed above, the out-of-state QFs provide significant benefits because they are renewable, emission-free generators. Washington state policymakers have been clear that renewable generation provides significant environmental, cultural, economic, and health benefits to Washington residents. Thus, the state has taken extensive measures to mandate and promote the development of exactly the types of resources that Staff and Boise claim provide no benefit to Washington.

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[21] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 9.
[22] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 26.

Emission-free resources may act as a hedge against future carbon regulation, the exact nature of which is currently unknown. In fact, the Commission has acknowledged that future carbon regulation may have a significant impact on the Company's operations.[23] The out-of-state QFs, like all of the Company's renewable resources, will help to mitigate that impact.

Q. What other benefits are provided by the out-of-state QFs?

A. The QFs provide diversity to the Company's resource portfolio, which can act to reduce risk. Indeed, *in this case* Mr. Mullins testified on behalf of Boise about the many benefits provided by wind resources, including the out-of-state QFs:

> Portfolio diversification is one of the fundamental principles relied on by utilities in order to develop a least-cost, least-risk portfolio . . . . For purposes of utility planning, this means that a utility will benefit from procuring power supplies that are dependent on many different fuel and resource types.[24]

Thus, Mr. Mullins concluded that the Company's "overall system is benefiting as a result of the diverse nature of all the resources in its portfolio."[25]

Q. Do the QFs allow the Company to avoid other costs?

A. Yes. Without the energy and capacity provided by the QFs, Pacific Power may have had to procure additional resources. These additional resources may or may not have been renewable, yet under the WCA these resources would have been included in Washington rates.

Q. Are there any other benefits provided by QFs?

A. Yes. In a docket before the Public Utility Commission of Oregon (OPUC), Boise's

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[23] *See, e.g.*, *PacifiCorp's 2013 Electric Integrated Resource Plan*, Docket No. UE-120416, Commission Acknowledgement Letter (Nov. 25, 2013).
[24] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 57.
[25] *Id*. at 58.

energy trade association ICNU submitted testimony from its expert Mr. Donald W. Schoenbeck. ICNU's testimony identified 11 different benefits provided by QFs, including the following:

> The second benefit is reliability. A system of 50 smaller generators of 200 MW each is significantly more reliable than a similar size system of 20 larger generators of 500 MW each. The smaller unit system is 100 times less likely to lose 1,000 MW of capacity simultaneously.
>
> * * *
>
> The fourth benefit is system diversity. Because they distribute electrical generation among smaller, more efficient generating facilities, policies that promote cogeneration increase the reliability of an energy portfolio in the same way a diversified investment strategy protects investors.
>
> * * *
>
> The fifth benefit is transmission reliability. Cogeneration provides a major source of distributed generation for the electric grid which is a significant operating benefit. By providing multiple power sources throughout the state, the demand on the state's electrical grid and the risks of losing power when centralized generating facilities fail is reduced.
>
> * * *
>
> The eighth benefit is reduced transmission losses. Cogeneration conserves electricity by producing power near the places it is consumed. This reduces transmission losses and saves an additional amount of fuel from being burned.[26]

Q. Boise also claims that whether or not the out-of-state QF prices are excessive is irrelevant to cost allocation under the WCA.[27] How do you respond?

A. PURPA makes the QF prices extremely relevant. PURPA requires the Company to contract with the out-of-state QFs at prices equal to Pacific Power's avoided cost. The fact that not a single party in this case has argued that the QF PPA prices exceed

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[26] *Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, OPUC Docket No. UM 1129, Direct Testimony of Donald W. Schoenbeck on Behalf of the Industrial Customers of Northwest Utilities at 6-7 (Aug. 3, 2004).

[27] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 26.

Pacific Power's avoided cost prices is significant because, without such a finding, it is unreasonable to exclude the QF PPAs from rates.

Q. Staff and Boise also argue that the out-of-state QF PPA prices are driven by policies and decisions made by other states to encourage QF development that should not impact Washington rates.[28] Boise further claims that states have significant leeway in implementing PURPA to "set avoided cost rates at higher or lower levels to reflect state renewable energy policies."[29] How do you respond to these claims?

A. I disagree with Staff and Boise for several reasons. First, I disagree with the implication that California and Oregon have inflated the avoided cost prices in the QF PPAs as a reflection of those states' renewable energy policies. It is my understanding that states cannot set an avoided cost price that includes a "bonus" or "adder" intended to encourage renewable development. FERC has stated:

> [T]the State can pursue its policy choices concerning particular generation technologies consistent with the requirements of PURPA and our regulations, **so long as such action does not result in rates above avoided cost**.[30]

Moreover, no party to this case demonstrated or even alleged that the avoided cost prices included in the out-of-state QF PPAs are greater than the Company's actual avoided costs as of the time the PPAs were executed. Thus, there is no basis to conclude that California and Oregon are manipulating the avoided cost prices to promote state-specific energy or environmental policies.

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[28] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 9-10; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 24.
[29] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 27.
[30] *Re So. Calif. Edison Co.*, 70 F.E.R.C. ¶ 61,215 at 61,676 (1995) (emphasis added).

Second, it is my understanding that PURPA is specifically intended to encourage QF development. Therefore, Staff's and Boise's argument has merit only if one assumes that Washington has decided to not encourage QF development, a decision that would be contrary to the fundamental purpose of PURPA and contrary to the Commission's prior statements.

Third, as I discussed previously in my testimony, the states' energy policies are strikingly similar and Washington has taken a decidedly regional approach to encouraging renewable energy development. Both Oregon and Washington, for example, have used PURPA development to promote distributed generation. Therefore, the policy differences perceived by Staff and Boise are not as extensive as they claim.

Fourth, if the Commission remains concerned that the avoided cost prices of the California and Oregon in the QF PPAs reflect those states' policy decisions, then the Commission should approve the Company's alternative recommendation to re-price the QF PPAs at avoided cost prices determined according to Washington state policy. As described in more detail below, this re-pricing proposal effectively removes any perceived differences in PURPA implementation and results in Washington rates that indisputably reflect Washington state policy decisions.

Q. Staff and Boise claim that the Company's proposal is based on the "physical flow of power" and not cost causation.[31] How do you respond?

A. I disagree with this characterization. In my testimony, I stress the fact that the out-of-state QFs provide energy and capacity to serve Washington customers because that

[31] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 10; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 25.

fact—which is undisputed—demonstrates that Washington customers are benefiting from the QFs. As I discuss above, if Washington customers are receiving energy and capacity from these QFs, along with all of the other benefits discussed, then it is reasonable for Washington customers to pay the full costs of the QF PPAs. Otherwise, Washington customers are receiving the benefits without paying the associated costs. Thus, the Company's proposal is consistent with principles of cost-causation.

Q. Staff also discounts the fact that the Commission has allowed Avista Corporation d/b/a Avista Utilities (Avista) to recover the full costs of out-of-state QF PPAs in Washington rates, claiming that the Commission has not always relied on cost causation when allocating costs across multiple states.[32] Staff claims that the Company's out-of-state QF costs are higher than Avista's and therefore must be situs assigned. Do you agree?

A. No. There is no principled basis to allow one Washington utility to recover out-of-state QF costs while denying Pacific Power recovery of the same types of costs. PURPA contains no materiality threshold governing cost recovery. Consistency in regulation requires consistent treatment for all utilities. Simply pointing out that Avista has had fewer out-of-state QFs does not support differing treatment.

[32] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 13.

Q. Staff also claims that the Commission can disregard cost causation based on the degree to which state-specific policies may be driving the avoided cost prices. To support this claim, Staff relies on a 1983 Washington Water Power Company order regarding the allocation of costs for an Idaho QF PPA.[33] Does that order support Staff's position in this case?

A. No. Contrary to Staff's claim that the Commission situs assigned the Idaho QF PPA costs to Idaho, a careful reading of the Commission's order shows that the Commission did not situs assign the QF costs at all. Rather, the Commission determined that the avoided costs in the QF PPA were excessive and disallowed cost recovery of the amounts that exceeded Washington Water Power's avoided costs. In other words, the Commission applied the Company's alternative proposal and re-priced the QF PPA at Washington avoided cost prices.

Q. What is the basis for your conclusion that the Commission re-priced the QF PPA at Washington's avoided cost prices?

A. The issue presented in the case was whether Washington Water Power's proposed rate revision, which would have included the full Washington-allocated costs of the QF PPA, was just and reasonable. The Commission observed that, "[i]n reaching this ultimate determination, the commission must make the underlying determination whether the proposed purchase agreement is based on a proper methodology to calculate the avoided cost as defined by federal and state laws and rules."[34] Thus, the

[33] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 10 (citing *Wash. Utils. & Transp. Comm'n v. Wash. Water Power Co.*, Cause No. U-83-14, Second Suppl. Order, 56 P.U.R.4th 615 (Nov. 9, 1983)).
[34] *Wash. Utils. & Transp. Comm'n v. Wash. Water Power Co.*, Cause No. U-83-14, Second Suppl. Order, 56 P.U.R.4th 615, 1983 WL 909042 at 2 (Nov. 9, 1983).

Commission analyzed whether the avoided cost prices in the QF PPA were consistent with PURPA. The Commission did not simply situs assign the costs to Idaho.

In the Washington Water Power case, Staff concluded that the rates in the QF PPA were higher than Washington Water Power's avoided cost and therefore inappropriate. The Commission agreed, concluding that the "amount to be paid under the purchase agreement is in excess of properly determined avoided costs."[35] Thus, the Commission disallowed cost recovery of the amounts that exceeded the avoided cost price as determined by the Commission. Applying the same standard to this case would require approval of the Company's Washington re-pricing proposal.

Q. Staff testifies that in the Washington Water Power case, the QF PPA "pricing and terms were driven by Idaho state policies at the time."[36] Do you agree with this characterization of the order?

A. No. Nowhere in the order does it suggest that the avoided cost price in the QF PPA was the result of Idaho state policies. In addition, Staff testifies in this case that once the Commission chose to situs assign the costs to Idaho, the Idaho commission accepted that decision. Again, however, the Commission did not situs assign the costs to Idaho, and the order says nothing about how the Idaho commission responded to the Commission's order.

Q. Staff and Boise reject the Company's alternative proposal to re-price the out-of-state QF PPAs as if they were Washington QF PPAs. What is the basis for their rejection of this proposal?

A. The parties argue that this proposal is inconsistent with cost causation and merely

[35] *Id*. at 8.
[36] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 13 n. 24.

discounts the cost impact of state policy decisions made by California and Oregon.[37] Boise also claims that the Washington re-pricing proposal still burdens Washington customers with other states' energy policies because there is no way to know if the out-of-state QFs would have been developed if they had been subject to Washington's PURPA policies.[38]

Q. Does the Company's re-pricing proposal require Washington customers to pay rates that reflect policy decisions made by other states?

A. No. Re-pricing the QF PPAs at Washington avoided cost prices mitigates concerns that the avoided cost prices for the QF PPAs are driven by policy choices made by other states. The use of the avoided cost pricing for QF PPAs is intended to keep customers indifferent to the QF transaction. If the QF PPAs are re-priced at the amount that this Commission has found will result in customer indifference, then customers will be no better or worse off than they would be without the QF PPA. The parties' concerns that the re-pricing proposal still reflects other state's policy decisions has merit only if one assumes that the Commission's avoided cost prices are excessive. The re-pricing proposal, therefore, ensures that Washington rates reflect only the decisions of Washington policy makers.

Q. Doesn't the fact that customers rates will increase by $7.6 million under your re-pricing alternative suggest that the parties' concern has merit?

A. No. The fact that customer rates will increase if they pay the avoided cost prices determined by the Commission suggests that situs assignment of California and

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[37] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 15-16; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 29-30.

[38] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 30.

Oregon QF PPAs has allowed Washington customers to receive benefits for which they have not paid.

Q. Is there any precedent for this type of re-pricing?

A. Yes. As discussed above, the Commission used this approach in the 1983 Washington Water Power case relied on by Staff. It is also my understanding that the North Carolina Utilities Commission (NCUC) took this same approach to a QF PPA that was approved by the Virginia State Corporation Commission (VSCC). The NCUC analyzed the QF PPA and concluded that the pricing exceeded the utility's actual avoided costs.[39] The NCUC therefore denied cost recovery of the amount that the NCUC found to be greater than the utility's avoided costs. It is my understanding that on judicial review, the North Carolina Supreme Court affirmed the NCUC's order, concluding that the disallowance "does not violate PURPA to the extent it only excludes the amount *above* avoided costs."[40]

I also understand that the OPUC approved a stipulation for Idaho Power Company that required Idaho Power to re-price its Idaho QF PPAs to reflect Oregon's non-levelized pricing policy.[41]

Q. Has any party alleged that the Washington avoided cost prices used in the re-pricing alternative proposal do not accurately reflect the Commission's avoided cost prices in effect at the time the out-of-state QFs were executed?

A. No. There is no basis in the record to conclude that the re-pricing does not reflect the

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[39] *Re N. Carolina Power*, E-22, SUB 333, 1993 WL 216264 (Feb. 26, 1993) *aff'd sub nom. N. Carolina Power,* 450 S.E.2d 896.

[40] *State ex rel. Utilities Comm'n v. N. Carolina Power*, 338 N.C. 412, 450 S.E.2d 896, 900 (1994). Importantly, as I discuss above, since this case, FERC has been clear that PURPA prohibits inflating the avoided cost price as the VSCC apparently did to promote state policies.

[41] *Re Idaho Power Co.*, Docket No. UE 257, Order No. 13-166 (May 6, 2013).

costs that would have been incurred if the out-of-state QF PPAs had been executed in Washington.

Q. Staff and Boise both reject the Company's alternative load decrement proposal because they claim it is based on power flows, not cost causation.[42] How do you respond?

A. The load decrement approach is consistent with cost causation. No party disputes that the out-of-state QFs serve Washington customers. Washington customers, however, are not paying their fair share of the costs by paying only current market prices. The load decrement alternative is intended to account for this fact by allocating additional costs to Washington to reflect the benefits Washington customers receive.

Q. Boise claims that the load decrement approach is unreasonable because it would assign more transmission costs to Washington customers even though the presence of QFs in California and Oregon does not reduce those states' use of the Company's transmission network.[43] Does this claim have merit?

A. No. Again, no party disputes that the QFs located in California and Oregon serve Washington customers. As discussed above, Boise's trade group, ICNU, previously testified before the OPUC that distributed generation, like the out-of-state QFs, typically decreases the need for transmission because the electricity is generated closer to load. This is particularly true for the out-of-state QFs because they are typically located closer to California and Oregon load and therefore use less transmission to serve that load. So it is reasonable to credit out-of-state customers for reduced transmission usage due to the QF development in those states.

[42] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 15; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 29.
[43] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 29.

Q. Boise claims that it would be unjust, unreasonable, and illegal to include the costs of the out-of-state QF PPAs in rates, in part, because the Commission does not have jurisdiction over the QFs.[44] Is it your understanding that the Commission must have jurisdiction over PPA counterparties to allow cost recovery of the PPAs in rates?

A. No. Most, if not all, of the Company's long-term PPAs are with counterparties that are not public utilities regulated by the Commission. Nevertheless, the costs of these PPAs are regularly recovered in rates. In addition, PURPA specifically exempts QFs from regulation by state utility commissions.

Q. What is the Company's recommended treatment of the costs associated with California and Oregon QF PPAs in west control area NPC?

A. The Company recommends that the Commission allow the Company to include the costs of California and Oregon QF PPAs in west control area NPC in the same manner as all other west control area generation resources, with a portion of the costs allocated to Washington customers. Alternatively, the Company proposes the out-of-state QF PPAs be re-priced using Washington avoided cost prices and then included in the determination of west control area NPC or that the Commission adopt the proposed load decrement adjustment.

Energy Imbalance Market

Q. Please describe Boise's adjustment to NPC related to the EIM.

A. Boise proposes to reduce Washington NPC by more than $5 million based on the Company's participation in the EIM, while also including certain EIM-related costs. Boise proposed this NPC reduction in October 2014 before the EIM even began

[44] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 25.

actual binding operations in November 2014. The adjustment is highly speculative, especially under the WCA, and improper under Washington's known and measurable standard.

EIM Background and Status

Q. What is the EIM?

A. The EIM is a real-time market administered by a single market operator, the CAISO. The EIM uses an economic dispatch model to issue instructions to participating generating resources to meet the load for the entire EIM footprint. By participating in the EIM, the Company expands the CAISO's security-constrained, least-cost dispatch for most of California to include PacifiCorp's six-state platform, including additional portions of California, as well as Idaho, Oregon, Utah, Washington, and Wyoming.

Q. When did the CAISO and PacifiCorp initiate the EIM?

A. In February 2013, PacifiCorp and the CAISO announced a memorandum of understanding on the EIM, culminating work that began in fall 2012 when the Western Interstate Energy Board's PUC EIM Group (composed of utility commissioners from 12 states, including Washington) requested proposals for a real-time imbalance market.

Q. Why did the Company decide to move forward with the CAISO to participate in the EIM?

A. Developing the EIM using the CAISO's proven state-of-the-art technology and large market platform was more cost-effective, more efficient, and involved less risk than creating an entirely new model.

Q. What benefits does PacifiCorp hope to achieve for customers from the EIM?

A. The expected benefits of an EIM include (1) the economic efficiency of an automated five and 15 minute dispatch, (2) savings due to diversity of loads and variable resources in the expanded footprint, and (3) reduced operational risk from enhanced system reliability. The EIM should enhance reliability, more efficiently integrate renewable resources, and reduce costs for customers.

Q. Are the EIM's benefits a function of the size and scope of its footprint?

A. Yes. The EIM's viability and benefits come from combining the Company's transmission system, now the largest system owned by a single entity in the west, with the CAISO's system, which covers most of California. The benefits of the EIM are expected to increase as new utilities join, and NV Energy is slated to join the EIM in late 2015. Conversely, if PacifiCorp or the CAISO limited their participation in the EIM, its viability and benefits would be diminished.

Q. What is the current status of EIM implementation?

A. The EIM had a "soft start" on October 1, 2014. After running the EIM for a month under non-binding conditions, the market became financially binding on November 1, 2014.

General Objections to EIM Benefit Imputation

Q. Did the Company include EIM costs or forecasted NPC benefits in this case?

A. No. As stated in my direct testimony, the Company did not include EIM costs or benefits in this case. While EIM costs for the rate period are generally ascertainable, it is impossible at this point to accurately project the amount of offsetting benefits in the rate period. Following Washington's known and measurable standard and its adherence to the matching principle, the Company elected to exclude both EIM costs and benefits from this case. For this reason, the Company did not include a request for a prudence determination for its participation in the EIM in this case.

Q. Why can't the Company project EIM benefits for the rate period?

A. The EIM's real-time market is the first of its kind in the west. The EIM is unlike other forecast items in this case because there is no actual or analogous historical data on which to base an economic forecast for ratemaking purposes. In addition, given the EIM's new and untested nature, the Company expects that a reasonable ramp-up period will be required before EIM benefits are fully realized.

Q. Does the EIM report upon which Boise relies for its adjustment in this case analyze the EIM's benefits after the 2015-2016 start-up period?

A. Yes. Boise's adjustments are almost exclusively based on the E3 Report, which analyzes EIM benefits beginning in 2017. The E3 Report was issued in March 2013, based on dated information and assumptions.

Q. Does Washington's use of the WCA further complicate the projection and assignment of EIM costs and benefits to Washington?

A. Yes. The WCA requires a second set of speculative projections regarding the potential costs and benefits during the start-up phase of a hypothetical EIM limited to PacifiCorp's west control area. Even assuming an EIM using only one of the Company's balancing authority areas was viable, because the expected benefits of the EIM are correlated to its scale, a hypothetical WCA-only EIM will produce proportionately less benefits than a full-system EIM.

In addition, the benefits of the EIM and the manner in which it will deploy the Company's integrated system resources calls into question the fundamental assumptions underlying the WCA. The premise of the WCA is that the resources in the east control area provide little to no direct or indirect benefits to Washington. The EIM, however, will produce benefits based on the optimization of the Company's entire system—both west and east control area resources. Given that the Commission has concluded that the east-side resources provide no benefits to Washington, it is reasonable to also conclude that the optimization of those resources through the EIM provide no benefits to Washington. Thus, the imputation of EIM benefits in this case is incompatible with the WCA.

Q. Is the Company's approach to the EIM in this case generally similar to the approach adopted in other jurisdictions?

A. Yes. In Oregon, the Company and intervenors agreed to set EIM benefits included in NPC for Oregon in 2015 equal to EIM costs. In that case, Mr. Mullins was the witness for Boise's energy trade association ICNU and testified that the Oregon EIM settlement was reasonable given the difficulty of quantifying EIM benefits in 2015.[45] The Company's proposal here effectively produces the same result as the Oregon settlement supported by Mr. Mullins.

In Utah, the Company and intervenors agreed to a settlement where EIM benefits were excluded from NPC and allowed to pass through the Company's energy balancing account.

[45] *In re PacifiCorp*, OPUC Docket Nos. UE 287 and UM 1689, Joint Testimony in Support of Stipulation at 8, 12 (Aug. 14, 2014) ("The Settling Parties agree that, at this time, the costs and benefits associated with the EIM are difficult to predict with certainty. As an interim approach, the Settling Parties agree that it is reasonable to offset EIM costs and benefits in 2015 NPC…. [O]ffsetting the costs and benefits associated with the EIM appropriately balances possible risks and benefits during the first full year of the EIM's operation.").

Q. What are the specific EIM benefits alleged by Boise?

A. Boise alleges four distinct types of benefits, three of which were identified in the E3 report: inter-regional dispatch, intra-regional dispatch, and reserve diversity. Boise included an additional category called "within-hour dispatch." Boise's combined EIM adjustments reduce west control area NPC by $21.8 million, or $5.1 million on a Washington-allocated basis.

Q. Do you have an overarching criticism of Boise's proposed adjustments to NPC for EIM benefits?

A. Yes. Boise relies primarily on the results of the E3 Report without regard to its applicability to the specific pro forma period in this case or the WCA methodology. The adjustments include benefits that are already reflected to some extent in the Company's existing forecast. Furthermore, Boise's adjustments reflect a reduction in imbalance costs that are not included in the GRID model forecast or customers' rates to begin with.

Q. Is the E3 Report, on which the Company based its decision to pursue the EIM, appropriate for use in ratemaking?

A. No. The Company used the E3 Report to verify that the EIM would be cost effective, not as a study to quantify its near-term benefits for ratemaking. The E3 Report is based on a WECC-wide forecast for 2017, with corresponding loads and market prices, though the benefits are adjusted to 2012 dollars. The benefits determined by the E3 Report are thus dependent on the costs of system operation in 2017 and do not reflect costs included in the Company's forecasted NPC. Differences include essential assumptions no party would accept for use in GRID in this rate case including different test period, forward price curves, transmission topology, and differences in the underlying production dispatch model and associated model architecture.

In this way, the E3 Report is comparable to an Integrated Resource Plan, which is a planning study that is not used for ratemaking. In the Commission's November 2013 letter acknowledging the Company's 2013 Integrated Resource Plan, the Commission specifically recognized that "it is too early in the process for the Company to project the exact impacts that the EIM will have on [PacifiCorp's] strategy and its ratepayers."[46]

Q. Boise contends the Company should use its best forecast in establishing NPC for the pro forma period. Do you agree?

A. Yes.

Q. Will all of the resources that were assumed to be bid into the EIM in 2017 in the E3 Report be available to be bid into the EIM during the pro forma period?

A. No. The majority of natural gas resources, some wind resources, and some coal resources were available to be bid into the EIM beginning November 1, 2014. Additional resources will be available to be bid into the EIM as planned outages occur during 2015 and 2016 and required upgrades can be completed. Exhibit No. GND-7 identifies the resources that were available to bid into the EIM as of November 11, 2014. As seen in the exhibit, the majority of the resources are not included in the west control area.

[46] *PacifiCorp's 2013 Electric Integrated Resource Plan*, Docket No. UE-120416, Commission Acknowledgement Letter (Nov. 25, 2013).

Q. What is the Company's best forecast of EIM benefits for the pro forma period?

A. The Company does not have a good forecast of EIM benefits based on known and measurable data comparable to other inputs into the GRID model used to project NPC in base rates.

Q. Apart from modeling debates, what else should the Commission consider in deciding whether to include EIM benefits in rates?

A. As noted above, there is further upside potential in the form of lower costs and enhanced reliability for customers if other balancing authorities join the EIM. If the Commission's action in this proceeding is perceived to be a penalty to the Company for taking an innovative leadership action to reduce customer costs, the likelihood of other utilities joining the EIM, or at least speed at which other utilities join, will diminish, thereby diminishing the likelihood of increased benefits. Imputing benefits into rates that exceed a reasonable known and measurable standard would be viewed by any utility as a penalty and would provide a strong disincentive to utilities seeking innovative ways to reduce their costs.

Q. Is it reasonable to make line-by-line adjustments to the various items in the E3 Report to adjust for the uncertainty and non-matching aspects of the E3 Report to the rate case?

A. No. The Company does not support using a discounted approach to the E3 Report to arrive at an appropriate forecast of EIM benefits to use in setting in rates. Any judgment applied to arrive at a discount would necessarily be highly subjective. Nonetheless, the Company provides additional discussion of risks and uncertainties associated with the line items in the E3 Report to further support the Company's position against imputation of forecast EIM benefits in this case.

Q. Are there other studies that could provide insight on expected EIM benefits?

A. No. Boise cites a Southwest Power Pool (SPP) study that found first-year SPP EIM benefits were 20 percent higher than forecast.[47] But the study summary indicates—and Boise neglects to mention—that this was primarily attributed to higher gas prices than were assumed in the forecast. Thus, to the extent market prices, hydro conditions, resource availability, transfer capability, and loads differ from the levels assumed in the E3 Report, the EIM benefits will be impacted.

Objections to Imputing Benefits for EIM Inter-Regional Dispatch

Q. What inter-regional dispatch benefits are contemplated in the EIM?

A. Inter-regional dispatch reflects the value of energy transactions between the CAISO and PacifiCorp. As a result of the EIM, CAISO and PacifiCorp are expected to be able to transact more frequently using transmission capacity between CAISO and PacifiCorp at the California-Oregon Intertie (COI). Inter-regional dispatch benefits result when CAISO and PacifiCorp can transact at a higher sale price and lower purchase price with each other than is available from their internal resources. The Company would be both a buyer and a seller at different times, depending on system conditions.

Inter-regional benefits are highly dependent upon transfer capability between the CAISO and PacifiCorp. The E3 Report evaluated benefits from a range of 100 MW to 800 MW of bi-directional five-minute dynamic transfer capability between CAISO and PacifiCorp at the COI. In practice, due to constraints imposed

[47] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 34.

by the Bonneville Power Administration, who is the path operator on the north side of COI, the EIM transfers result from a combination of five-minute and 15-minute market instructions. Currently and temporarily, however, this transfer capability has been limited to 15-minute EIM transfers on a basis up to approximately 400 MW bi-directional.[48] These 15-minute transfers are not as valuable as five-minute dynamic transfers and do not correlate to the E3 Report as Boise suggests.

Q. Does the Company's pro forma NPC already reflect certain inter-regional dispatch benefits?

A. Yes. The Company's filing includes 108 aMW of transactions delivered to the California-Oregon Border (COB) market and 20 aMW of transactions received from the COB market. These transactions use the same transmission capacity contemplated for inter-regional transfers in the E3 Report. The majority of the transactions reflect system balancing decisions by the GRID model, which optimizes the dispatch of PacifiCorp generation against market transactions, much like what will occur under the EIM.

Q. Do you agree with Boise's proposal to allocate the inter-regional dispatch savings between the Company's west and east control areas in proportion to the load of each control area?[49]

A. No. The inter-regional dispatch benefit has no direct relationship to load, as it is a result of changes in generation dispatch and associated market transactions. The Company's east control area has more dispatchable generation with a range of fuel

[48] Up to 432 MW southbound and 331 MW northbound for the combination of five-minute dynamic and 15-minute static scheduling. These values are further limited at times due to planned and unplanned transmission outages.
[49] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 35.

costs from low-cost coal through high-heat-rate peaking gas plants. As a result, the east control area will frequently have some units that are close to the system incremental cost and could benefit from EIM dispatch. On a total-company basis, 46 percent of the Company's resource need for 2015 is expected to be met by generation currently being dispatched within the EIM. The west control area is more heavily dependent on market transactions, so there may be fewer opportunities for EIM redispatch of west control area resources. Only 24 percent of the Company's west control area resource need in the pro forma period is expected to be met by generation dispatched within the EIM. In addition, Boise's adjustment is based solely on the E3 Report outcome, and does not incorporate the associated transaction volumes or any generation impacts in the GRID model, so it is unclear how the benefits are expected to materialize. Since it is lacking a concrete demonstration of the expected benefits, this aspect of Boise's adjustment is clearly not known and measurable and should be rejected.

Objections to Imputing Benefits for EIM Intra-Regional Dispatch

Q. How was the intra-regional dispatch benefit calculated in the E3 Report?

A. Before April 1, 2009, the CAISO operated under zonal pricing, with units committed based on the zonal prices that ignored transmission constraints, but dispatched based on the actual transmission capability. Starting on April 1, 2009, the CAISO operated with nodal pricing, with both commitment and dispatch decisions based on actual transmission capabilities. A study of the market outcomes before and after the transition found an estimated annual cost reduction of $105 million as a result of the transition to nodal pricing.[50] To estimate the savings to the Company, the E3 Report pro-rated the result based on the CAISO peak load at the time of the study and the Company's peak load in 2017.

Q. Is the CAISO system comparable to the Company's system?

A. No. In 2009, the CAISO system had 258 natural gas generators, whereas the Company has just twelve, only three of which are in the west control area. That represents just one percent as many natural gas plants in the west control area compared to the CAISO, so pro-rating the estimated benefits of dispatching those gas plants based on a west control area load share of approximately seven percent likely overstates the potential benefits.

Q. Does the Company's pro forma NPC incorporate the costs of zonal pricing, i.e. ignoring transmission constraints?

A. No. The Company's pro forma NPC are developed using the GRID model, which already employs nodal dispatch. As with the model used in the E3 Report, GRID assumes perfectly efficient operations: subject to transmission constraints, in every hour the lowest cost resources will be dispatched. In addition, the Company's gas plant "screening" process optimizes the commitment of each gas unit based on its actual contribution to system costs, accounting for the nodal value at the point of delivery, rather than based on prices at a potentially distant regional market point. Therefore, the Company's pro forma NPC already incorporates intra-regional dispatch savings compared to the Company's actual operations. Boise's criticism of

[50] Frank A. Wolak, 2011, "Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets, *American Economic Review* 101: 247-252. Accessed November 13, 2014: http://web.stanford.edu/group/fwolak/cgibin/sites/default/files/files/benefits_of_spatial_granularity_aer_wolak.pdf

the Company's current generator dispatch practices is irrelevant because the costs associated with those practices are not reflected in the Company's pro forma NPC. While the Company may experience benefits from EIM in its actual operations, those benefits will only bring actual costs closer to the ideal dispatch calculated in the GRID model.

Q. What evidence does Boise provide in support of its intra-regional dispatch adjustment?

A. Boise provides no evidence related to the changes in the Company's commitment and dispatch practice as a result of EIM implementation. Instead, Boise calculates the benefits of allowing the GRID model to make unlimited system balancing sales at the COB and Mid-Columbia markets.[51] Increasing market transactions between CAISO and the Company is irrelevant to intra-regional benefits since they are unaffected by the transfer capability between CAISO and the Company. Initially, the Company only anticipates EIM interchange at COB, so it is unclear why Boise expects the EIM to create opportunities for additional bilateral transactions at other market hubs. While NV Energy has expressed interest in joining the EIM, no other parties have made commitments to join and it is unlikely another party could enter the EIM before the end of the pro forma period in this proceeding. Even if an additional party joins the EIM, the Company would receive inter-regional dispatch benefits as a result of additional transaction opportunities, not intra-regional dispatch benefits.

Q. Please summarize your position regarding the intra-regional dispatch adjustment.

A. Boise's intra-regional dispatch adjustment has little relation to the cost savings by the

[51] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 39.

same name calculated in the E3 Report. The E3 Report found fuel cost savings as a result of using more efficient generators and accounting for transmission constraints in the decision to start up a resource, both of which are already accounted for in the Company's pro forma NPC. Boise found cost savings by allowing for unlimited market transactions up to transmission limits, which better describes the inter-regional dispatch adjustment described above. Boise presents no evidence that unlimited market transactions are reasonable, double-counts the benefits of increased market transactions, and provides no evidence that the Company's forecasted intra-regional dispatch costs are overstated, either with or without EIM. For those reasons Boise's adjustment should be rejected.

Objections to Imputing Benefits for EIM Reserve Diversity

Q. What are the benefits of flexible reserve diversity as contemplated in the EIM?

A. Flexibility reserve benefits reflect the benefit of reduced flexibility reserve requirements over the combined EIM footprint. Like inter-regional benefits, flexibility reserve benefits are highly dependent upon transfer capability between the CAISO and PacifiCorp.

Q. How is the flexibility reserve diversity benefit allocated in the E3 Report?

A. The Company's share of the flexibility reserve diversity benefit is allocated based on the ratio of the Company's stand-alone reserve requirement to the total reserve requirement of the Company and the CAISO without the EIM.

Q. How much flexibility reserve diversity benefit did the E3 Report predict?

A. According to the E3 Report, PacifiCorp's flexibility reserve requirements will be reduced by 19 MW under the 100 MW transfer capability scenario, and by 78 MW under the 400 MW transfer capability scenario. These values reflected the E3 Report assumption that only 80 percent of the theoretical reserve savings could be achieved given the five-minute granularity of the EIM market. Reserves needed over shorter time frames would have to be provided with internal resources.

Q. Are flexibility reserve diversity benefits currently expected to be lower than predicted in the E3 Report?

A. Yes. At present, most of the Company's EIM transfer rights only allow for 15-minute static transfers, so the reserve diversity savings will be lower than with five-minute transfers that form the basis of the E3 estimate.

Q. How much flexibility reserve savings does Boise predict for the west control area?

A. Boise assumed that 100 percent of the theoretical reserve savings would be achieved and allocated these benefits to the west control area based on the ratio of west control area load to system load.[52]

Q. Is it appropriate to allocate flexible reserve benefits to the west control area based on load?

A. No. This overstates the total reserve savings and overstates the savings that will be allocated to the west control area. The E3 Report and CAISO EIM business practice allocate the flexibility reserve benefit based on the reserve need under independent operation. Because the east control area has more wind resources, it has a relatively larger share of the flexibility reserve requirement and would be allocated a larger share of the flexibility reserve benefit.

[52] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 40-42.

Objections to Imputing Benefits for Within-Hour Dispatch

Q. Please describe Boise's within-hour dispatch benefit adjustment.

A. Boise reduces the regulating reserves in the pro forma period to the 30-minute level projected in the Company's 2012 Wind Integration Study (Wind Study).[53] This reduces the reserves held for the west control area by 30 percent, or 53 MW. Boise claims this to be the within-hour dispatch benefit adjustment.

Q. First, please describe the basic calculation errors in Boise's adjustment.

A. Boise's calculation removes a portion of the frequency response reserves associated with WECC standard BAL-003-1. These reserves cover frequency variation, rather than energy imbalance, and thus will not be impacted by a shorter balancing interval. Boise's calculation also overstates the reserve savings by double-counting the March reserve requirement, which is the highest of any month.

Q. Please explain the additional problem with Boise's proposed adjustment.

A. Boise's proposed within-hour dispatch benefit adjustment is fatally flawed because it repeatedly counts the same benefits that are already captured in the three categories previously described.

- Boise's within-hour dispatch adjustment is derived by using capacity held for reserves to make additional market transactions. These are the same reserves addressed in the inter-regional dispatch and flexibility reserve adjustments also proposed by Boise. By taking one result from the E3 Report and a second result using the same components from GRID, Boise has double-counted the associated benefits.

[53] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 42-43.

- The flexibility reserve savings in the E3 Report are dependent on the level of reserves required. If the Company's reserve requirement were reduced, as proposed in Boise's within-hour dispatch adjustment, the total flexibility reserve savings, and the Company's share of those savings, would also be reduced.
- The adjustment double-counts benefits because the intra-regional benefits are based on the operation of an hourly market compared to the operation of a five-minute market based on CAISO's experience in 2009.

Q. Are within-hour savings even applicable to GRID?

A. No. The GRID model does not include the costs of within-hour redispatch, and therefore within-hour savings are inapplicable to GRID. GRID is an hourly model that assumes there are no changes in loads and resources within the hour.

Q. How does the Company balance its system under current operations?

A. Under the current hourly scheduling process, the Company must finalize its balancing transactions with other market participants before the hour. Other than a short transition period in the first and last 10 minutes of the hour, those transaction volumes are fixed for the entire hour. As a result, the Company must dispatch its own resources to offset any changes in loads or variable generation across the hour. If load is increasing, the Company will need to back down its generation in the start of the hour and dispatch additional generation at the end of the hour. Because the lowest cost resources are dispatched first, lower cost resources will be backed down in the start of the hour, and higher cost resources will be dispatched up at the end of the hour. Load and variable generation vary continuously, and every hour will have both periods that are above the hourly average and periods that are below the hourly average.

Q. How would the EIM impact within-hour dispatch?

A. The EIM re-dispatches the Company's resources as well as the CAISO resources every five minutes to optimally serve the combined PacifiCorp and CAISO load, subject to the EIM transmission limits.

Q. What is the net result of within-hour EIM dispatch?

A. PacifiCorp resources that are lower cost than CAISO resources would be dispatched to a greater extent resulting in EIM transfers from PacifiCorp to CAISO, and PacifiCorp resources that are higher cost than CAISO resources would not be dispatched as much resulting in EIM transfers from CAISO to PacifiCorp.

Q. How does this net result compare to the modeled results in GRID?

A. This result mimics the result calculated by GRID. As described earlier, the GRID model already includes transactions at the COB market, which use the same transmission capacity contemplated for transfers to and from CAISO in the E3 Report. The majority of the transactions reflect system balancing decisions by the GRID model, which optimizes the dispatch of PacifiCorp generation against market transactions, much like what will occur under the EIM. Because GRID has unchanging load across each hour, it is comparable to dispatching thermal resources and market transactions across twelve identical five-minute blocks in an hour—since the load is identical, the results are identical. Because GRID is able to balance the precise load across each time period using market transactions, it already reflects the benefits of within-hour market transactions. To reflect the Company's current operations, i.e. without intra-hour market transactions, GRID would need to have fixed market transactions for the entire hour and have any variation in load or variable resources over each hour met by dispatching generation resources.

Q. What do you recommend regarding within-hour EIM dispatch benefits?

A. Boise's proposed within-hour adjustment should be rejected because it double counts, is overstated, and is intended to remove costs from GRID that were never included in the first place.

Other Objections to Imputing EIM Benefits

Q. Considering all of the non-matching aspects of the E3 Report to the pro forma NPC calculated using GRID, is it reasonable to impute EIM benefits as proposed by Boise?

A. No. As noted above, imputation of EIM benefits cannot be reconciled with the rationale underlying the WCA. In addition, given the restrictions on five-minute dynamic transfer capability, the benefits expected in the pro forma period in this case would most closely correspond to the low range of benefits in the E3 Report assuming 100 MW of transfer capability. The total benefits for the year 2017 under that scenario are $10.5 million, consisting of $7.0 million for inter-regional dispatch, $2.3 million for intra-regional dispatch, and $1.2 million for flexibility reserves. That amount would need to be further reduced to reflect a phased-in ability for the Company's generating units to bid into the EIM as compared to the same assumption in the E3 Report.

The E3 Report does not reflect matching assumptions in this rate case including a different test period, forward price curves, transmission topology, and differences in the underlying production dispatch model and associated model architecture. Furthermore, the purpose and design of the EIM is to optimize the Company's system dispatch across its entire footprint, not just the west control area. Considering these facts and other points I have made in my rebuttal testimony, I conclude that the Company's proposal to exclude the benefits, and also the costs, of EIM from this case is reasonable.

Inter-Hour Integration

Q. Please explain Boise's adjustment related to inter-hour integration of wind and load.

A. Boise argues that the new methodology for including the shape of wind generation in GRID already reflects actual hour-to-hour variability and that calculating inter-hour integration costs outside of GRID means that the Company is double-counting the inter-hour integration costs in the NPC.[54] Boise argues the same rationale applies to the hourly load forecast included in GRID, and that the inter-hour load integration costs should also be removed.

Q. How does Boise describe system balancing wind integration?

A. Boise describes system balancing wind integration costs as the system costs associated with the hour-to-hour variability in wind output.[55] Boise claims that the increase in NPC due to introducing wind variability is the same as the inter-hour integration cost added to NPC by the Company.

[54] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 47.
[55] *Id*.

Q. Do you agree that the increase in NPC due to wind variability is the same as inter-hour integration?

A. No. Boise's basic assumptions underlying this adjustment are flawed and the adjustment is meritless.

Q. Can you please further explain the cost of inter-hour wind integration?

A. Yes. The Company must commit generation resources (*i.e.*, select start-up and shutdown times for the next day), based on a forecast of load and wind generation and considering wholesale market prices, but must dispatch those resources to balance the actual load and wind conditions that occur in real time. In the Company's Wind Study, this inter-hour integration, or system balancing, cost is calculated by comparing the NPC from two studies. In the first study, the economic unit commitment is determined including the day-ahead forecast and the system is balanced around the forecast wind output. In the second study, the economic units' commitment remains based on the day-ahead forecast, but the system must balance around the actual wind output. Costs are higher in the second study because the unit commitment is optimized against wind output that is different from what actually occurs. The Wind Study determined this cost to be 36 cents (in 2012 dollars) per megawatt-hour of wind generation and this cost is added to the Company's NPC results.[56]

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[56] PacifiCorp 2013 Integrated Resource Plan, Volume II, Appendix H—Wind Integration Study, Table H.2. Available online at: www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf

Q. Is the hour-to-hour variability included in the Company's wind generation forecast the same issue as measured by the Wind Study?

A. No. The Wind Study measures the impact of committing generation resources considering a forecast of wind generation and then dispatching those resources when actual generation is different than forecast. The Company's filed GRID study uses the same wind shape to determine unit commitment and final dispatch, so the costs associated with less-than-optimal day-ahead unit commitment are not included in the GRID model. Clearly, Boise's claim that the cost of using the actual wind shape during each hour in GRID, rather than using a less volatile shape, is the same as including costs borne from committing generation resources against forecasted load and wind generation and then dispatching generation resources under actual load and wind conditions as they occur in real time is incorrect.

Q. Is it appropriate to include both inter-hour integration costs and an hourly wind shape?

A. Yes. As describe above, the Company's filed GRID study uses the same wind shape to determine unit commitment and final dispatch, so the costs associated with less-than-optimal day-ahead unit commitment are not included within the GRID model. Therefore the Company's continued application of this cost outside of the GRID model is appropriate and is in keeping with the basis for these expenses in the 2012 Wind Study.

Q. Are inter-hour load integration costs derived in the same manner as system balancing wind integration costs?

A. Yes. Both of these costs result from the unpredictable nature of load and wind on a day-ahead basis and committing generation resources against a forecast and then dispatching generation resources under actual conditions. The Wind Study accounted for the inter-hour integration costs associated with load using the same methodology as for wind, by calculating unit commitment based on the day-ahead load forecast, and system costs based on the actual load.

Q. Do costs caused by variations between day-ahead and actual wind and those caused by load impact the Company's system differently?

A. No. An increase in load and a decrease in wind generation in the same area both require additional generation or replacement market power, and both impact the level of reserves the Company is required to hold.

Q. Is this the first time the Company included inter-hour load integration charges in NPC?

A. No. In the 2010 Wind Integration Study, the reported system balancing cost for wind reflected the cost of day-ahead forecast errors for both wind and load. The costs associated with both wind and load errors were divided by the wind generation in the study resulting in a total cost averaging $0.86 per megawatt-hour of wind generation.[57] This issue was identified in stakeholder comments on the 2010 Wind Integration Study, and in the 2012 Wind Study the methodology was revised to

[57] PacifiCorp 2013 Integrated Resource Plan, Volume II, Appendix H - Wind Integration Study. Table H.2. Available online at: www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf

distinguish between wind and load, which resulted in the lower inter-hour wind integration cost of $0.36 per megawatt-hour. Because the 2010 Wind Integration Study results were used in Docket UE-111190, inter-hour costs for load have already been reflected in rates in the past.

RENEWABLE RESOURCE TRACKING MECHANISM

Q. Please summarize the Company's proposed RRTM.

A. The RRTM is designed to allow the Company to recover the costs incurred to comply with the EIA, as provided by RCW 19.285.050(2).[58] Consistent with Washington state policy, since the enactment of the EIA, the Company has added significant new wind resources in its west control area. The intermittent nature of these new wind resources created volatility in the Company's NPC that would not exist without these resources. To address this volatility, the Company proposed an RRTM that would allow a dollar-for-dollar true up of forecast to actual wind generation. The RRTM ensures that customers pay the actual costs associated with the energy they consume and eliminates barriers to further renewable energy development, in furtherance of Washington state policy.

Q. Do parties support the Company's proposed RRTM?

A. No. Parties' criticisms are similar, focusing largely on the lack of dead bands and sharing bands and the fact that the RRTM is narrowly focused on only intermittent renewable resources. In addition, even though Staff rejects the proposed RRTM, Staff proposed a PCAM as an alternative.

[58] RCW 19.285.050(2) provides that an "investor-owned utility is entitled to recover all prudently incurred costs associated with compliance with this chapter."

Q. Please respond to the Staff's proposed PCAM.

A. The Company appreciates Staff making a PCAM proposal in recognition of the fact that the Company is the only energy utility in Washington without such a mechanism. But Staff's PCAM does not address the under-recovery of renewable resource costs or negate the need for the RRTM. The Company cannot accept Staff's proposed PCAM in lieu of the RRTM because it insufficiently addresses the issues facing the Company, including the significant variability and unpredictability of renewable generation.

Q. Are the Company's proposed RRTM and a PCAM incompatible with one another?

A. Not necessarily. For example, the OPUC just opened a generic investigation into the reasonableness of treating the variable costs of renewable resources differently than other variable power costs under utility PCAMs.[59] In that case, both PacifiCorp and Portland General Electric Company are urging the OPUC to adopt an RRTM-type mechanism to operate in tandem with the companies' PCAMs.

Q. Parties recommend that the Commission reject the RRTM for lack of dead bands or sharing bands that the Commission has required for PCAMs.[60] How do you respond?

A. The RRTM is not intended to be a PCAM, although the RRTM and a PCAM can be complementary to one another. Therefore, the policies that the Commission has

[59] *See In the Matter of Portland General Elec. Co. and PacifiCorp Request for a Generic Power Cost Adjustment Mechanism Investigation*, Docket No. UM 1662, Public Utility Commission of Oregon Staff Report (Nov. 5, 2014) ("Staff recommends that the Commission open an investigation into the treatment of variable costs that are a direct result of compliance with [Oregon's RPS]."). The OPUC adopted staff's recommendation and opened the investigation at its November 12, 2014 public meeting. The OPUC staff's report is available online at: http://edocs.puc.state.or.us/efdocs/HAU/um1662hau16726.pdf.

[60] *See e.g.* Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 6-7; Responsive Testimony of Bradley Mullins, Exhibit No. BGM-1CT at 60.

announced for PCAMs, which address a much broader category of costs, should not apply to the more narrowly tailored RRTM. The RRTM focuses on those resources that were procured specifically to further Washington state energy policy and reduce greenhouse gas emissions and resources that exhibit significant variability that is entirely outside the Company's control. The lack of sharing and dead bands ensures that the RRTM advances state energy policy and promotes renewable development by allowing full cost recovery for renewable resources used to serve Washington customers.

Q. How does the RRTM further Washington state energy policy?

A. As outlined above, Washington has made a concerted effort to promote the development of renewable resources in Washington and the Pacific Northwest. Consistent with these policies, the RRTM promotes renewable development by mitigating the cost-recovery concerns that arise due to the inherent variability of many renewable resources. With the RRTM, the Company will be well positioned to continue to develop its renewable generation portfolio to provide clean, carbon-free electricity to Washington customers.

Q. Staff observes that the Commission has consistently required dead bands and sharing bands to encourage a utility to effectively manage its NPC and keep power costs low.[61] Will the lack of dead bands and sharing bands eliminate the Company's incentives to effectively manage its NPC?

A. No. The justification for dead bands and sharing bands does not apply to the renewable resources subject to the RRTM because the variability exhibited by wind resources is out of the Company's control. The Company cannot control when or to

[61] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 8.

what extent the wind will blow and therefore cannot exercise operational control over these resources to mitigate the costs incurred when the wind blows more or less than expected. Therefore, applying dead bands and sharing bands to the RRTM is not justified.

Q. Even if the Company cannot control the level of wind generation, can the Company control other aspects of its overall NPC through, for example, integrated resource planning, hedging, or dispatch of other resources to mitigate the impact of wind variability?

A. Yes, but the control the Company can exercise does not mitigate the unpredictability of wind generation. It is true that the Company can control many aspects of its overall resource portfolio and system operations to efficiently manage NPC. And it is certainly true that the Company actively and efficiently operates its system to respond to the minute-by-minute changes in wind generation as they occur. However, even the most efficient system operation cannot entirely mitigate the risks and costs associated with the variable and unpredictable nature of wind generation. This is particularly true when rates are set based on forecast wind generation that, as demonstrated in my direct testimony, varies significantly from actual wind generation.

Q. Boise claims that the Company's overall system benefits from wind generation even though it is unpredictable and variable because the wind resources provide fuel diversity to the Company's resource portfolio.[62] Do you agree?

A. Yes. The Company does not dispute that wind resources provide valuable resource diversity to the Company's portfolio and benefit Washington customers, but that is

[62] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 57-58.

not the issue that the RRTM is intended to address. The fact is that the Company has procured and will continue to procure significant wind resources specifically to comply with state energy policy. To account for the introduction of significant amounts of variable, intermittent generation, the RRTM is designed to allow the Company to recover all its prudently incurred costs—no more and no less. For this reason, the risks and benefits due to wind generation variability, caused in large part by Washington's renewable resource procurement requirements, will fall equally—and fairly—on customers and shareholders. In this way, the RRTM ensures that Washington customers receive the full benefits and pay the full costs associated with the wind generation.

Q. Staff also claims that the variation in renewable generation is "nothing more than normal market and weather variation, which the Commission does not include in PCAMs."[63] How do you respond?

A. The Company does not dispute that the Commission has previously stated that PCAMs are intended to capture extraordinary, not normal, power cost variability.[64] However, the risks associated with the Company's renewable resources are risks created by state energy policy encouraging and requiring the development of renewable resources. Therefore, it is reasonable for Washington customers to assume the risk and costs created by Washington policy-makers.

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[63] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 7.
[64] *See, e.g. Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket No. UE-130043, Order 05 ¶ 172 (Dec. 4, 2013).

Q. Staff claims that the majority of the variation the Company claims is due to wind generation is actually due to variation in market prices.[65] Boise makes a similar point.[66] How do you respond?

A. The RRTM must account for market variability because that variability is an integral component of the cost variability associated with intermittent wind resources. The RRTM calculates the difference between the value of wind modeled in the Company's forecast NPC and the actual value of wind based on actual generation and actual market conditions. There is nothing unreasonable about factoring in market price changes because that is the most accurate way to calculate the NPC impact of variations in wind generation. And even if market variability is a component of the overall RRTM calculation, market prices, like wind generation, are outside the Company's control. Indeed, Staff has previously testified that the "Company has no control of either the sales prices or purchase prices related to economy market energy transactions it needs to make in order to address hydro-generation variability or short-term changes in customer load."[67] Again, the RRTM is designed to ensure that customers pay the cost of the generation used to serve them, no more and no less, and therefore it must accurately value wind generation to do so.

Q. Boise claims that the Company's wind generation variability from year to year is not great enough to warrant the RRTM and that wind variability is, in fact, less than hydro variability.[68] How do you respond?

A. Boise's analysis is incomplete because the RRTM is intended to address variability

[65] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 10.
[66] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 58.
[67] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket No. UE-061546, Testimony of Alan P. Buckley, Exhibit No. APB-1T at 33:1-3 (Feb. 16, 2007).
[68] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 54-55.

from forecasts to actuals, not variability from year-to-year. As I demonstrated in my direct testimony, the variability of forecast to actual generation is significant.[69]

In addition, the comparison of wind to hydro variability misses the mark because wind is more unpredictable than hydro. While it is certainly difficult to forecast hydro generation over the course of a year, there is predictability to the shape of hydro seasonally that is not present with wind. Wind generation can change from minute to minute, and because the majority of the Company's wind resources in the west control area are located in the same general area, there is little geographic diversity to mitigate changing wind conditions.

Q. Has Boise previously acknowledged the difficulty in forecasting wind generation?

A. Yes. In the Company's last general rate case, Docket UE-130043, Boise's NPC witness Mr. Michael Deen testified that, "Forecasting normalized annual generation for large-scale wind projects in the United States is very much a science still in development . . . it is clear that wind power resources can display a high level of variability in inter-annual generation."[70]

Q. Staff and Boise claim that the RRTM is too narrow and should be rejected because there is uncertainty associated with all aspects of the Company's NPC and it is unreasonable to single out only renewable resources.[71] Please respond.

A. I agree that there is uncertainty and variability related to many aspects of the Company's NPC. However, the difficulty of accurately forecasting wind generation

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[69] Direct Testimony of Gregory N. Duvall, Exhibit No. GND-1CT at 42 Table 7.

[70] *Wash. Utils. & Transp. Comm'n v. PacifiCorp,* Docket No. UE-130043, Responsive Testimony of Michael C. Deen on behalf of Boise White Paper, LLC, Exhibit No. MCD-1CT at 9:4-6 (June 21, 2013).

[71] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 12; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 55.

is greater than the difficulty of forecasting many other aspects of the Company's NPC. And, unlike many other variables impacting the Company's NPC, the wind variability is a direct result of Washington laws and policies encouraging and requiring the Company to procure specific types of resources.

I would also note that in past dockets, ICNU proposed a PCAM that would address only hydro variability, much in the same way that the RRTM addresses only renewable variability.[72] Although ICNU's hydro-only PCAM was not adopted by the Commission, it supports the Company's view that a cost adjustment mechanism that is narrowly focused on particular resources is reasonable.

Q. Boise also quotes a brief filed by the Company in Oregon claiming that the Company cannot isolate the impact of wind generation from its overall NPC.[73] Does Boise's testimony accurately portray the Company's argument in the Oregon proceeding?

A. No. Boise failed to provide the full excerpt from the record in Oregon. Specifically, in the Oregon proceeding, I testified that the Company could not "isolate and quantify the exact NPC impacts associated with the renewable generation."[74] I then testified that the risks associated with increased renewable generation resulting from RPS obligations can be measured "based on variances in wind output and market prices actually experienced,"[75] which is the same methodology the Company proposed for its RRTM.

[72] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket No. UE-061546, Order 08 ¶ 62 (June 21, 2007) (". . . ICNU recommends that the Commission approve a PCAM that is focused narrowly on variability of hydro-generation . . ."; *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket No. UE-061546, Direct Testimony of Randall J. Falkenberg, Exhibit No. RJF-1T at 69-72 (Feb. 16, 2007).
[73] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 56.
[74] *In re PacifiCorp*, OPUC Docket No. UE 246, Exhibit PAC/2200, Duvall/2 (Sept. 5, 2012).
[75] *Id.*

Q. Parties also claim that the Company's proposed RRTM could allow it to surcharge customers for variations in wind generation even when the Company's overall NPC were less than forecast.[76] How do you respond?

A. While this concern seems mostly theoretical given the Company's consistent under-recovery of NPC in Washington, the Company is willing to modify its RRTM to cap the potential customer charges to ensure that the Company recovers no more than its actual NPC in any particular year. In this way, the Company could never recover more than its actual NPC. This cap makes the RRTM more restrictive than Staff's proposed PCAM, which would allow the Company to recover more than its actual NPC after application of the sharing and dead bands.

LOW HYDRO DEFERRAL

Q. Please describe the Company's deferred accounting request related to low hydro conditions.

A. The Company filed an application with the Commission on January 17, 2014, seeking authorization to defer for later ratemaking treatment costs associated with significant variances in actual hydro generation and hydro generation in rates due to abnormal weather conditions and water availability.

Q. Do the other parties support the Company's low hydro deferral?

A. No. Staff calculates the hydro generation variance for 2014 as within 2.9 percent of hydro generation included in rates and claims this is within an acceptable range; however an "acceptable range" is left undefined.[77] Public Counsel argues that it is not appropriate to defer a select portion of NPC variances between rate cases.[78] Boise

[76] *See e.g.* Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 39.

rejects the low hydro deferral, arguing that hydro conditions are "about normal" and the deferral is one sided.[79]

Q. How do you respond?

A. Hydro resources provide customers with the benefit of a zero-net-power-cost generating resource. When actual hydro generation is less than the hydro generation in rates it must be replaced by either purchasing power or increased thermal generation. Due to abnormal hydro conditions beginning in late 2013 and continuing in 2014, the Company has been incurring replacement power costs caused by the variance in hydro generation. Without the deferral, the Company would absorb the costs resulting from unpredictable weather outside of the Company's control.

Q. How do you respond to Staff's comment that "[the Company] is compensated for "abnormal" hydro variances in net power costs and needs no special accounting treatment"?

A. Staff's comment is misguided as it incorrectly accounts for the development of hydro generation levels in the Company's pro forma NPC. For the purpose of setting rates, the Company uses a single-year of median-hydro generation levels. Other Washington utilities set rates based on the average costs in 40 or more historical water years, which reflects the costs and benefits of the variance in hydro generation in the historical data set. However, the Company's hydro generation forecast, based on a median water year, does not account for any of the costs or benefits associated with year-to-year variability.

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[77] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 16-18.
[78] Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 42-45.
[79] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 67-68.

Q. Have you updated the costs of replacement power associated with low hydro conditions?

A. Yes. Attached as Confidential Exhibit No. GND-8C is the Company's fifth supplement response to Public Counsel Data Request 2 in the low hydro deferral docket (Docket UE-140094). The response provides actual excess NPC associated with low hydro conditions through September 2014, as well as an updated projection through December 2014. Based on this updated data, hydro generation for all of 2014 is approximately 7.6 percent lower than the amount in rates.[80] Accordingly, the Company requests amortization of approximately $2.4 million in Washington-allocated excess NPC. The Company's deferral request is also discussed in the rebuttal testimony of Ms. Siores.

THERMAL OUTAGE MODELING

Q. What does Boise recommend regarding certain outages at Chehalis and Colstrip Unit 4?

A. Boise claims that two outage events, one at Chehalis and one at Colstrip Unit 4, were the result of imprudent operations and recommends disallowance of the related costs. For Chehalis, Boise recommends removing the outage from the four-year historical average outage rate used to determine pro forma NPC. For Colstrip Unit 4, Boise recommends the Commission reject the Company's application for deferred accounting and recovery of related costs.

[80] The 2.9 percent calculated by Mr. Gomez is based on actual hydro generation through August 2014 and excludes the first 17 days of January, consistent with the Company's deferred accounting application. Including actual hydro generation through September and an updated balance of year forecast increases the 2.9 percent to 5.3 percent.

Q. How does the Company respond to the allegations that the outages were the result of imprudent operations?

A. Boise's allegations are incorrect. In his rebuttal testimony, Mr. Dana M. Ralston provides evidence demonstrating the outages at Chehalis and Colstrip Unit 4 occurred despite prudent plant operation.

Q. What are the implications for cost recovery if the Chehalis outage is removed from the average?

A, The Company uses a four-year historical average outage rate at each plant to determine the plant availability during the pro forma period used to determine NPC in rates. If outage events such as those at Chehalis and Colstrip Unit 4 are not included in the historical average, the Company will have no way to recover the cost of such events without some kind of deferral mechanism, even when the outages are determined to be prudent.

Q. How have you addressed this situation for the Colstrip outage?

A. Due to the anticipated length of the Colstrip outage, the Company filed its request for deferred accounting treatment of the replacement power costs. In conjunction with deferred accounting treatment, the average outage rate used in the general rate case for Colstrip Unit 4 is set at a normalized, lower level that does not reflect the outage in question.

Q. What about the Chehalis outage?

A. In this case, if the Chehalis outage is removed from the average outage calculation, the Company will not recover the net power cost impact of the outage.

Q. Has Staff previously agreed that deferred accounting was an appropriate option if prudent forced outages are normalized out of the forced outage rate?

A. Yes. As I described in my direct testimony, in Docket UE-100749, the Commission approved an adjustment to limit the forced outage rate to eight percent for Colstrip Unit 4. In that case, the Company included a seven-month outage at the plant during 2009 in the 48-month historical average, increasing the calculated outage rate used in GRID. The Commission determined that the extended outage should not be included in the historical average because the result was less predictive of what may occur in the future. In that case, Staff recognized that reducing the outage rate would limit cost recovery for the incident, and Staff supported the idea of using deferred accounting to achieve recovery.[81] Ms. Siores provides additional testimony on the Colstrip deferred accounting request in her rebuttal testimony.

Q. If deferred accounting is not approved for the Colstrip Unit 4 outage, should the Company's forced outage rate be adjusted to include this outage?

A. Yes. In the current filing, the 48-month historical outage rate for Colstrip Unit 4 is influenced by the extended forced outage in 2013; however, the Company limited the outage rate used for NPC to eight percent. If the Company's request for deferred accounting is rejected, the historical outage rate for Colstrip Unit 4 should be increased to reflect actual plant operations.

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[81] *Wash. Utils. & Transp. Comm'n v. PacifiCorp,* Docket No. UE-100749, Buckley, Transcript 584:3-10 (Jan. 26, 2011) ("For the case of PacifiCorp, which does not have any kind of power cost mechanism, then I'm proposing it could be done through an accounting petition or some other method, which is really very similar if not the same as what we've already done with—I believe it was the kind of anomalous hydro generation outages back during the energy crisis there was some deferred power costs that the Company filed for recovery of.").

ACCEPTED ADJUSTMENT

Q. Does the Company accept Boise's adjustment related to network integration transmission service, or NITS, from BPA?

A. Yes, in part. The Company accepts in concept Boise's adjustment to reduce wheeling expenses related to BPA NITS. But Boise's proposed calculations to determine BPA NITS expense for the forecast period are flawed and overstate the required adjustment.

Q. What are the BPA NITS wheeling expenses?

A. Some of the Company's west control area retail loads are served using BPA's transmission system, rather than exclusively using Company-owned transmission assets. BPA charges for NITS based on a customer's load during the hour of BPA's transmission system peak in each month. The rates charged by BPA for this service were last updated in October 2013 as part of BPA's most recent rate case.

Q. How did the Company calculate BPA NITS expense in its initial filing?

A. The Company applied the current BPA rates to its forecasted load at the time of its non-coincident peak during the pro forma period for each load pocket served with BPA NITS.

Q. Please describe Boise's proposed adjustment related to BPA NITS expense.

A. Boise's adjustment calculates the Company's BPA NITS expense based on the average of the Company's forecasted BPA NITS loads in four hours per month. The hours selected match the day of the month and the hour from the actual BPA transmission system peak from each of the last four years.

Q. Do you agree with Boise's proposed method to approximate BPA NITS expense?

A. No. Boise's proposed adjustment is an overly complicated attempt to forecast the time of BPA transmission system peak during the rate-effective period. There are two primary flaws in Boise's proposed method. First, under Boise's methodology, 23 percent of the BPA system peaks in the forecast period occur on Sunday. In the last 48 months, the BPA system peak only occurred on a Sunday once, or about two percent of the time.

The second flaw with Boise's methodology is that it ignores weather, which is the biggest driver of peak loads. The Company's pro forma NPC is based on normal weather, with a shape representing the range of expected temperatures in each month. The coldest days in the winter months and the hottest days in the summer months have the highest loads. The BPA system and the Company's BPA NITS loads are both located in the Pacific Northwest and experience similar weather. This weather varies from year-to-year, thus the day of the peak does not provide insight into the timing of the BPA system peak in other periods. Because the day of the month has little to do with the weather, Boise's method is effectively basing the costs on loads from random days in the forecast period.

Q. Is the impact of Boise's adjustment reasonable?

A. No. Boise's proposed BPA NITS wheeling expense forecast is lower than the 2013 actual levels. This result is particularly unreasonable considering that in October 2013 BPA implemented a rate increase, raising the NITS rates by 9.3 percent.

Q. Please describe the adjustment the Company incorporated in its rebuttal NPC update.

A. The historical BPA NITS wheeling expenses for 2013 reflect nine months of BPA's old rates in January through September, and three months of the current rates which took effect in October 2013. The Company's rebuttal update adjusts the historical expenses for January through September to account for the change from BPA's old rates to its current rates and includes expenses for October through December at the actual levels.

Q. Are there any other factors that could contribute to higher BPA NITS expense in the pro forma period?

A. Yes. BPA's current rates are in effect through September 2015, six months into the pro forma period in this case. BPA has projected that NITS rates may increase by 9.7 percent in October 2015.[82] Because the Company's request in this case does not include any future BPA rate increases, there is a significant potential for higher BPA NITS expense.

Q. How should the BPA NITS expense be calculated for the pro forma period?

A. Adjusting the historical expense for the BPA rate change which occurred on October 1, 2013, is straightforward and reasonably captures the actual historical relationship between the Company's BPA NITS loads and BPA's transmission system peak. This adjustment results in a reduction to west control area NPC of $0.8 million.

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[82] BPA Presentation: *Building the Framework for the 2014 Integrated Program Review*. Available online at: www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2014IPRDocuments/Building%20the%20Framework%20for%20the%20IPR%201.8.2014.pdf, accessed November 10, 2014.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit No. GND-5
Docket UE-140762 *et al.*
Witness: Gregory N. Duvall

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF GREGORY N. DUVALL

Rebuttal Net Power Cost Analysis

November 2014

PacifiCorp

WAGRC March16 NPC Rebuttal Study

Net Power Cost Analysis

12 months ended March 2016	04/15-03/16	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills s27013/s28160	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Wind s42818	-	-	-	-	-	-	-	-	-	-	-	-	-
East Area Sales (WCA Sale)	48,376,416	5,991,771	6,204,261	7,922,832	9,547,946	7,733,749	2,128,716	3,751,458	121,139	-	-	1,168,967	3,805,579
Hurricane Sale s393046	-	-	-	-	-	-	-	-	-	-	-	-	-
LADWP (IPP Layoff)	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenue	118,434	7,536	8,983	8,589	13,661	13,336	11,296	10,083	7,876	8,745	7,889	8,154	12,287
NVE s811499	-	-	-	-	-	-	-	-	-	-	-	-	-
Pacific Gas & Electric s524491	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCO s100035	-	-	-	-	-	-	-	-	-	-	-	-	-
Salt River Project s322940	-	-	-	-	-	-	-	-	-	-	-	-	-
SCE s513948	-	-	-	-	-	-	-	-	-	-	-	-	-
SDG&E s513949	-	-	-	-	-	-	-	-	-	-	-	-	-
Shell Sale 2013-2014	-	-	-	-	-	-	-	-	-	-	-	-	-
SMUD s24296	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	48,494,850	5,999,307	6,213,244	7,931,421	9,561,607	7,747,085	2,140,012	3,761,541	129,015	8,745	7,889	1,177,121	3,817,865
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	364,294	30,358	30,358	30,358	30,358	30,358	30,358	30,358	30,358	30,358	30,358	30,358	30,358
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	364,294	30,358	30,358	30,358	30,358	30,358	30,358	30,358	30,358	30,358	30,358	30,358	30,358
System Balancing Sales													
COB	36,691,212	1,870,863	1,580,322	1,373,306	4,405,538	4,109,047	3,934,276	2,540,044	3,008,446	3,579,228	3,923,078	3,440,284	2,926,780
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	11,457,160	298,000	80,290	22,029	1,368,688	1,661,440	1,939,428	1,623,936	909,392	712,990	917,673	955,833	967,461
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	11,890	3,134	464	122	-	39	2,588	5,495	-	-	-	-	48
Total System Balancing Sales	48,160,262	2,171,997	1,661,076	1,395,457	5,774,226	5,770,526	5,876,292	4,169,475	3,917,838	4,292,218	4,840,751	4,396,117	3,894,288
Total Special Sales For Resale	97,019,406	8,201,662	7,904,678	9,357,235	15,366,190	13,547,968	8,046,662	7,961,373	4,077,211	4,331,321	4,878,998	5,603,596	7,742,511

PacifiCorp

WAGRC March16 NPC Rebuttal Study

Net Power Cost Analysis

12 months ended March 2016	04/15-03/16	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental p27875	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Reserve Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Combine Hills Wind p160595	5,225,445	403,458	375,039	451,979	433,241	429,645	409,479	439,678	490,452	357,384	507,157	341,533	586,400
Deseret Purchase p194277	-	-	-	-	-	-	-	-	-	-	-	-	-
Douglas PUD Settlement p38185	2,224,402	255,408	327,131	354,008	307,832	238,498	106,296	98,796	98,344	99,877	99,317	93,907	144,986
Gemstate p99489	-	-	-	-	-	-	-	-	-	-	-	-	-
Georgia-Pacific Camas	4,573,171	498,891	515,521	498,891	515,521	515,521	498,891	515,521	498,891	515,521	-	-	-
Hermiston Purchase p99563	80,517,122	6,178,548	4,352,973	3,653,120	7,150,205	7,441,624	6,875,359	7,736,006	7,471,570	7,762,713	7,710,006	7,138,687	7,046,310
Hurricane Purchase p393045	-	-	-	-	-	-	-	-	-	-	-	-	-
IPP Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp p229846	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves p510378	-	-	-	-	-	-	-	-	-	-	-	-	-
Nucor p346856	-	-	-	-	-	-	-	-	-	-	-	-	-
P4 Production p137215/p145258	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove p83984	235,042	19,587	19,587	19,587	19,587	19,587	19,587	19,587	19,587	19,587	19,587	19,587	19,587
Rock River Wind p100371	-	-	-	-	-	-	-	-	-	-	-	-	-
Small Purchases east	-	-	-	-	-	-	-	-	-	-	-	-	-
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind p460457	-	-	-	-	-	-	-	-	-	-	-	-	-
Top of the World Wind p522807	-	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State Purchase p27057	-	-	-	-	-	-	-	-	-	-	-	-	-
West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek Wind p244520	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Term Firm Purchases Total	92,775,181	7,355,892	5,590,250	4,977,585	8,426,385	8,644,875	7,909,613	8,809,589	8,578,845	8,755,082	8,336,068	7,593,713	7,797,283
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

PacifiCorp

WAGRC March16 NPC Rebuttal Study

Net Power Cost Analysis

12 months ended March 2016	04/15-03/16	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16
Qualifying Facilities													
QF California	6,984,613	1,013,415	1,028,361	797,638	379,393	282,261	261,584	263,742	292,211	436,307	655,471	754,090	820,140
QF Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
QF Oregon	26,514,531	2,688,713	2,782,984	2,492,022	2,169,944	2,027,320	2,070,553	1,851,778	1,624,967	2,033,951	2,220,421	2,136,161	2,415,716
QF Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
QF Washington	579,500	31,352	47,095	68,317	84,596	89,107	76,402	43,365	27,078	27,022	28,403	28,399	28,364
QF Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass One QF	14,394,882	718,405	723,393	718,402	1,424,771	1,429,423	1,404,789	1,440,558	1,181,511	1,268,761	1,367,290	1,323,885	1,393,695
Butter Creek Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Champlin Blue Mtn Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind p499335 QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-Gen II	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP p316701 QF	185,544	12,000	20,907	17,726	18,732	18,873	16,133	25,051	16,533	7,716	12,436	9,164	10,273
Co-Gen II p349170 QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Evergreen BioPower p351030 QF	2,565,401	141,532	157,092	168,446	270,667	277,225	255,464	282,103	211,801	218,757	200,375	201,385	180,553
ExxonMobil p255042 QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Ridge Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Ridge Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mariah Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Orem Family Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
North Point Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
OM Power I Geothermal QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon Wind Farm QF	11,866,536	1,170,368	1,187,991	1,389,764	1,420,408	1,070,425	881,619	901,747	1,036,952	356,535	688,544	787,034	975,150
Pioneer Wind Park I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Pioneer Wind Park II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Power County North Wind QF p5756	-	-	-	-	-	-	-	-	-	-	-	-	-
Power County South Wind QF p5756	-	-	-	-	-	-	-	-	-	-	-	-	-
Roseburg Dillard QF	1,008,864	46,634	28,145	32,491	148,637	112,036	86,563	37,705	84,421	106,072	133,139	128,296	64,724
SF Phosphates	-	-	-	-	-	-	-	-	-	-	-	-	-
Spanish Fork Wind 2 p311681 QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Sunnyside p83997/p59965 QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Tesoro QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Threemile Canyon Wind QF p500139	2,101,491	167,021	212,401	199,278	177,403	174,888	165,712	193,399	149,917	156,781	152,602	169,399	182,689
US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Qualifying Facilities Total	66,201,363	5,989,440	6,188,370	5,884,084	6,094,552	5,481,557	5,218,820	5,039,448	4,625,391	4,611,903	5,458,682	5,537,814	6,071,302
Mid-Columbia Contracts													
Douglas - Wells p60828	3,686,109	304,430	304,430	304,430	304,430	304,430	309,137	309,137	309,137	309,137	309,137	309,137	309,137
Grant Reasonable	(5,542,336)	(444,608)	(444,608)	(444,608)	(444,608)	(444,608)	(444,608)	(444,608)	(444,608)	(444,608)	(513,621)	(513,621)	(513,621)
Grant Surplus p258951	2,008,900	166,609	166,609	166,609	166,609	166,609	166,609	166,609	166,609	166,609	169,805	169,805	169,805
Mid-Columbia Contracts Total	152,673	26,432	26,432	26,432	26,432	26,432	31,138	31,138	31,138	31,138	(34,679)	(34,679)	(34,679)
Total Long Term Firm Purchases	159,129,217	13,371,764	11,805,052	10,888,101	14,547,369	14,152,864	13,159,570	13,880,175	13,235,373	13,398,123	13,760,071	13,096,848	13,833,907

PacifiCorp

WAGRC March16 NPC Rebuttal Study

Net Power Cost Analysis

12 months ended March 2016	04/15-03/16	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16
Storage & Exchange													
APS Exchange p58118/s58119	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind p63507	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind p79207	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho p64885/p83975/p647	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift p65787	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I p63508/p63510	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange p340325	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCO FC III p63362/s63361	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange p66276	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line p105228	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Short Term Firm Purchases													
Mid Columbia	3,856,780	3,078,100	-	-	-	-	-	778,680	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	3,856,780	3,078,100	-	-	-	-	-	778,680	-	-	-	-	-
System Balancing Purchases													
COB	5,132,444	315,360	533,362	931,014	396,767	18,112	244,464	335,755	262,311	804,883	699,715	88,591	502,111
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	72,747,131	6,360,737	11,654,269	12,327,824	9,170,018	8,029,761	2,052,926	2,857,581	2,913,971	4,124,417	3,004,217	4,033,712	6,217,701
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	161,621	22,884	10,749	25,791	22,338	-	-	-	-	78,713	-	-	1,147
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Purchases	78,041,196	6,698,981	12,198,380	13,284,629	9,589,123	8,047,872	2,297,390	3,193,336	3,176,281	5,008,012	3,703,931	4,122,303	6,720,958
Total Purchased Power & Net Inte	241,027,193	23,148,844	24,003,432	24,172,730	24,136,491	22,200,736	15,456,960	17,852,191	16,411,654	18,406,136	17,464,002	17,219,151	20,554,865

PacifiCorp

WAGRC March16 NPC Rebuttal Study

Net Power Cost Analysis

12 months ended March 2016	04/15-03/16	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16
Wheeling & U. of F. Expense													
Firm Wheeling	108,922,013	8,750,983	8,925,435	9,099,298	9,417,351	8,900,472	8,998,228	9,109,000	9,169,416	9,078,003	9,224,523	9,124,175	9,125,129
ST Firm & Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Wheeling & U. of F. Expense	108,922,013	8,750,983	8,925,435	9,099,298	9,417,351	8,900,472	8,998,228	9,109,000	9,169,416	9,078,003	9,224,523	9,124,175	9,125,129
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	-	-	-	-	-	-	-	-	-	-	-	-	-
Colstrip	8,308,649	702,891	722,024	439,968	726,070	726,752	703,080	726,751	702,739	726,854	726,262	679,031	726,228
Craig	-	-	-	-	-	-	-	-	-	-	-	-	-
Dave Johnston	-	-	-	-	-	-	-	-	-	-	-	-	-
Hayden	-	-	-	-	-	-	-	-	-	-	-	-	-
Hunter	-	-	-	-	-	-	-	-	-	-	-	-	-
Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-
Jim Bridger	239,012,112	17,336,807	15,976,421	17,772,739	22,343,501	21,781,091	20,856,190	22,040,970	21,020,768	21,258,365	20,349,887	19,743,043	18,532,329
Naughton	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyodak	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Coal Fuel Burn Expense	247,320,762	18,039,698	16,698,445	18,212,707	23,069,571	22,507,843	21,559,271	22,767,721	21,723,507	21,985,219	21,076,149	20,422,074	19,258,557
Gas Fuel Burn Expense													
Chehalis	37,956,490	209,333	-	-	5,746,964	7,240,379	4,945,092	3,745,535	2,066,072	4,617,492	4,789,780	3,752,804	843,038
Currant Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Gadsby	-	-	-	-	-	-	-	-	-	-	-	-	-
Gadsby CT	-	-	-	-	-	-	-	-	-	-	-	-	-
Hermiston	36,286,355	2,521,981	737,155	65,384	3,458,221	3,740,879	3,204,635	4,031,469	3,748,469	4,026,914	3,977,082	3,446,600	3,327,568
Lake Side 1	-	-	-	-	-	-	-	-	-	-	-	-	-
Lake Side II	-	-	-	-	-	-	-	-	-	-	-	-	-
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	74,242,845	2,731,314	737,155	65,384	9,205,185	10,981,258	8,149,726	7,777,004	5,814,541	8,644,406	8,766,862	7,199,404	4,170,606
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	(385,200)	-	-	-	-	-	-	-	(62,550)	(113,925)	(98,735)	(59,305)	(50,685)
Clay Basin Gas Storage	-	-	-	-	-	-	-	-	-	-	-	-	-
Pipeline Reservation Fees	17,513,624	1,440,155	1,480,346	1,440,155	1,480,346	1,480,346	1,440,155	1,480,346	1,440,155	1,480,346	1,480,346	1,390,584	1,480,346
Total Gas Fuel Burn Expense	91,371,270	4,171,469	2,217,501	1,505,539	10,685,531	12,461,604	9,589,881	9,257,350	7,192,146	10,010,826	10,148,472	8,530,683	5,600,267
Other Generation													
Blundell	-	-	-	-	-	-	-	-	-	-	-	-	-
Integration Charge	1,101,940	89,914	92,762	97,871	98,573	91,935	82,248	86,808	89,556	84,784	94,453	86,219	106,816
Total Other Generation	1,101,940	89,914	92,762	97,871	98,573	91,935	82,248	86,808	89,556	84,784	94,453	86,219	106,816
Net Power Cost	**592,723,771**	45,999,246	44,032,896	43,730,910	52,041,328	52,614,622	47,639,926	51,111,697	50,509,068	55,233,647	53,128,602	49,778,707	46,903,123
Net Power Cost/Net System Load	**29.61**	**29.64**	**28.55**	**28.49**	**30.34**	**31.04**	**30.86**	**32.36**	**30.01**	**29.10**	**27.98**	**29.43**	**27.84**

Exhibit No. GND-6
Docket UE-140762 *et al.*
Witness: Gregory N. Duvall

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

<table>
<tr><td>WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY,

Respondent.</td><td>DOCKETS UE-140762 and UE-140617 (consolidated)</td></tr>
<tr><td>In the Matter of the Petition of

PACIFIC POWER & LIGHT COMPANY,

For an Order Approving Deferral of Costs Related to Colstrip Outage.</td><td>DOCKET UE-131384 (consolidated)</td></tr>
<tr><td>In the Matter of the Petition of

PACIFIC POWER & LIGHT COMPANY,

For an Order Approving Deferral of Costs Related to Declining Hydro Generation.</td><td>DOCKET UE-140094 (consolidated)</td></tr>
</table>

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF GREGORY N. DUVALL

Rebuttal Update Summary

November 2014

Study	NPC	Delta	Source & Notes
WAGRC March16 _NPC Direct Filing	568,782,271	n/a	Direct Filing
Corrections (One-offs from Direct)			
C01 WAGRC March16 _NPC (Indexed QF pricing)	568,779,543	(2,729)	
Total Corrections			
Rebuttal Adjustment (One-offs from Direct)			
R01 WAGRC March16 _NPC (BPA NITS Peak)	567,945,115	(837,156)	
Total Rebuttal Changes			
Updates (One-offs from Direct)			
U01 WAGRC March16 NPC (Chehalis Lateral)	568,724,095	(58,176)	
U02 WAGRC March16 NPC (PGE Cove)	568,694,195	(88,077)	
U03 WAGRC March16 NPC (MidC Contracts)	568,961,502	179,231	
U04 WAGRC March16 _NPC (Coal Cost)	593,168,942	24,386,670	
U05 WAGRC March16 _NPC (Small QF Updates)	568,140,633	(641,638)	
U06 WAGRC March16 _NPC (1409 OFPC STF)	570,858,471	2,076,200	
U07 WAGRC March16 _NPC (Goodnoe Wheeling Credit)	568,374,871	(407,400)	
Total Updates		25,446,810	
Total Corrections and Updates			
Balancing		(665,426)	
WAGRC March16 NPC Rebuttal Study	592,723,771	23,941,500	Rebuttal Filing
Testimony One-offs		vs Rebuttal	
ORCA QF Load Decrement	527,101,908	(65,621,863)	
ORCA QF Repricing	583,799,591	(8,924,180)	
Exclude ORCA QFs	550,701,665	(42,022,106)	

Exhibit No. GND-7
Docket UE-140762 *et al.*
Witness: Gregory N. Duvall

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF GREGORY N. DUVALL

PacifiCorp EIM Participating Resources

November 2014

PacifiCorp EIM Participating Resources

Renewable Resource Name	Resource Type	State Renewable Portfolio Standard Eligibility
EAST		
Dave Johnston 3	Coal	NA
Dave Johnston 4	Coal	NA
Naughton 1	Coal	NA
Naughton 2	Coal	NA
Naughton 3	Coal	NA
Huntington 1	Coal	NA
Huntington 2	Coal	NA
Hunter 3	Coal	NA
Currant Creek	Gas	NA
Lake Side 1	Gas	NA
Lake Side 2	Gas	NA
Dunlap	Wind	Oregon and California qualifying resource
Glenrock / Rolling Hills*	Wind	Glenrock: Oregon and California qualifying resource *Rolling Hills: California qualifying resource; not eligible for Oregon
High Plains / McFadden Ridge	Wind	Oregon and California qualifying resources
Seven Mile Hill	Wind	Oregon and California qualifying resource
WEST		
Hermiston	Gas	NA
Chehalis	Gas	NA
Leaning Juniper	Wind	Oregon, Washington and California qualifying resource
Goodnoe Hills	Wind	Oregon, Washington and California qualifying resource
Swift 1	Hydro	Pending LIHI certification (currently not a qualifying resource)
Yale	Hydro	Pending LIHI certification (currently not a qualifying resource)

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

REDACTED EXHIBIT OF GREGORY N. DUVALL

Low Hydro Deferral

November 2014

UE-140094 / Pacific Power & Light Company
November 4, 2014
PC Data Request 2 – 5th Supplemental

PC Data Request 2

Please provide the forecasted excess net power costs associated with declines in hydro generation on a monthly basis for 2014, as well as actual excess net power costs to-date for 2014. Please provide monthly updates as they are available. Please provide this data on a total-Company and Washington allocated basis.

5th Supplemental Response to PC Data Request 2

As a supplement to the Company's previous responses to Public Counsel Data Request 2, the Company provides the following update:

Please refer to Confidential Attachment PC 2 5th Supplemental, which provides the excess net power costs (NPC) associated with hydro generation, updated through September 2014. Note: the Company has made a minor modification to the hydro deferral interest calculation to match the monthly accrual methodology used in the Company's 2014 general rate case filing (Docket UE-140762). The Company has also updated the balance-of-year hydro generation forecast for October 2014 through December 2014. A redacted version is also provided.

Confidential information is provided subject to the terms and conditions of the protective order in Docket UE-140762.

PREPARER: Dan MacNeil

SPONSOR: To Be Determined

Month	Date	Actual/Forecast Hydro Generation MWh	In rates Hydro Generation MWh	Hydro Variance Generation MWh	Replacement Power Cost Expense $	WA-Allocated Replacement Power Expense $	WA-Allocated Interest Expense $	WA-Allocated Cumulative Balance Expense $	Source
1	1/1/2014	[redacted]				*Deferral begins 1/18/14*			Actual
1	1/18/2014	[redacted]							Actual
2	2/1/2014								Actual
3	3/1/2014								Actual
4	4/1/2014								Actual
5	5/1/2014								Actual
6	6/1/2014								Actual
7	7/1/2014								Actual
8	8/1/2014								Actual
9	9/1/2014								Actual
10	10/1/2014								Forecast
11	11/1/2014								Forecast
12	12/1/2014								Forecast
1	1/1/2015								
2	2/1/2015								
3	3/1/2015								
4	4/1/2015								
	Total				[redacted]				
	WA-Allocated								

WA-Allocation Factor	CAGW	WACC
UE-130043	22.534%	7.36%

Confidential Per Protective Order in UTC Docket UE-140762
Exhibit No. CAC-1CT
Docket UE-140762 *et al.*
Witness: Cindy A. Crane

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

REDACTED REBUTTAL TESTIMONY OF CINDY A. CRANE

November 2014

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Q. Please state your name, business address, and present position with Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp.

A. My name is Cindy A. Crane. My business address is 201 South Main Street, Suite 2300, Salt Lake City, Utah 84111. My position is President and Chief Executive Officer (CEO), Rocky Mountain Power.

Q. Did you previously submit direct testimony in this case on behalf of Pacific Power?

A. No. The Company's direct testimony on its pro forma coal expense was included in the testimony of Mr. Gregory N. Duvall. I will be the Company's witness on coal expense in this case, and I am adopting that portion of Mr. Duvall's direct testimony.

QUALIFICATIONS

Q. Briefly describe your professional experience.

A. I joined PacifiCorp in 1990 and have held positions of increasing responsibility, including Director of Business Systems Integration, Managing Director of Business Planning and Strategic Analysis, and Vice President of Strategy and Division Services. My responsibilities included the management and development of PacifiCorp's ten-year business plan, assessing individual business strategies for PacifiCorp Energy, managing the construction of the Company's Wyoming wind plants, and assessing the feasibility of a nuclear power plant. In March 2009, I was appointed to Vice President of Interwest Mining Company and Fuel Resources. In this position, I was responsible for the operations of Energy West Mining Company and Bridger Coal Company, as well as overall coal supply acquisition and fuel management for PacifiCorp's coal-fired generating plants. On November 1, 2014, I was appointed President and CEO, Rocky Mountain Power.

PURPOSE AND SUMMARY

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony describes the pro forma coal expense changes in the Company's rebuttal net power costs (NPC). The changes in coal expense described in this testimony reflect updated fuel prices and volumes associated with the coal supplied by the Black Butte mine (Black Butte) and the Bridger Coal Company (BCC) to fuel the Jim Bridger coal-fired generating plant (Bridger plant). My testimony also provides updated coal supply prices for the Colstrip coal-fired generating plant (Colstrip plant).

Q. Please summarize your testimony regarding changes to pro forma coal expense?

A. Pro forma coal expense in the Company's rebuttal NPC increased by approximately $25.0 million on a west control area basis; $24.4 million is associated with higher coal prices and $0.6 million is associated with increased volumes. Approximately [redacted] million of the price-related increase is related to the Bridger plant and results from updated contract prices and volumes for Black Butte coal and reduced volumes from BCC, resulting in higher BCC costs per ton. The remaining [redacted] million increase relates to updated coal prices at the Colstrip plant. The rebuttal testimony and exhibits of Ms. Natasha C. Siores address the Washington allocation of these increases.

My testimony describes: (1) the terms of the new coal and rail arrangements for Black Butte coal; (2) changes to BCC's underground mine plan; (3) the reasonableness of the BCC coal costs; and (4) changes in coal prices for the Colstrip plant.

CHANGES TO BRIDGER PLANT COAL EXPENSE

Bridger Plant Cost Summary

Q. How does the Company fuel the Bridger plant?

A. The Bridger plant is fueled by coal supplied by Black Butte and BCC. BCC is a joint venture that mines coal at the Bridger coal mine for delivery to the adjacent Bridger plant. PacifiCorp (through its wholly-owned subsidiary Pacific Minerals, Inc.) owns a two-thirds interest in BCC, and Idaho Power Company (through its wholly-owned subsidiary Idaho Energy Resources Co.) owns a one-third interest. PacifiCorp and Idaho Power Company have the same ownership percentages in the Bridger plant. BCC began supplying coal to the Bridger plant in 1974.

Q. Please summarize the [redacted] million increase in pro forma coal prices associated with the Bridger plant coal supplies.

A. Confidential Table 1 provides a summary of the price changes that are described in more detail below.

[redacted]

As reflected in this table, the costs associated with both BCC and Black Butte coal increased, reflecting updated contract prices for Black Butte and an updated mine plan for BCC. Although costs from both mines increased by different amounts, the BCC and Black Butte coal remain comparably priced. While Black Butte was slightly higher priced in the direct filing, BCC is now slightly higher than Black Butte. This is consistent with the historical BCC and Black Butte costs. In some years, BCC's production costs are lower than the third-party supply from Black Butte, and in other years, BCC's production costs are higher. On balance and over the long term, PacifiCorp's diversified approach has produced a reasonably priced, stable coal supply to the Bridger plant.

Black Butte Price and Volume Changes

Q. Please describe the increased Black Butte coal prices.

A. The increase in the delivered price of Black Butte is a result of a request for proposals (RFP) for Wyoming coal conducted by the Bridger plant owners in June 2014. As discussed in the direct testimony of Mr. Duvall, the current Black Butte coal supply agreement terminates during the first quarter of 2015. In direct testimony, the Company assumed that Black Butte coal would be supplied at the Black Butte contract deferral price.[1] The price reflected in the Company's pro forma rebuttal NPC is based on the results of the recently conducted RFP.

Q. What was the result of the June 2014 RFP?

A. The Bridger plant owners engaged both Ambre Energy, the operator of the Black Butte mine, and the Union Pacific Railroad in contract negotiations. The terms of the

[1] Direct Testimony of Gregory N. Duvall, Exhibit No. GND-1CT at 19-20.

new coal supply arrangement for the Bridger plant reflect a fixed free-on-board (FOB) price of [redacted] per ton for Black Butte coal through 2017 for approximately [redacted] tons annually, a [redacted] per ton increase. The Jim Bridger plant owners also negotiated new rail rates with the Union Pacific railroad through 2017. Including the new rail rates, the delivered price of Black Butte coal during the pro forma period has increased from [redacted] per ton to [redacted] per ton, an increase of [redacted] per ton.

Q. Please describe the updated volumes that will be delivered to the Bridger plant from Black Butte.

A. The total Black Butte volumes increased from [redacted] tons to [redacted] tons. In direct testimony, Black Butte provided [redacted] percent of the Bridger plant's coal needs; in rebuttal, Black Butte provides [redacted] percent.[2]

Q. How do the updated Black Butte coal prices and volumes increase the Bridger plant's fuel expense?

A. Approximately [redacted] million of the increase in pro forma coal expense is associated with higher Black Butte and Union Pacific transportation costs and additional Black Butte volumes.

BCC Price and Volume Update

Q. Please describe the increased BCC prices.

A. The increase in BCC prices reflects the Company's updated mine plan, which was prepared in July 2014. Under the new mine plan, BCC's volumes decrease.

[2] This volume of Black Butte coal is consistent with levels in the Company's 2013 general rate case, Docket UE-130043. *See* Rebuttal Testimony of Cindy A. Crane, Exhibit No. CAC-1T at 7, Docket UE-130043.

Approximately [redacted] million of the rebuttal pro forma coal expense is associated with BCC coal.

Q. How much of the BCC increase is related to reduced volumes?

A. Reduced coal production at BCC is the primary driver of the [redacted] per ton increase in average price from [redacted] per ton to [redacted] per ton. Decreased coal deliveries account for about [redacted] of the [redacted] per ton increase, or approximately 70 percent. Reduced surface coal deliveries account for approximately [redacted] of the [redacted] per ton increase in BCC surface costs; approximately [redacted] of the [redacted] per ton increase in BCC underground costs is associated with reduced production. A discussion of the major changes in BCC's underground mine plan is presented later in my testimony.

Q. How have the delivered volumes from BCC changed in the Company's rebuttal filing?

A. The Company's rebuttal position reflects a reduction in BCC coal deliveries from [redacted] tons to [redacted] tons, meaning that BCC is now expected to supply [redacted] percent of the Bridger plant's coal, down from [redacted] percent in the direct testimony. Confidential Table 2 below summarizes these volume changes.

[redacted]

Q. Why are BCC deliveries being reduced by approximately [redacted] tons from the amounts included in the Company's direct filing?

A. The reduction is primarily associated with updates to BCC's underground mine plan. The mine plans for both BCC's surface and underground operations were updated in July 2014, two months after the Company's initial filing was submitted. The initial filing reflected deliveries based on the most recent BCC mine plan, which was finalized in October 2013.

The reduced coal deliveries from the surface and underground mines result from reduced coal production. As reflected in Confidential Table 3 below, the underground mine will produce [redacted] million tons less coal (PacifiCorp's share) during the pro forma period.

[redacted]

Q. Is the reduced production and delivery of BCC underground coal expected to continue beyond the pro forma period in this case?

A. Yes. The underground mine is projected to produce on average [redacted] million tons per year from 2015 through 2018, or [redacted] million tons for PacifiCorp's share. Compared to the mine plan prepared in October 2013, the underground mine plan will produce, on average, over [redacted] tons (approximately [redacted] for PacifiCorp's share) less coal annually through 2018.

Q. Please explain the production changes in the underground mine reflected in the July 2014 plan.

A. There are three significant factors contributing to decreased underground production in the July 2014 plan:

- Reduction in continuous miner production shifts due to changes in workforce schedules for underground mine employees. The underground mine is now operating two 10-hour shifts, four days per week, compared to two 12-hour shifts, six days per week, in the October 2013 plan.
- A reduction in the amount of coal produced by the longwall system from [redacted] tons per shift in the October 2013 plan to approximately [redacted] tons per shift in the July 2014 plan.
- Shortening of the 15th right longwall panel.

Q. Why did BCC change the workforce schedules for the underground mine employees?

A. The underground mine has been unable to maintain two 12-hour shifts, six days per week, due to limited workforce availability. Since its inception, the BCC underground mine has experienced high turnover rates as underground miners have gained experience and pursued jobs in the trona[3] industry in Southwest Wyoming. The mine has relied heavily on contract mining services, such as Price Mine Service, to supplement the workforce. Despite the contract labor, BCC has been unable to

[3] Trona is a sodium carbonate compound that is processed into soda ash or bicarbonate of soda, or baking soda.

sustain the continuous mining activity that is necessary to support longwall panel development. The revised workforce schedule allows the mine to fully staff two 10-hour shifts, four days per week.

Q. Why is the longwall production per shift being reduced in the July 2014 plan?

A. Due to workforce shortages discussed above, the mine has been unable to sustain continuous miner development, which is essential to keep from idling the longwall system. The updated production rate allows the underground mine to balance advancement of the longwall system and continuous miner development; the steady rate of longwall production minimizes idling of the longwall and roof stability concerns.

Q. Why is the 15th right longwall panel being shortened?

A. The start-up point for the 15th right longwall panel was moved, shortening the panel length as a result of a fault encountered at the back of the panel and changes to the Bridger Coal underground ventilation plan mandated by the Mining Safety and Health Administration.

Q. Are there any other factors contributing to the increased BCC costs?

A. Yes. The reduced heat content of BCC underground coal increases coal prices approximately [redacted] million.

Q. Please discuss the change in the heat content of BCC deliveries.

A. In the Company's rebuttal, the heat content of BCC deliveries decreases from 9,301 to 9,153 British thermal units (Btus) per pound of coal due to increased ash content of the underground mine. The geological modeling in the July 2014 plan was updated to reflect actual mining conditions in areas where the coal seam height is less than 10 feet. Since the longwall is not capable of mining below 10 feet without cutting the floor or roof, the ash content was increased by approximately two percent in these areas, which contributed to a lower Btu content of coal produced from the underground mine.

REASONABLENESS OF BCC FUEL SUPPLY

Q. How does BCC pro forma period coal prices compare to other Southwest Wyoming coal supplies?

A. Favorably. As discussed earlier in my testimony, BCC prices remain comparable to Black Butte. BCC coal is also less expensive than other Southwest Wyoming coal supply options. As part of its coal RFP in June 2014, the Bridger plant owners sought coal supplies from the other coal mines in Southwest Wyoming—Westmoreland's Kemmerer mine and Kiewit Mining's Haystack mine. [redacted] in response to the solicitation. [redacted] However, [redacted] the coal would need to be transported [redacted]

Q. Has the Company provided testimony in its last two Washington rate cases describing mining operations and costs at BCC?

A. Yes. In Docket UE-111190, the Company provided extensive direct testimony on how the Company was managing coal quality at BCC. In the Company's most recent general rate case, Docket UE-130043, Boise White Paper, Inc. (Boise) argued that BCC coal should be re-priced at market prices. In response, the Company provided extensive rebuttal testimony on the reasonableness of BCC operations and costs. The Commission rejected Boise's adjustment in the final order in that case.

COLSTRIP PLANT COST SUMMARY

Q. Please explain the coal price change for the Colstrip plant.

A. The Colstrip plant is supplied by Western Energy's Rosebud mine. The rebuttal pro forma prices were based on Western Energy's 2015 Annual Operating Plan (AOP) for the Rosebud mine. The Colstrip costs included in the Company's direct filing reflected mining costs based on the 2014 AOP. Western Energy provided the Colstrip plant owners with the final 2015 AOP in October 2014. Updating pro forma coal expense to reflect the new AOP increases pro forma west control area NPC by approximately [redacted] million.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit No. RAV-2T
Docket UE-140762 *et al.*
Witness: Richard A. Vail

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF RICHARD A. VAIL

November 2014

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Q. Are you the same Richard A. Vail who previously submitted direct testimony in this case on behalf of Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp?

A. Yes.

PURPOSE OF TESTIMONY

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

A. The purpose of my rebuttal testimony is to respond to plant adjustments proposed by Mr. Bradley G. Mullins on behalf of Boise White Paper, LLC (Boise) related to three projects: the Union Gap Substation Upgrade project; the Selah Substation Capacity Relief project; and the Fry Substation project.

Specifically, I will demonstrate that Boise's proposed plant addition adjustments for these projects should be rejected and the Company should be allowed to recover the costs associated with these plant additions because these projects will be used and useful before the rate-effective date and will provide benefits to Washington customers.

UNION GAP SUBSTATION UPGRADE

Q. Please describe the Union Gap Substation Upgrade project.

A. The project involves relocating the existing distribution portion of the substation, replacing two existing 115/12.47 kilovolt (kV) transformers with one 25 Mega Volt Ampere (MVA) 115/12.47 kV transformer and relocating the third existing 115/12.47 kV transformer within the substation, where it will continue to be used and useful. The project is necessary to maintain system reliability and compliance with mandated North American Electric Reliability Corporation (NERC) reliability standards.

Q. What is Boise's proposal regarding the Union Gap Substation Upgrade?

A. Boise proposes to exclude the estimated $8.65 million in project costs associated with the first sequence of work for the Union Gap Substation Upgrade.[1] Boise claims that there are no distinct benefits from each of the three sequences of work associated with this project and, in particular, that the costs cannot be known and measurable and the assets are not used and useful until the final phase of the project is complete. Boise also assumes that the two existing 115/12.47 kV transformers replaced as part of the first sequence of work would have remained in service had it not been necessary to move them. Boise further claims that while the first sequence of work relates to distribution-level assets specifically, those costs should be functionalized as transmission costs and allocated accordingly under the West Control Area inter-jurisdictional allocation methodology (WCA).

Q. Do you agree with Boise's proposal?

A. No. This project is prudent and necessary to continue to provide safe and reliable service to Washington customers and to meet mandated NERC reliability standards.

Q. Do you agree with Boise's assertion that the first sequence of work does not provide benefits until all of the sequences are complete?

A. No. Each of the three sequences of work provides distinct known and measurable benefits to Washington customers. The project was intentionally designed in three sequences to avoid extended outages and to allow assets to be placed in service as they become used and useful and begin providing benefits to customers. Specifically, the first sequence of work included in this case will complete the distribution work for this project. When construction for the first sequence is complete, all of the

[1] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 13-14.

associated equipment, including the distribution transformers, switchgear, and related assets, will be fully used and useful to serve the local area distribution load. In addition, the first sequence provides benefits by increasing distribution capacity, replacing aged equipment, and mitigating protection system exposures.

Q. Boise assumes that the two 115/12.47 kV transformers replaced in the first sequence of work may have otherwise remained in service had it not been necessary to move them.[2] Do you agree with this assumption?

A. No. The two delivery-voltage transformers that will be removed from service are aged assets showing signs of deterioration. One was placed in service in 1931 and the other in 1941. The transformers were not identified on a separate replacement schedule because they were already part of this project design and replaced as a result. Moving the two transformers was necessary to reconfigure the distribution portion of the substation to provide additional physical space to install new equipment and facilities in the existing substation. Due to the age and condition of the 1931 and 1941 vintage transformers and the amount of physical space they occupy, it was determined to be infeasible and not cost effective to overhaul the existing banks and construct the additional foundations and structures necessary to relocate the two existing transformers to the new distribution area of the substation. Instead, a single new 115/12.47 kV, 25 MVA transformer was purchased and installed to replace the two transformers. The third existing 115/12.47 kV transformer, a 20 MVA transformer originally placed in service in 1974, was determined to be in good condition and is being relocated in Union Gap Substation as part of this project and will continue to be used and useful for distribution load service.

[2] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 14.

Q. Did the Company consider designing the first sequence of work to allow for the two transformers to remain in service or other alternative designs?

A. Yes. But trying to complete the project within the constraints of the existing substation would have required extended outages that could have compromised the reliability and operational flexibility of the system in this area. An alternative to leaving the existing 115/12.47 kV transformers in place was to construct a new adjacent substation that would have significantly increased project costs and delayed the in-service date of the project. In addition, it would not have addressed reliability issues given the age of the transformers. Reconfiguring the distribution portion of the substation was the preferred option, providing an improved and modern distribution substation at the least cost and with the least risk of extended outages. The associated distribution equipment and related assets of the first sequence provide benefits including 4 MVA of increased distribution capacity to serve local load, replacement of aged equipment and structures, mitigation of protection system exposures, and reduced future maintenance costs as any maintenance on the 115 kV main or bypass buses at the substation historically required use of a mobile transformer to serve the distribution load while the work was being completed. This is no longer required following completion of the first sequence of work. Without the improvements provided from the first sequence of work, the distribution substation would have less distribution capacity, would prolong the use of aged assets, and would result in continuing protection system exposures that could lead to outages and reduced reliability.

Q. Do you agree with Boise's claim that the project costs should be functionalized and allocated to Washington as transmission?[3]

A. No. The project costs associated with the first sequence of work are appropriately classified as distribution based on the function of the asset. Generally, assets supporting voltages 46 kV and above are considered to be used and useful for transmission purposes, but assets supporting voltages 46 kV and below are considered to be used and useful for distribution purposes. The first sequence of work involves distribution assets including, but not limited to, three 115/12.47 kV distribution substation transformers, 12.47 kV switchgear, foundations, steel structures, transrupters, cables, conductors, and pad vaults necessary to provide distribution delivery service to the local area surrounding the Union Gap substation.

Q. Has the first sequence of work been placed into service and is it used and useful?

A. The activities associated with the first sequence of work are complete and were placed in service in August 2014, except for the associated transformer relocation work. The one 115/12.47 kV transformer that is being relocated in the substation required a complete overhaul that could not be done until after the new 115/12.47 kV transformer was energized and placed in service. The relocation of this transformer will be completed in November 2014, concluding the first sequence of work and providing known and measurable benefits to Washington customers.

SELAH SUBSTATION CAPACITY RELIEF

Q. Please describe the Selah Substation Capacity Relief project.

A. This project is prudent and necessary to provide a new 115/12.47 kV distribution source at the Pomona Heights substation located north of Yakima, Washington. The

[3] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 14-15.

project will alleviate overloading on the transformers at the Selah and Wenas substations, as described in more detail in my direct testimony.

Q. What is the pro forma capital adjustment proposed by Boise for the Selah Substation Capacity Relief project?

A. Boise proposes to exclude the project costs associated with the Selah Substation Capacity Relief project.[4] Boise claims that the project costs increased by nine percent between December 2013 and July 2014 and therefore the costs are not known and measurable. Boise also claims that the project may not be placed into service by the time of hearing, but offers no evidence to support this claim.

Q. Are there any inaccuracies in Boise's testimony related to this project?

A. Yes. Boise incorrectly states that the Selah Substation Capacity Relief project was expected to be placed into service in December 2013. This is incorrect. As included in my direct testimony this project is estimated to be placed into service in December 2014.

Q. Do you expect the Selah Substation Capacity Relief project to be in service by December 2014?

A. Yes. Construction began in July 2014 and the project is 85 percent complete through October 2014. It is anticipated that all construction work will be completed in November 2014. Final project testing and commissioning work will finish in December 2014, at which point the project will be placed into service.

Q. Please explain the variance in estimated project costs.

A. The increased project costs between December 2013 and July 214 were due to increased contractor and material costs. Now that the project is substantially

[4] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 15.

complete, I do not expect significant changes to the project costs. Thus, the costs of this project are known and measurable.

FRY SUBSTATION

Q. Please explain the Fry Substation project.

A. The Fry Substation project involves installing two 20 MVA and two 30 MVA capacitor banks and three 115 kV breakers connecting to the existing bus at the substation. The project is prudent and necessary for the Company to continue to provide safe and reliable service to customers, to meet mandated NERC reliability standards, and to alleviate voltage overloads.

Q. What is the pro forma capital adjustment proposed by Boise for the Fry Substation project?

A. Boise proposes to exclude the project costs associated with the Fry Substation project due to alleged "uncertainty surrounding when the facility will be placed in service."[5] Boise also claims that the costs of the project are uncertain.

Q. Do you agree that the costs of this project should be excluded from the Company's revenue requirement?

A. No.

Q. Please explain why the in service date has moved from December 2014 (as reflected in the Company's initial filing) to February 2015.

A. In July 2014, the Company moved the expected in-service date three months, from December 2014 to February 2015. The in-service date adjustment allowed sequencing of system facility outages that are required to complete the remaining

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[5] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 15.

construction work. The additional time is also necessary to allow for testing and commissioning of the equipment and control panels associated with the project.

Q. Do you expect the Fry Substation project to be placed in service before the rate effective date?

A. Yes. Construction began in August 2014 and the project is 46 percent complete through October 2014. All the necessary outages have been scheduled and the facility upgrades are scheduled to be complete by the end of the last outage, which is scheduled to conclude on February 24, 2015. As a result, it is anticipated all work will be complete by March 2015 and the project placed into service before the rate effective date.

Q. What are the current estimated project costs?

A. The project cost included in the initial filing was based on an estimate of $6.38 million that was developed before the Company chose a contractor. Following award of the contractor bid in late July 2014, nearly three months after the Company's initial filing, the estimated project cost was updated to $7.95 million. The selected contractor provided the lowest bid for this project.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit No. DMR-2T
Docket UE-140762 *et al.*
Witness: Dana M. Ralston

BEFORE THE WASHINGTON
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PACIFIC POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF DANA M. RALSTON

November 2014

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Q. Are you the same Dana M. Ralston who previously submitted direct testimony in this case on behalf of Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp?

A. Yes.

QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota State University. I have been the Vice President of Thermal Generation for PacifiCorp Energy since January 2010. Before that, I held a number of positions of increasing responsibility with MidAmerican Energy Company for 28 years in the generation organization, including the plant manager position at the Neal Energy Center, a 1,600 megawatt generating complex. In my current role, I am responsible for operation and maintenance of the thermal generation fleet.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to proposed Chehalis and Colstrip plant outage adjustments recommended by Mr. Bradley G. Mullins in his testimony on behalf of Boise White Paper LLC (Boise). I demonstrate that the Company's actions and the costs associated with the outages were prudent.

SUMMARY OF TESTIMONY

Q. Please summarize the Company's response to Boise's proposed adjustments pertaining to the Chehalis and Colstrip outages.

A. Boise proposes adjustments related to a 2013 outage at the Chehalis plant, claiming that the outage was the result of imprudent plant operation and avoidable. Boise claims that had the Company taken additional steps based on information gathered from prior failures and monitoring equipment, the Company could have prevented the 2013 failure. My testimony demonstrates that the Company did investigate the prior failures, did not ignore any of the available information, and, in fact, used all of this information to support taking additional steps to install equipment monitors as well as working with outside experts and the Original Equipment Manufacturers (OEMs) of the equipment in question. The Company's management of the Chehalis plant was prudent, and the 2013 outage was not the result of management imprudence.

In the case of the Colstrip outage, Boise claims that outage was also caused by plant operator error. My testimony demonstrates that thorough investigation of the failure found that there was nothing that the plant operator could have done to prevent the outage and that the plant operator's actions were consistent with prudent plant operation.

CHEHALIS OUTAGE

Q. Please describe the outage that occurred at the Chehalis plant in November 2013.

A. The Chehalis plant has three generating units, and each unit has a generator step-up transformer (GSU). The GSU steps-up the generator voltage, which is 18,000 volts, to the 500,000 volts necessary for the transmission system. The 2013 outage occurred when one of the bushings on GSU 3 failed catastrophically, destroying the transformer.

Q. What is the basis for Boise's claim that the Company imprudently operated the Chehalis plant resulting in the 2013 outage?

A. Boise argues that the Company could have prevented the 2013 outage at Chehalis by using the information from two prior outages, in 2006 and 2011, as well as available monitoring data.[1]

Q. Do you agree with Boise's claim that the two prior outages should have caused the Company to operate the plant in a way that would have prevented the 2013 outage?

A. No. The 2006 outage was caused by a catastrophic failure of a bushing external to GSU 3 that destroyed the entire transformer. The root cause analysis that followed the 2006 outage, conducted by NGK (the bushing OEM) and Transformer Services, Inc., was unable to identify a specific root cause for the transformer's failure. And because GSU 3 was destroyed by the failure, the plant operator at the time (this pre-dated the Company's acquisition of the plant) replaced the transformer and bushing in 2007. Thus, the Company had no reason to believe further remedial action was required as a result of the 2006 outage.

Q. What was the cause of the 2011 outage?

A. The 2011 outage resulted from a failure of a bushing internal to GSU 1. The Company's investigation following the 2011 outage was comprehensive and included review by both the Company's own experts and third parties, including ABB Inc., the transformer manufacturer (FUJI), and the bushing manufacturer (NGK). The investigation included industry-standard electrical testing on GSU 2 and GSU 3,

[1] Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 50-53.

including the bushings, internal transformer tank inspections of the failed unit, inspections of all three bushings from the failed transformer, and oil quality analysis. Despite this thorough investigation, a definitive root cause for the bushing failure in 2011 was not determined. The bushing manufacturer believed it was a transformer assembly issue, and the transformer manufacturer suspected it was a bushing issue. ABB Inc. believed the outage was due to an internal bushing failure, but whether that was a manufacturing or installation defect was not determined. Testing performed after the 2011 outage showed that Units 2 and 3 were suitable for service. Because a definitive root cause was never determined, there was no reasonable basis to take affirmative action to replace the GSUs because such action would have been based on speculation, not facts, and would have resulted in unjustifiable costs.

Q. Did the analysis following the 2011 outage shed any light on the 2006 outage?

A. Yes. In a subsequent report issued by NGK after the 2011 outage, NGK identified the most likely root cause of the 2006 event as damage to the bushing assembly during original installation. Again, that entire transformer, GSU 3, was replaced following the 2006 outage, and there was no reason to believe that when the new unit was installed the same damage occurred.

Q. What were the Company's options in 2011 without a definitive root cause of the failure?

A. Because there was no root cause identified and the transformer and bushing manufacturers asserted each of their designs was sound, the Company had two options: (1) install additional monitoring equipment to see if a failure mode and imminent failure could be identified; or (2) replace both remaining transformers at a cost of over eight million dollars, not including the associated outage time required to install the transformers. Due to the uncertainty regarding whether the failures were anomalies or indicative of a widespread issue with the transformer or bushings, the Company proactively installed online dissolved gas analyzers and bushing monitoring equipment on the remaining transformers in 2011 and 2012, respectively.

Q. Was the data provided by the new monitors reviewed and considered by the Company in its decision to continue to operate the transformer before the 2013 outage?

A. Yes. The Company regularly analyzed the data provided by the monitors to assess whether there was a risk of additional failures. Whenever the data indicated that abnormal conditions were present, it was immediately reported to Chehalis plant personnel from the bushing monitoring equipment. When the Company received abnormal condition notices, the Company contacted the OEM to determine if the abnormal condition warranted action by the Company, such as removal of the transformer from service. In one instance, the Company discovered that the OEM had incorrectly commissioned the equipment. This issue was corrected before the 2013 failure.

Q. On the day of the 2013 failure, was there any indication from the GSU 3 monitors to suggest failure was imminent?

A. No. On the day of the failure, the bushing health monitor did not report values in either the non-critical or the critical alarm ranges.

Q. The report issued following the 2013 outage included recommendations regarding the monitoring equipment. Boise implies that these recommendations suggest that the Company's actions before the 2013 outage were imprudent.[2] Do you agree?

A. No. The Company was monitoring the situation using all of the information available at the time, and no alarm values existed on the day of the failure until the actual failure occurred. The recommendations were improvements to data availability. Boise is implying that the data was not available to the plant, which is incorrect. There is no basis to assume that if the Company had implemented all of the recommendations in the 2013 report that the 2013 outage would have been avoided.

Bushing monitors are not typical of transformer installations, and, in fact, these are the only monitors in the entire PacifiCorp fleet. The monitors were installed with the expectation they would provide valuable data to the Company, but as we have learned, the accuracy of the monitors has been questionable, causing false indications. The Company and the OEM continue to work to resolve these issues to improve the value of the system.

Q. Has the Company implemented the recommendation referenced by Boise in the 2013 report?

A. Yes. The Company implemented the recommendations after the report was issued.

Q. What did the Company do after the 2013 failures to prevent future issues?

A. In conjunction with bushing suppliers and insulation experts, the Company installed higher rated bushings on GSU 2 (the only remaining FUJI transformer) from a

[2] Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 52.

different supplier and custom modified the bushing shields. Based on the engineering review by the insulation experts, we believe this will provide a superior design compared to the original design.

Q. Why didn't the Company replace the bushings after the 2011 failure?

A. First and foremost, the Company did investigate the possibility of replacing the bushings in 2011 with the transformer manufacturer. High voltage bushings are integral to any transformer design and as such the transformer manufacturer should normally approve their replacement. Transformer bushings are not universally interchangeable; the Company could not have just selected another manufacturer and installed different bushings without an extensive engineering review. The Company was informed in 2011 by the transformer OEM that its only option would be to replace the bushings with identical NGK bushings. Replacing the existing bushings with identical bushings when the existing bushings had passed testing with acceptable results did not appear to provide any benefit, especially where no definitive root cause was identified. After the 2013 failure, the Company determined that it was necessary to ask other industry experts what it could do to replace the bushings as the transformer manufacturer was not providing solutions to this problem. The bushings were replaced with ABB bushings after outside experts reviewed the transformer design and bushing application. As a result of the review, non-standard modifications were also required to the bushing shields to accommodate the ABB bushings. After the Company performed the review with outside experts, the new bushings and modifications were installed, and the transformer was put back in service.

Q. Do you believe the Company used all available information to prudently manage the Chehalis plant and minimize risk of outages?

A. Yes. Following the 2006 and 2011 outages, the Company prudently engaged in a full battery of tests and involved the transformer and bushing OEM, outside experts, and the Company's subject matter experts in the root cause analysis. The results of the root cause analysis for the 2006 and 2011 outages were inconclusive and without a definitive root cause. Also, because the failure modes were different in 2006 and 2011, the Company took prudent and proactive actions to monitor the issue. The Commission should find that the 2013 outage was not the result of imprudent plant operation.

COLSTRIP OUTAGE

Q. Boise argues that the Colstrip outage was caused by plant operator error as a result of repair work that was done at the time of a prior outage.[3] Is there any basis for Boise's claim of operator imprudence?

A. No. Boise claims that because the root cause scenario could not identify with certainty the cause of the outage, the analysis does not support a conclusion that the operator was not at fault. But the root cause analysis states that, "[a]lthough there was no 'smoking gun' which clearly indicated the cause of failure **there were a set of facts and timing available to form the basis for the most likely failure scenarios**."[4] The "facts and timing" analyzed in the root cause report supported the conclusion that the operator was not at fault.

Boise suggests that factual evidence available was not adequate to develop a

[3] Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 66.

[4] Testimony of Bradley G. Mullins, Exhibit No. BGM-4C (emphasis added).

failure cause and that concrete evidence and a clear indication of failure must be present to show the Company's actions were prudent.[5] However, the failure report was very detailed and used all the information available, including plant logs, relay and alarm data, and physical inspections of the damage by industry expects. Boise discounts the statement by the external root cause investigating team that, "[i]n our opinion, PPL did everything according to standard industry practice such as hiring the OEM (Siemens) to perform the maintenance, performing El Cid testing on the core, operating their unit according to industry practice, (since there was no indication of mis-operation), and protecting the unit with adequate relay protection. Nothing they did or could have done, could have prevented this failure."[6] This statement, along with the rest of the report, demonstrates that the Company acted prudently and took all recommended steps to maintain the equipment as per the OEM recommendations.

The implication of Boise's argument is that in the absence of definitive evidence of the cause of an outage, the Company cannot demonstrate that the plant operator was prudent. This implication is unreasonable.

Q. Is there any evidence supporting Boise's conclusion that the repair work following the prior outage was the cause of this outage?

A. The root cause analysis indicates that prior repair work "could" have caused initial damage that ultimately lead to the outage. However, the experts that authored the root cause analysis nonetheless found that the plant operator was prudent and that the available evidence did not indicate that the operator could have prevented the outage.

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[5] Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 65.
[6] Testimony of Bradley G. Mullins, Exhibit No. BGM-4C.

Thus, Boise's claim is speculation unsupported by the expert analysis in the root cause report.

FLEET PERFORMANCE

Q. How did the PacifiCorp fleet perform in 2013?

A. In 2013 the average equivalent availability factor (EAF) for the PacifiCorp thermal fleet on an ownership basis was 90.65 percent and includes the outages at Chehalis and Colstrip, while the 2012 NERC average for a comparable fleet was 82.60 percent. This is over eight percent better than the industry average. This data shows our customers are receiving a significant benefit and PacifiCorp effectively and prudently operates its generating fleet.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit No. EDW-2T
Docket UE-140762 *et al.*
Witness: Erich D. Wilson

BEFORE THE WASHINGTON
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PACIFIC POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF ERICH D. WILSON

November 2014

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Q. Are you the same Erich D. Wilson who previously submitted direct testimony in this case on behalf of Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp?

A. Yes.

PURPOSE OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address certain labor-related adjustments proposed by Public Counsel witness Ms. Donna M. Ramas. Specifically, I address Public Counsel's pro forma wage adjustment, workforce level adjustment, and adjustments related to the Company's pension expense and Other Post-Employment Benefits (OPEB).

Q. Please summarize your testimony.

A. The Company included pro forma adjustments to its wage and salary expense to most closely match the expenses expected during the rate-effective period. This approach is conceptually consistent with past Commission precedent allowing pro forma adjustments to ensure accuracy in the Company's labor costs. Consistent with past rate filings, the Company included a pro forma wage and salary adjustment, but did not include pro forma adjustments for other components of its labor expenses.

Public Counsel is the only party that challenged the Company's labor expenses, proposing adjustments to remove portions of the pro forma wage and salary adjustment, reflect temporarily lower workforce levels, and include selective pro forma adjustments for pension and OPEB expense. Public Counsel's adjustments are inconsistent with prior Commission orders and should be rejected.

WAGES AND SALARIES

Q. How did the Company calculate its wage and salary expense in this case?

A. The Company included a pro forma adjustment to reflect salary and wage expenses at the level expected in the rate-effective period. The adjustment is based upon known and measurable increases under union contracts and known or anticipated increases for the non-union workforce.

Q. Please explain Public Counsel's adjustment to wages.

A. Public Counsel criticizes the Company for including projected wage increases through the rate-effective period. Public Counsel recommends that the pro forma wage and salary increases be limited to the actual known and measurable increases occurring within 12 months of the end of the test year, or through December 31, 2014.[1] Public Counsel argues that the proposed pro forma adjustment extends too far beyond the test year. This adjustment would reduce the Company's revenue requirement by approximately $680,000 on a Washington-allocated basis.

Q. Do you agree with this adjustment?

A. No. As Public Counsel recognizes, the Commission already has a history of allowing pro forma wage and salary increases that extend beyond the test year. The Company's pro forma adjustment in this case is conceptually consistent with that precedent, seeking to most accurately capture the costs expected to occur in the rate-effective period. This approach is also conceptually consistent with the Commission's allowance of projected and updated net power costs for the rate-effective period.

[1] Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 19-21.

Q. Please summarize the Commission's orders allowing pro forma wage and salary adjustments.

A. In the Company's 2010, 2011, and 2013 rate cases (Dockets UE-100749, UE-111190, and UE-130043, respectively), the Company's filing included pro forma adjustments to the test year wage and salary levels to reflect known and measurable changes. In the 2010 rate case, the pro forma adjustments reflected wage and salary increases occurring within 12 months of the end of the test period. In that case, the Commission expressly rejected parties' proposals to remove the pro forma adjustments, finding that the "pro forma wage increases reflect known and measurable changes, and we approve them."[2]

Similarly, in the 2011 rate case the Company included pro forma wage and salary adjustments to reflect the known and measurable changes occurring during the 12 months following the test period. Parties again objected to the increase. Ultimately, the 2011 rate case was resolved by a stipulation that did not specifically address wages and salaries.

In the 2013 rate case, the Company again included a pro forma wage and salary adjustment, this time without objection from the parties.

Q. The Company's pro forma adjustment extends farther beyond the test year than the adjustments the Company has proposed in prior cases. Is there any precedent supporting this adjustment?

A. Yes. Although the Company did not include adjustments reflecting the rate-effective period in its prior cases, Avista Corporation, d/b/a Avista Utilities, has used this

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[2] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06 ¶¶ 226-235 (Mar. 25, 2011).

approach in prior cases.[3]

Q. Does the Company's pro forma adjustment satisfy the Commission's known and measurable standard?

A. Yes. The wage and salary expense reflected in the pro forma adjustment for union employees represents the actual contractual amounts that the Company will pay to those employees during the rate-effective period. These contractual wages and salaries are market based, resulting from negotiations with the unions.

Similarly, the Company's pro forma adjustment for non-union employees represents a conservative, market-based wage level that is representative of the wages and salaries that will be paid during the rate-effective period. The non-union wage and salary expenses are known and measurable because they are based on the actual increases set as of December 26, 2014, and the planned wage and salary increases through the rate-effective period. The planned increases are consistent with the Company's historical wage increases, both in terms of the timing of the increase and the percentage increase.

EMPLOYEE REDUCTIONS

Q. What employee levels did the Company use to determine its labor expenses during the rate-effective period?

A. The Company used employee levels from the historical test period to determine its labor expense.

Q. Please explain Public Counsel's adjustment to the employee levels.

A. Public Counsel claims that the Company's number of full-time-equivalent (FTE)

[3] *See e.g.*, *Wash. Utils. & Transp. Comm'n v. Avista Utilities*, Docket UE-120436, Direct Testimony of Elizabeth M. Andrews, Exhibit No. EMA-1T at 28 (Apr. 2, 2012).

employees has decreased since the test period and that the revenue requirement should be based on the number of employees as of June 2014.[4] Public Counsel's adjustment would reduce the total number of FTE employees by 67 or 1.24 percent. This adjustment results in a reduction to revenue requirement of approximately $380,000 on a Washington-allocated basis.

Q. Do you agree with this adjustment?

A. No. While it is true that the number of employees temporarily decreased between the test year and June 2014, it is the Company's intent to fill these vacancies and the Company was and is actively recruiting. For example, vacancies in journeyman craft positions are backfilled through various ways, including external hiring, creating apprenticeships, or by using temporary employees or contractors. Many of the Company's service areas can present real challenges in terms of attracting and retaining qualified candidates so a variety of methods are used to try and fill vacant positions.

Q. Is there any evidence that the June 2014 workforce level is indicative of the number of employees during the rate-effective period?

A. No. The Company's staffing numbers are dynamic and constantly changing. In fact, from April 30, 2014, through August 31, 2014, the Company added 376 employees, while also sourcing for an additional 326 positions that became vacant during the same time period.

[4] Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 22-24.

Q. Has the Commission previously rejected adjustments similar to the one proposed by Public Counsel?

A. Yes. In the Company's 2010 rate case, the Industrial Customers of Northwest Utilities (ICNU) and Public Counsel argued for a similar type of adjustment, claiming that PacifiCorp had experienced workforce reductions since the end of the test period.[5] The Commission rejected the ICNU and Public Counsel adjustment because they failed to demonstrate that the workforce reductions were permanent.[6] In that case, like here, the workforce reductions were temporary and due to hiring lag. Public Counsel provided no evidence to suggest that the June 2014 employee levels represent a permanent reduction in workforce that should be reflected in rates.

Q. If the Company is unable to fill positions, will the expense level go down correspondingly?

A. No. The amount of work and ultimately the dollars required to complete the work is not dependent on the number of FTE employees. The Company uses a mix of FTE employees and contract labor to perform specific planned and unplanned work that is required to offer safe, reliable service. When sufficient internal resources are not available to complete all work plan requirements, external resources are used to complete required work activities. If the revenue requirement is reduced for assumed reductions in employee levels, the Company would require a corresponding adjustment to increase non-labor expense. The amount of work required to be completed has not decreased and no reduction in the allowed expense should be

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[5] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Responsive Testimony of Greg R. Meyer on Behalf of the Industrial Customers of Northwest Utilities and Public Counsel, Exhibit No. GRM-1CT at 22-23 (Oct. 5, 2010).

[6] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 232 (Mar. 25, 2011).

incurred due to FTE numbers. The Company must maintain the safe, reliable service that customers depend on and, in doing so, will continue to use a mix of FTE employee and contract services to complete the necessary operations and maintenance work.

PENSION AND OPEB EXPENSE

Q. How did the Company calculate the pension and OPEB expense levels that were included in its initial filing?

A. Consistent with prior filings, the Company included the historical test-year expenses in its initial filing.

Q. Please describe Public Counsel's proposed adjustments to pension and OPEB expense.

A. Public Counsel recommends that the pension and OPEB expense be updated to reflect amounts for 2014.[7] Public Counsel argues that these amounts are known and measurable changes. Public Counsel's adjustments reduce pension expense by approximately $1.2 million and OPEB expense by approximately $100,000, both on a Washington-allocated basis.

Q. Do you agree with Public Counsel's pension and OPEB expense adjustments?

A. No. Public Counsel's adjustments are inconsistent with prior pension and OPEB expense treatment and unreasonably single out these expenses for pro forma adjustment. The Company's prior filings consistently used the test-year pension and OPEB expenses, without controversy.

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[7] Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 24-28.

Q. How do you reconcile your rejection of Public Counsel's pension and OPEB expense adjustment with your recommendation to adjust wages and salaries to reflect amounts through the rate-effective period?

A. As discussed above, the Company's treatment of wage and salary expenses is consistent with past filings by both Pacific Power and other Washington utilities, which have used known and measurable pro forma adjustments to more accurately reflect the wages and salaries during the rate-effective period. However, even though the Company uses pro forma adjustments for wages and salaries, it does not make similar adjustments for other labor costs, such as pensions, OPEB, or other employee benefits (like health-care benefits). For example, in the 2010 rate case discussed above, the Commission specifically approved the Company's pro forma wage and labor adjustment while observing that "PacifiCorp did not adjust changes in workforce levels, employee benefits and incentives, or pensions."[8]

Q. Why is it problematic to provide pro forma adjustments for only pension and OPEB expenses?

A. Adjusting only two components to decrease the Company's total labor-related expenses, without making corresponding adjustments to the other labor-related expense components that will offset the increases is inconsistent and unfair.

RECOMMENDATION AND CONCLUSION

Q. What is your recommendation to the Commission?

A. I recommend that the Commission approve the Company's proposed labor expenses as consistent with prior Commission orders. I further recommend that the

[8] Docket UE-100749, Order 06 ¶ 226.

Commission reject Public Counsel’s proposed adjustments to wages and salaries, workforce levels, and pension and OPEB expense.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit No. NKR-1T
Docket UE-140762 *et al.*
Witness: Norman K. Ross

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF NORMAN K. ROSS

November 2014

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Q. Please state your name, business address, and present position with Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp.

A. My name is Norman K. Ross. My business address is 825 NE Multnomah Street, Suite 1900, Portland, Oregon 97232. I am employed as a Tax Director within the Company's Tax Department.

QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I received a Bachelor's degree in Business Administration with an emphasis in accounting from Seattle Pacific University in 1980. I am licensed as a Certified Public Accountant in the state of Washington. I also hold an Accreditation in Business Valuation (ABV) appraisal credential from the American Institute of Certified Public Accountants. In addition to my formal education, I have attended numerous professional courses many of which during recent years involved valuation related training. I have been employed by the Company in my present role since July 1998. Between 1987 and 1998, I was employed within the tax department of Pacific Telecom, Inc., PacifiCorp's former rate regulated telecommunications subsidiary. My duties while at Pacific Telecom involved both income and non-income (sales, use, gross receipt, property, etc.) tax obligations. I have previously testified in regulatory proceedings before the Utah Public Service Commission and the Public Utility Commission of Oregon, and as an expert valuation witness during administrative level tax appeals before state taxing agencies and during formal hearings and district court trials in the states of Idaho, Montana, Oregon, Utah, Washington, and Wyoming. I have testified before state legislative subcommittees on matters related to the taxation of public utility operating property and proposed tax legislation.

Q. What are your present duties?

A. My responsibilities as a Tax Director include oversight of all compliance, accounting, financial reporting, financial planning, audit, and appeal-related activities related to the Company's sales, use, excise, franchise, public utility, gross receipt, and property taxes as well as public utility fees payable to cities and states in which the Company operates. Because property tax represents the Company's single largest operating tax expense item, much of my day-to-day work focuses on matters related to the valuation of the Company's operating property for property tax assessment purposes.

PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to provide an overview of the property tax assessment and estimation process and to respond to testimony provided by Washington Utilities and Transportation Commission Staff (Staff) witness Mr. Jason L. Ball in which he opposes the pro forma property tax adjustment included in this case.

OVERVIEW OF PROPERTY TAX ASSESSMENT AND ESTIMATION PROCESS

Q. Please provide an overview of the property tax assessment process.

A. The Company's operating property is valued on a centralized basis by appraisers on staff in each state's department of revenue or tax commission. This valuation is unlike most commercial property, which is typically reported to and valued on a county-specific level. The centralized valuation process has historically been employed for companies whose property is operated in an integrated and interdependent manner across both county and state boundaries. The centralized valuation process employs approaches, procedures, and techniques that are more common to business valuation. The two most significant inputs relied upon during the valuation process are the net unrecovered investment in the Company's operating property and the expected cash flows that will be derived from the operation of such property over time. These two fundamental inputs are employed within the cost and income approaches to value for the purpose of estimating the market value of taxable property.

Q. How did the Company calculate the property tax expense that is included in this case?

A. As described in Ms. Natasha C. Siores' direct testimony, the Company included a pro forma adjustment to normalize the difference between the actual accrued property tax expense and the pro forma property tax expense for the 12 months ending December 31, 2014.[1]

Q. How did the Company produce a pro forma property tax adjustment?

A. The specific procedures the Company employs when determining the value of operating property and the associated amount of property tax expense are discussed in greater detail in confidential Exhibit No. NCS-4C, submitted with the direct testimony of Ms. Siores in this case. To summarize that exhibit, the Company uses the state-specific valuation procedures (cost and income approaches) commonly employed by each state's appraisal staff. Estimates are prepared in conformity with

[1] Direct Testimony of Natasha C. Siores, Exhibit No. NCS-1T at 23.

state-specific laws and administrative rules while taking into account available exemptions from taxation.

Q. Generally, do the factors that impact the calculation of property tax expenses change from year to year?

A. No. Although the absolute amount of property tax payable for a given year and state is not known until tax bills arrive, the factors that contribute to the Company's annual property tax payment obligations are either known or forecast so that property tax expense can be determined for use in the Company's revenue requirement. Importantly, neither the laws governing the types of property subject to property tax assessment nor the specific appraisal methods annually employed by the various states when appraising the Company's operating property vary significantly from year to year. The Company's determinations of assessed values in the pro forma period are based upon the application of known state-specific appraisal methodologies. And although property tax rates change to some extent from year to year, the degree of change from one year to the next is not typically significant.

Q. Does the Company's approach to property tax expense in this case differ from its approach in the last general rate case?

A. No. The Company's approach and the property tax adjustment it proposes in this case are consistent with its approach in the previous case, Docket UE-130043. In both cases, the Company proposed that property tax expense be walked forward one year using the Company's pro forma property tax adjustment.

Q. Has Staff previously objected to the Company's pro forma property tax adjustment?

A. Yes, for similar reasons to those presented in this case.[2] After the Company updated the adjustment using actual information through June 2013, Staff accepted the Company's adjustment.[3] Like the last case, the Company is updating the adjustment with actual information, although given the difference in the timing of the filing of the initial application, the Company is updating with nine months of actual information and three months of pro forma property tax expense. This update is described in the rebuttal testimony of Ms. Siores.

Q. Did the Commission approve the Company's pro forma adjustment in Docket UE-130043?

A. Yes.[4]

Q. To what extent has the Company's estimates of property tax expense varied from actual expense over time?

A. Total property tax expense over the preceding five-year period, from 2009 through 2013, varied from estimated expense by less than one percent. This small variance indicates that the Company's pro forma adjustment is known and measurable.

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[2] *Wash. Utils. & Transp. Comm'n v. PacifiCorp,* Docket UE-130043, Testimony of Betty A. Erdahl, Exhibit No. BAE-1T at 4-5 (June 21, 2013).
[3] *See Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Revised Final Issues List (Aug. 23, 2013).
[4] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Order 05, Appendix A (Dec. 4, 2013).

RESPONSE TO STAFF TESTIMONY

Q. Staff also reasons that the Company's property tax adjustment should be rejected in favor of retaining a "representative amount of property tax expense relative to the revenues and rate base…in rates."[5] Do you agree?

A. No. First, neither the methods employed by states when determining the assessed values of the Company's operating property nor the tax rates applied to those values are directly a function of either revenues or rate base. Rather, assessed values and the associated amount of property tax expense are a function of the market value of the Company's taxable operating property.

Second, given year-over-year increases in the Company's investment in taxable operating property, future-period tax expense is certain to be higher than the "representative amount" of property tax expense derived from the historical test period. The Company's proposed adjustment reflects the higher property tax expense amount that logically results from increases in taxable operating property and corresponding increases in net utility operating income.

Finally, Staff's proposal to limit property tax expense to a historical amount invites the Commission to adopt an approach toward ratemaking that falls short of matching operating tax expense with the revenue stream needed to fund the payment of such taxes. Staff proposes that customer rates be set by reference to a 2013 property tax expense level that is no longer relevant. The appropriate amount of property tax expense to include when determining the Company's revenue requirement is the amount of expense to be incurred during the rate-effective period.

[5] Testimony of Jason L. Ball, Exhibit No. JLB-1T at 19.

Q. How does actual property tax expense for 2013 compare with the amount of property tax expense the Company expects to incur for 2014 and 2015?

A. The Company recorded $122.6 million in property tax expense for 2013 and expects to record on a normalized basis $124.2 and $133.1 million in property tax expense for calendar years 2014 and 2015, respectively. By the time electric rates are adjusted at the conclusion of this case, the Company's annual property tax expense is expected to be $10.5 million higher ($133.1 million – $122.6 million = $10.5 million) than the amount that Staff asks the Commission to include when quantifying the Company's revenue requirement. Staff's recommendation will result in an understatement of the Company's revenue requirement for property tax expense during the rate-effective period.

Q. What is the amount of property tax expense included in the Company's rebuttal revenue requirement?

A. As discussed in the rebuttal testimony of Ms. Siores, the Company's rebuttal revenue requirement reflects property tax expense of $124.2 million, which is the normalized amount the Company anticipates recording for calendar year 2014. As discussed above, this amount includes nine months of actual data and three months of pro forma data. And this amount is still far less than the property tax expense that the Company anticipates incurring in the rate-effective period.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit No. NCS-10T
Docket UE-140762 *et al.*
Witness: Natasha C. Siores

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF NATASHA C. SIORES

November 2014

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ATTACHED EXHIBITS

Q. Are you the same Natasha C. Siores that previously provided testimony in this case on behalf of Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to quantify and explain the corrections, revisions, and updates made to the Company's proposed revenue requirement and to respond to testimony of the staff of the Washington Utilities and Transportation Commission (Staff) witnesses Ms. Betty A. Erdahl, Mr. Jason L. Ball, and Mr. David C. Gomez, the Public Counsel Section of the Washington State Attorney General's Office (Public Counsel) witness Ms. Donna M. Ramas, and Boise White Paper, LLC (Boise) witness Mr. Bradley G. Mullins (collectively, the Parties).

Q. Please summarize your testimony.

A. My testimony explains and supports the Company's revised overall revenue requirement increase of $31.9 million. This is an increase of $4.7 million from the amount requested in the Company's initial filing as a result of revisions, corrections, and updates to various revenue requirement components. My testimony also provides the Company's response to certain revenue requirement adjustments proposed by Staff and other intervening parties.

Finally, my testimony explains the Company's position on the appropriate treatment of the deferred accounting requests that were consolidated into this general rate case.

REVENUE REQUIREMENT

Q. What price increase is required to achieve the requested return on equity in this case?

A. As shown on Page 1 of Exhibit No. NCS-11, an overall base price increase of $31.9 million is required to produce the 10.0 percent return on equity requested in this case.

Q. Please describe the calculation of the revised overall revenue increase.

A. The Company's revised revenue increase of $31.9 million is calculated using the West Control Area inter-jurisdictional allocation methodology (WCA). In support of the revised calculation, Exhibit No. NCS-11 shows the Company's revised Washington revenue requirement. This exhibit incorporates revisions to certain adjustments made in the Company's initial filing and provides updates to the revenue requirement summary and account detail portions (tabs 1 and 2) of my original Exhibit No. NCS-3.

Q. Is the Company incorporating any of the updates, corrections, or adjustments proposed by the Parties in its rebuttal revenue requirement calculation?

A. Yes, the Company incorporated the following revisions to revenue requirement adjustments proposed in its initial filing, including some adjustments proposed by the Parties. Each is described in more detail later in this testimony.

Filed Revenue Requirement		**$27,201,266**
Adjustments Withdrawn by Company in Rebuttal		Revenue Requirement Impact ($)
3.8	Schedule 300 Changes	$87,440
4.12	Collection Agency Fees	$44,138
Total Impact of Withdrawals		***$131,577***
Revised Revenue Requirement		**$27,332,843**
Adjustments Revised by Company in Rebuttal		Revenue Requirement Impact ($)
4.11	Legal Expenses	($127,537)
4.13	IHS Global Insight Escalation	($6,911)
6.2	Depr & Amort Res to December 2013 Balance	($1,256,047)
6.5	Retired Asset Depreciation Expense Removal	($28,755)
8.5	Miscellaneous Rate Base	$393,350
8.11	Miscellaneous Asset Sales & Removal	$375,239
Total Impact of Revisions		***($650,662)***
Revised Revenue Requirement		**$26,682,182**
Updates to Pro Forma made by Company in Rebuttal		
5.1.1	Net Power Cost (Pro Forma)	$5,693,116
7.2	Property Tax Expense	($427,676)
7.7	Remove Deferred State Tax	$613
8.4	Pro Forma Major Plant Additions	($52,879)
9.1	Production Factor	$43,602
Total Impact of Updates		***$5,256,776***
Rebuttal Revenue Requirement		**$31,938,957**

Q. Please describe Exhibit No. NCS-11.

A. Exhibit No. NCS-11 is the Company's Washington Results of Operations Report (Report), revised to incorporate changes and updates outlined in the table above. The Report is organized in a manner similar to Exhibit No. NCS-3:

- Tab 1 (Summary) reflects the Washington-allocated results based on the WCA.
- Tab 2 (Results of Operations) details the Company's overall rebuttal revenue requirement by Federal Energy Regulatory Commission (FERC) account and WCA allocation factor.

- Tabs 3 through 9 provide supporting documentation for restating and pro forma adjustments that have been revised or updated in the calculation of the Company's rebuttal revenue requirement.

REVENUE ADJUSTMENTS

Schedule 300 Fee Changes

Q. Do parties contest the Schedule 300 fee changes proposed by the Company in its initial filing?

A. Yes, multiple parties oppose the Schedule 300 Fee changes proposed in the Company's initial filing. Ms. Joelle R. Steward's rebuttal testimony addresses these issues.

Q. Did the Company make any revisions to the adjustment for Schedule 300 fee changes?

A. Yes, consistent with the discussion in Ms. Steward's rebuttal testimony, except for the change in tampering/unauthorized reconnect charges, the Company has withdrawn all proposed Schedule 300 fee change impacts from the Company's revenue requirement calculation. The revised adjustment 3.8 (Schedule 300 Charges) increases revenue requirement by approximately $87,000.

OPERATION AND MAINTENANCE AND ADMINISTRATIVE AND GENERAL EXPENSES

General Wage Increases

Q. Please summarize Public Counsel's position regarding the Company's proposed general wage increase adjustment.

A. Public Counsel recommends several modifications to the Company's proposed general wage adjustment. Specifically, Public Counsel recommends:

- Limiting wage increases to those occurring by December 31, 2014;
- Reducing full-time-equivalent (FTE) employees (and associated costs) to reflect the actual FTE employee level as of June 2014;
- Reducing pension and other post-retirement employee benefits (OPEB) expenses to reflect information provided by the Company through discovery.[1]

Q. Does the Company agree with Public Counsel's recommendations on the general wage increase adjustment?

A. No. The Company maintains that the proposal supported in its direct filing is appropriate. As explained in my direct testimony, the Company annualized calendar year 2013 wage amounts by taking into account actual wages by labor group by month along with the dates each labor group received wage increases. The Company then adjusted wage levels through the rate-effective period by applying known and measurable pro forma wage increases that have occurred or are expected to occur through March 31, 2016. Reflecting wage levels in this manner more appropriately aligns wage and salary expense levels with the level of expense the Company will incur during the period in which rates will be effective. In addition, this treatment is consistent with the approach taken by Avista Corporation, d/b/a Avista Utilities (Avista) in its last general rate case.[2] The appropriateness of this methodology is discussed in greater detail in the rebuttal testimony of Mr. Erich D. Wilson.

Q. What is the Company's position on Public Counsel's recommendation regarding FTE levels and pension and OPEB expenses?

A. The Company disagrees with Public Counsel's proposed adjustments. As discussed

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[1] Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 19-28.

[2] *See e.g.*, *Wash. Utils. & Transp. Comm'n v. Avista Utilities*, Docket UE-120436, Direct Testimony of Elizabeth M. Andrews, Exhibit No. EMA-1T at 28 (Apr. 2, 2012).

in Mr. Wilson's rebuttal testimony, Public Counsel's work force reduction adjustment is not appropriate because the Company is actively working to fill vacancies.

As discussed by Mr. Wilson, Public Counsel's proposed adjustment to reduce pension and OPEB expense levels, which reduces the Company's revenue requirement, does not consider other employee benefit costs that have increased since the historical period, such as health-care benefits. The Company has not proposed pro forma changes to employee benefits in this case, which is consistent with the treatment approved by the Commission in the Company's 2013 general rate case. If pension and OPEB expense levels are adjusted from historical test period levels, other employee-benefit-related items should also be adjusted.

Q. Are there any problems with Public Counsel's calculation of its pension adjustment?

A. Yes. It appears Public Counsel calculated its pension expense adjustment by incorrectly comparing the pension expense from an actuarial report to the Company's total pension expense reflected in the historical base period. This comparison is improper because the actuarial report relied on by Public Counsel does not include costs of the Local 57 multi-employer plan. Local 57 multi-employer plan costs, however, are included in the Company's base historical period. Accordingly, Public Counsel's adjustment effectively eliminates all costs associated with the Local 57 multi-employer plan, which overstates its adjustment by approximately $411,000 on a Washington-allocated basis.

Insurance Expense

Q. Please describe the insurance expense adjustments proposed by Staff and Pubic Counsel.

A. Insurance expense in the Company's initial filing was based on a six-year average of actual damage expenses, which is consistent with the all-party stipulation in the Company's 2011 general rate case, Docket UE-111190,[3] and the Commission's approval of the methodology used in the Company's 2013 general rate case.[4] In this case, Staff recommends excluding the 2012 insurance expense amount from the six-year average calculation and substituting it with the 2007 expense amounts to calculate a new six-year average.[5] Staff asserts that the replacement of the 2012 insurance expense with the level from 2007 is more representative of the level of expense that is expected to occur during the rate-effective period. Staff's adjustment reduces the Company's Washington revenue requirement by approximately $237,000.

Public Counsel recommends excluding two incidents from the 2012 insurance expense amount from the calculation of the six-year average in the Company's filing, referring to the 2012 expense amount as an "anomaly" due to the above-average amount recorded.[6] Public Counsel also questions whether the two incidents are appropriately allocated to Washington. The amount not covered by insurance for each of these incidents is $10 million. Therefore, Public Counsel recommends excluding $20 million (on a total-company basis) from the 2012 insurance expense

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[3] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-111190, Settlement Stipulation at 5 (Feb. 21, 2012).
[4] *See Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Revised Final Issues List (Aug. 23, 2013).
[5] Testimony of Jason L. Ball, Exhibit No. JLB-1T at 13-15.
[6] Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 31-35.

used to calculate the six-year average, resulting in a decrease in insurance expense of $3.3 million on a total-company basis, or approximately $228,000 on a Washington-allocated basis.

Q. What is the Company's response to the proposed adjustments to insurance expense?

A. Both Public Counsel and Staff's arguments suffer from the same methodological flaws. While it is true that the 2012 expense level represents a higher level of expense than other years used in the six-year average, this does not automatically classify it as an anomaly to be excluded. As Public Counsel states, "the use of an average is meant to normalize the costs that may have a high degree of variability from year-to-year."[7] To exclude any amount from the average because it is allegedly "too high" goes against the purpose of using an average in the first place. Arbitrarily removing years or events from the six-year-average calculation denies the Company the opportunity to recover costs of damages from incidents that inevitably arise. The Company contests Public Counsel's and Staff's recommendations to subjectively choose the elements of insurance expense to include in the six-year-average calculation.

The Company's proposal appropriately normalizes the variability in insurance expense over a reasonable period without impairing the Company's ability to recover prudently incurred costs. There is no justifiable reason to further alter this average. Further, Staff's and Public Counsel's positions do not provide a more accurate calculation of costs anticipated in the rate-effective period.

[7] Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 33:21-22 (emphasis added).

In addition, contrary to Public Counsel's assertions, the Company appropriately allocated insurance expense using the System Overhead (SO) factor consistent with the currently approved WCA.

Legal Expenses

Q. Please describe revised adjustment 4.11 (Legal Expenses).

A. It was the Company's intent to exclude all costs related to the Wood Hollow fire in this case. Through discovery, it was determined that certain legal expenses related to Wood Hollow were inadvertently included in the case. As mentioned in the Company's response to Boise data request 8.4, a correction to remove these legal expenses has been made as part of revised adjustment 4.11. The corresponding IHS Global Insight adjustment impact of making this correction is reflected in the Company's revised adjustment 4.13, discussed later in my testimony.

Collection Agency Fees

Q. Did the Company make any revisions to the adjustment for Collection Agency Fees?

A. Yes, as discussed in Ms. Steward's rebuttal testimony, the Company is no longer proposing changes to its approach to recovering collection agency fees. Accordingly, revised adjustment 4.12 (Collection Agency Fees) removes the adjustment from the Company's revenue requirement calculation, resulting in a revenue requirement increase of approximately $44,000.

IHS Global Insight Escalation Adjustment

Q. Is the Company making any modifications to adjustment 4.13 (IHS Global Insight Escalation)?

A. The Company continues to support this adjustment as explained in Mr. R. Bryce Dalley's rebuttal testimony.

A minor change has been made in revised adjustment 4.13 (IHS Global Insight Escalation) to reflect the corresponding change resulting from the legal fees correction discussed earlier in my testimony. The impact of this correction is a reduction of approximately $7,000 in revenue requirement.

NET POWER COSTS

Net Power Cost Update

Q. Please describe the Company's rebuttal adjustment associated with net power costs.

A. As outlined in the rebuttal testimony of Mr. Gregory N. Duvall, the Company has updated net power costs (NPC). These changes are reflected in revised adjustment 5.1.1 (Net Power Costs Pro Forma). This update increases Washington's revenue requirement by approximately $5.7 million.

In addition to the Company's rebuttal update, the pro forma NPC has been revised to reflect the Company's acceptance of Boise's proposed adjustment for the wheeling expenses related to network integration transmission service provided by the Bonneville Power Administration, as discussed in more detail in Mr. Duvall's rebuttal testimony.

Qualifying Facilities

Q. Did the Company update Exhibit No. NCS-7, which was submitted with your initial testimony?

A. Yes. Exhibit No. NCS-12 is an update to Exhibit No. NCS-7. This exhibit provides a summary of the revenue requirement impacts of the Company's primary and alternative proposals for the rate treatment of power purchase agreements with qualifying facilities located in California and Oregon. These proposals are discussed in more detail in Mr. Duvall's direct and rebuttal testimonies.

DEPRECIATION

Q. Did the Company make any revisions to adjustment 6.2?

A. Yes. In the process of calculating rebuttal revenue requirement, the Company identified a formula error in adjustment 6.2 (Depreciation & Amortization Reserve to December 2013 Balances) in the Company's Regulatory Adjustment Model, resulting in an improper allocation of some adjustment balances in the Company's initial filing. Revised adjustment 6.2 corrects for this formulaic error. This correction decreases Washington-allocated rate base by approximately $11.4 million, resulting in a decrease in revenue requirement of approximately $1.3 million.

Q. Did the Company adopt any of the Parties' proposed adjustments to depreciation expense?

A. Yes. Public Counsel proposed an adjustment to reflect the reduced depreciation expense associated with pro forma major plant retirements in determining revenue requirement.[8] For purposes of this case, the Company agrees that this adjustment is appropriate.

[8] Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 17-19.

Public Counsel's adjustment, however, is overstated because it does not take into account the corresponding tax impacts of removing depreciation expense from the test period. Accordingly, the Company developed adjustment 6.5 (Retired Assets Depreciation Expense Removal) to reflect the removal of depreciation expense associated with major plant retirements exceeding $250,000 on a Washington-allocated basis. Including tax impacts, this adjustment decreases Washington revenue requirement by approximately $29,000. This is based on the most recent asset retirement information available.

The Company proposes to update this adjustment in its compliance filing to reflect the depreciation expense impact of actual major plant retirements before the rate effective date to maintain consistency with the Company's proposed treatment of pro forma major plant additions.

INTEREST AND TAXES

Interest True Up

Q. Did the Company make any revisions to adjustment 7.1 (Interest True Up)?

A. Yes. The Company updated adjustment 7.1 (Interest True Up) to incorporate the impacts of the other adjustments included as part of the Company's rebuttal position. No other changes have been made to this adjustment.

Property Taxes

Q. Did any intervening party oppose the Company's pro forma property tax adjustment?

A. Yes. Staff rejects the Company's pro forma adjustment, thereby keeping property tax expense at the accrual level booked during the test year.[9] Mr. Norman K. Ross addresses Staff's concerns in his rebuttal testimony.

Q. Did the Company update or revise its pro forma property tax adjustment?

A. Yes. The Company updated the property tax expense adjustment to reflect booked accruals for the first nine months of the current calendar year (2014) and three months of forecasted property tax expense through December 2014. This update results in a decrease to revenue requirement of approximately $428,000.

Washington Low Income Tax Credit

Q. Please describe the Company's proposed adjustment for the Washington Low Income Tax Credit.

A. In its initial filing, the Company proposed a pro forma adjustment to the historical test period to reflect the most recent credit amount provided by the Washington Department of Revenue. This adjustment is consistent with the Company's past rate case filings and replaces the credit amount booked for the 12-months ended December 31, 2013, with the latest annual approved credit at the of time the Company's initial filing. The credit amount booked during the historical test period (the 12-months ended December 31, 2013) was $262,453.[10] On July 26, 2013, the Company received a letter from the Washington Department of Revenue awarding a credit of $222,651 for the fiscal year ending June 30, 2014.[11] The Company's proposed revenue requirement adjustment therefore reduces the amount of the Washington Low Income Tax Credit by $39,804 to reflect the credit awarded for

[9] Testimony of Jason L. Ball, Exhibit No. JLB-1T at 19.
[10] This amount reflects actual credits recorded for calendar year 2013, which includes $87,882 of actual credits recorded from January 1, 2013, through June 30, 2013, (six months of fiscal year 2013) and $174,572 of actual credits recorded from July 1, 2013, through December 31, 2013, (six months of fiscal year 2014).
[11] Exhibit No. NCS-3, page 7.5.2.

fiscal year 2014, which in turn increases the Company's revenue requirement by approximately the same amount.

Q. Staff rejects the Company's proposed adjustment, arguing that the credit increases each year.[12] Is this argument valid?

A. No. The credit amount available to the Company each year is governed by RCW 82.16.0497, which sets a $2.5 million overall statewide annual limit on the Washington Low Income Credit for all fiscal years after 2007.[13] The Company is one of over fifty electric and gas distribution businesses that annually qualify to receive a share of the $2.5 million. Pacific Power's share varies from year to year.

In July 2014, the Washington Department of Revenue awarded the Company a credit of $165,998 for the fiscal year ending June 30, 2015, a reduction from the $222, 651 awarded for the fiscal year ended June 30, 2014.[14] This demonstrates that the Washington Low Income Credit does not necessarily increase from year to year.

Note that if the Company were to reflect the updated amount of $165,998, the Company's revenue requirement would increase by another $57,000.

Remove Deferred State Tax Expense and Balance

Q. Please describe the Company's update to adjustment 7.7 (Remove Deferred State Tax Expense and Balance).

A. The Company updated adjustment 7.7 to reflect the impact of the Company's rebuttal adjustments to revenue requirement. If additional adjustments proposed by other parties to this case are accepted by the Commission, adjustment 7.7 will need to be updated.

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[12] Testimony of Betty A. Erdahl, Exhibit No. BAE-1T at 5-7.
[13] *See* RCW 82.16.0497(1)(a).
[14] *See* Exhibit No. NCS-16.

RATE BASE ADJUSTMENTS

Pro Forma Major Capital Additions

Q. Please describe the Company's proposed pro forma adjustment for major capital additions.

A. This pro forma adjustment adds to rate base west control area plant additions greater than $250,000 on a Washington-allocated basis that will be placed in service before the rate-effective date.

Q. Is the Company updating its pro forma adjustment for major capital additions in rebuttal?

A. Yes. The Company updated the adjustment to reflect actual costs for projects placed in service through September 30, 2014, the latest month-end close data available when preparing the Company's rebuttal testimony. These amounts are reflected in Exhibit No. NCS-11, page 8.4.2. Projects not in service by September 30, 2014, but expected to be in service before the rate effective date are included in revised adjustment 8.4 and reflect updated costs and in-service dates. In addition, the Company removed the Yale Rock Block Stabilization project from adjustment 8.4 because it is no longer expected to be placed in service before the rate effective date.

At the time of filing this rebuttal testimony, the Company's revised adjustment for pro forma major capital additions decreases revenue requirement by approximately $53,000.

Q. Please describe the Parties' positions on the Company's pro forma adjustment for major capital additions as proposed in the initial filing.

A. Staff supports including pro forma capital additions, but proposes to limit the projects to those that are placed in service at the time of the Company's rebuttal filing.[15] Public Counsel supports including pro forma capital additions to address regulatory lag and rate case frequency, but proposes to limit the adjustment to amounts placed in service as of August 31, 2014.[16] Boise proposes that all pro forma projects be excluded except the Merwin Fish Collector arguing that the Company did not provide sufficient information about 25 of the 30 pro forma capital additions.[17]

Q. What is the Company's response to the Parties' proposals?

A. As discussed in more detail in Mr. Dalley's rebuttal testimony, the Company continues to support the pro forma adjustment for major capital additions proposed in its initial filing. The Company will update pro forma project costs to reflect actual amounts placed in service before the rate effective date in the Company's compliance filing in this case. Thus, the adjustment will reflect only the actual costs of projects that are in service and serving customers by the rate effective date.

Q. Are there any computational problems in Public Counsel's calculations?

A. Yes. In the calculation of the revenue requirement impact of their proposed reduction to pro forma major plant additions adjustment, Public Counsel used the total-company change in depreciation expense rather than the Washington-allocated amount. In doing so, Public Counsel removes too much depreciation expense, which overstates the revenue requirement impact of its proposed adjustment by approximately $479,000.

The deferred tax calculation should also be adjusted. Public Council takes an over-simplified approach by applying the percentage of disallowance to the

[15] Testimony of Betty A. Erdahl, Exhibit No. BAE-1T at 7-9.
[16] Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 12-17.
[17] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 7.

Washington-allocated deferred tax items. This approach does not accurately reflect the deferred tax impact of Public Counsel's proposed reduction on pro forma capital addition amounts.

Q. Does the Company have any concerns with Boise's calculation of its change to the adjustment for pro forma capital additions?

A. Yes. Boise overstates the impact of its adjustment on depreciation expense and accumulated depreciation. Boise uses a ratio of the total Merwin fish collector depreciation to total hydro depreciation expense to determine the amount of depreciation expense and associated reserve to remove from the Company's proposed adjustment. This overstates the adjustment to depreciation expense by approximately $157,000 and to depreciation reserve by approximately $161,000. Boise also takes an over-simplified approach to the deferred tax calculation by taking the ratio of the Washington-allocated Merwin Fish Collector plant addition amounts to the total Washington-allocated plant additions allocated on the Control Area Generation West (CAGW), and applies that percentage to the Washington-allocated deferred tax amounts in the Company's adjustment. Simplifications like these do not properly account for the impact on deferred taxes from the adjustments proposed.

Q. Boise asserts that the Company did not provide sufficient information regarding all of its proposed capital additions. Do you agree?

A. No. The Company's proposed pro forma capital additions were discussed in my initial testimony and exhibits as well as the testimonies of Mr. Richard A. Vail, Mr. Mark R. Tallman and Mr. Dana M. Ralston. The company provided detailed initial testimony on all projects over $1.0 million on a Washington-allocated basis. In addition, the Company responded to numerous data requests regarding the proposed pro forma capital additions, including providing approval documents and other information for every one of the 30 projects in response to Public Counsel data request 53. A copy of the Company's response to Public Counsel data request 53, including attachment 53.1 and a list of all of the documents provided with the response, is provided in Exhibit No. NCS-16.

Q. Did Boise have concerns about specific capital projects?

A. Yes. Boise criticizes the Company's Jim Bridger Unit 1 cooling tower replacement project, the Union Gap substation upgrade, the Selah substation capacity relief project, and the Fry substation project. The three substation projects are addressed in Mr. Vail's direct and rebuttal testimonies. I address Boise's argument regarding the Jim Bridger cooling tower replacement project below.

Q. Please describe and respond to the issues Boise raised regarding the Jim Bridger Unit 1 cooling tower replacement project.

A. Boise claims that the Jim Bridger Unit 1 cooling tower replacement project should be excluded, alleging that cost and timing of the project appear uncertain based on the Company responses to Public Counsel data request 54.[18]

Q. Are Boise's concerns valid?

A. No. The replacement of the Jim Bridger Unit 1 cooling tower was completed and placed in service earlier this year and is now providing service to customers. The costs associated with this project are therefore known and measurable and the project is used and useful in serving Washington customers. There is no uncertainty about the final costs of the project or the project's in service date.

[18] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 12-13.

Boise's position is based on the mistaken premise that the Company's revised response to Public Counsel data request 54 was an *update* when it was actually a correction, as noted in the revised response itself.[19]

Use of End-of-Period Rate Base

Q. Has the Company made any changes to its adjustment to reflect plant in service at end-of-period balances?

A. No. Mr. Dalley addresses the Parties' positions on the use of end-of-period rate base balances in his rebuttal testimony.

Other Rate Base Adjustments

Q. Did the Company make any other rate base adjustments in its revenue requirement calculation?

A. Yes. In preparing the rebuttal revenue requirement, the Company identified an error in adjustment 8.5-8.5.1 (Miscellaneous Rate Base Deductions). Two account balances were not removed from unadjusted results before being added back into rate base through the Investor Supplied Working Capital adjustment. By leaving the balances (which are credits or reductions to rate base) in unadjusted results and including the balances in the Investor Supplied Working Capital adjustment, these balances were included twice in the Company's test period rate base. To remedy this, the Company prepared revised adjustment 8.5 to remove the "Injuries & Damages Provisions" and "Pension & Benefits Provisions" accounts from unadjusted results.

In addition, the Company is correcting adjustment 8.11 (Miscellaneous Asset Sales and Removals). This adjustment was intended to remove from the test period cost items related to assets that have been sold or removed. Through discovery, the

[19] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-4C at 62.

Company determined that it inadvertently removed depreciation expense related to hydro plants still in service. The Company corrects this error in revised adjustment 8.11. This represents an increase in revenue requirement of approximately $379,000.

PRODUCTION FACTOR ADJUSTMENT UPDATE

Q. Please describe any updates to adjustments included in Tab 9.

A. As explained in my direct testimony, the production factor is applied to a selection of pro forma adjustments as a means of adjusting pro forma generation-related components of the revenue requirement to test period expense and balance levels, including pro forma net power costs and pro forma major plant additions. The Company updated the production factor adjustment to reflect changes to the pro forma rebuttal adjustments for net power costs and major plant additions.

TREATMENT OF DEFERRALS

Q. Please provide an overview of the deferral requests that are relevant to this case.

A. In direct testimony, the Company requested to begin amortization of deferrals from the following Dockets: UE-131384—Deferral of Costs Related to Colstrip Outage (Colstrip deferral); UE-132350—Deferral of Reduced Depreciation Expense (depreciation deferral); and UE-140094—Deferral of Costs Related to Declining Hydro Generation (hydro deferral). The Commission consolidated the Colstrip deferral and hydro deferral dockets with this rate case in Order 05. In addition, in Docket UE-140617, the Commission authorized deferral of the revenue requirement associated with the Merwin fish collector and consolidated the docket with this case.

Colstrip Deferral

Q. What are the parties' positions regarding the Company's Colstrip deferred accounting request?

A. Staff recommends recovery of the deferred amounts related to an extended outage at the Colstrip generating plant, but further recommends excluding interest on the deferred amounts and amortizing the deferred amounts through inclusion in base rates (rather than through a separate tariff rider as the Company proposed).[20] Boise disagrees that the costs associated with the Colstrip outage qualify for deferred accounting because the outage was not an extraordinary event.[21] Boise also claims the Company has not provided an updated estimate of the costs incurred and that the costs are not prudent.

Q. How does the Company respond?

A. The prudency of the costs incurred as a result of the Colstrip outage is addressed by Mr. Ralston in his rebuttal testimony. The Colstrip deferral is also addressed in the rebuttal testimony of Mr. Duvall.

Staff's position to remove interest expense does not account for the time value of the money. The deferred amounts represent actual costs incurred by the Company on behalf of its customers. Without interest, the Company will have incurred financing costs related to the deferred amounts that would never be recovered.

The Company also continues to support the use of a separate tariff rather than including the amounts in base rates. This method allows the Company to set the separate tariff rider to zero (or withdraw the tariff) once the deferred amounts are

[20] Testimony of Jason L. Ball, Exhibit No. JLB-1T at 13.
[21] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 62-67.

fully amortized. If the deferrals are included in permanent base rates, the rates will not be changed until the Company's next rate case.

If the Commission decides that the deferred amounts should be included in base rates, a corresponding balance should be reflected in rate base to account for the carrying cost during amortization as shown in Exhibit No. NCS-15. Staff does not recognize this in its proposal.

Boise's claim that the Company has not provided an updated estimate of the replacement power costs referred to in the Company's deferral application is incorrect.[22] The Company provided the actual net power costs in Exhibit No. NCS-9 included in its initial filing. The Company will address Boise's legal arguments that the Colstrip deferral does not meet the Commission's deferral standards in briefing.

Depreciation Deferral

Q. What are the parties' positions regarding the Company's proposal to amortize its depreciation deferral?

A. No party contests the amortization of the depreciation deferral, although Staff reiterates its argument to exclude interest and to amortize the deferred amounts through base rates.[23]

Q. How does the Company respond?

A. For the reasons discussed above, the Company proposes that these amounts be amortized through a separate tariff rider with interest to account for the time value of money. In this case, interest reflects the time value of money for the Company's customers because this deferral is a credit to customers. If the Commission chooses

[22] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 63.
[23] Testimony of Jason L. Ball, Exhibit No. JLB-1T at 13.

to amortize these amounts in base rates, a corresponding balance should be reflected in rate base to account for the carrying costs during amortization (see Exhibit No. NCS-15).

Deferral for Low Hydro Conditions

Q. What are the parties' positions regarding the Company's hydro deferral?

A. Staff rejects the Company's proposal to recover costs deferred as a result of low hydro conditions based on the premise that this would result in dollar-for-dollar recovery of a portion of net power costs.[24] According to Staff, because dollar-for-dollar recovery of net power costs was rejected in the 2013 rate case, the Company's hydro deferral should be rejected. Public Counsel also rejects the deferral, stating that it is not appropriate to defer a select portion of net power cost variances between rate cases.[25] Boise rejects the hydro deferral because it believes hydro conditions in 2014 are "about normal" and the hydro deferral is one-sided.[26]

Q. How does the Company respond?

A. The Company continues to support amortization of its hydro deferral, as further addressed in Mr. Duvall's rebuttal testimony. The revenue requirement in this case has been updated to reflect the most recent net power cost information as shown in Table 1 below.

Merwin Fish Collector Deferral

Q. What are the parties' positions regarding the Company's Merwin deferral?

A. Staff recommends that only a portion of the deferred revenue requirement for the Merwin fish collector be allowed—the deferred operations and maintenance and

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[24] Testimony of David. C. Gomez, Exhibit No. DCG-1CT at 16-18.
[25] Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 42-45.
[26] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 67-68.

depreciation expenses—and that interest on the deferred amounts should not be allowed.[27] Like the other deferrals, Staff recommends amortizing the Merwin deferral through base rates. Public Counsel rejects the Merwin deferral, stating that it is not appropriate to defer revenue requirement of a single project between rate case proceedings.[28] Boise also rejects the Merwin deferral, claiming that allowing recovery of deferred amounts and allowing Merwin in rate base through the pro forma capital additions adjustment would provide double recovery.[29]

Q. How does the Company respond?

A. The Commission's order approving the Merwin deferral (Docket UE-140617) stated that the Company may defer the full revenue requirement associated with the Merwin fish collector for potential future recovery in customer rates, including the *return on* portion of the revenue requirement.[30] Staff claims that limiting the deferral to the *return of* portion of revenue requirement removes an alleged incentive for utilities to use deferred accounting for cost recovery and encourages the use of other ratemaking mechanisms (such as an expedited rate filing) when seeking to add plant additions to rate base.[31]

Staff's proposal to selectively limit a significant portion of the cost associated with this investment is inappropriate and would result in the Company's shareholders absorbing prudently incurred costs to serve its customers. The *return on* investment is a real and quantifiable component of the cost of service and excluding these amounts would not reflect sound ratemaking principles and would be punitive. If

[27] Testimony of Jason L. Ball, Exhibit No. JLB-1T at 13.
[28] Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 45-47.
[29] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 68-71.
[30] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-140762, Order 03 (May 29, 2014).
[31] Testimony of Jason L. Ball, Exhibit No. JLB-1T at 27-28.

Staff proposes to limit the amount that a utility can recover through deferred accounting, it should be done on a basis other than deeming one component of revenue requirement more appropriate for recovery than another.

Public Counsel rejects the Company's proposal to amortize the Merwin deferral because it deems it inappropriate to defer revenue requirement for a capital project between rate cases.[32] Recovery of the Merwin deferral is appropriate, especially given that the project was placed in service very soon after the Company's last general rate case. It is also important to note that no party disputes the prudence of this investment.

Boise's position that recovery of the deferral along with the inclusion of the Merwin project in rate base through the pro forma major capital additions adjustment would result in double recovery is inaccurate.[33] The Merwin deferral tracks the revenue requirement of the project from April 14, 2014 (the date of the deferred accounting petition) until the rate effective date in this case (March 31, 2015). The proposed pro forma capital addition for the Merwin project includes the revenue requirement associated with the project from March 31, 2015, forward. There is therefore no double recovery of Merwin if the Commission allows amortization of the Merwin deferral. If the amortization is not approved, the Company will never recover over $1.7 million in prudently incurred costs.

Q. Please describe Exhibit No. NCS-14.

A. Exhibit No. NCS-14 is an update to Exhibit No. NCS-9, which was included in the Company's initial filing. Exhibit No. NCS-14 is revised to reflect an update to the

[32] Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 45-47.
[33] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 70.

hydro deferral and to remove Colstrip's return on capital component from the Colstrip deferral calculations. Added to the presentation of the summary on Exhibit No. NCS-14, page 1, is the Merwin deferred balance as filed in Docket UE-140617. Interest on the Merwin deferred balance is also included in the accumulated interest calculation. Table 1 below summarizes the requested amortization amounts.

TABLE 1
($ millions)

Description	Requested Amortization
Colstrip Deferral	$1.97
Depreciation Deferral	($0.88)
Hydro Deferral	$2.44
Merwin Deferral	$1.69
Interest	$0.64
Total	**$5.86**

ADDITIONAL REVENUE REQUIREMENT EXHIBIT

Q. Please describe Exhibit No. NCS-13.

A. Exhibit No. NCS-13 details the calculation of rebuttal revenue requirement using the Company's primary cost of capital proposal and alternative scenarios discussed in the testimonies of Mr. Bruce N. Williams and Mr. Kurt G. Strunk.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit No. NCS-11
Docket UE-140762 *et al.*
Witness: Natasha C. Siores

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617** ***(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384** ***(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094** ***(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF NATASHA C. SIORES

**Rebuttal Results of Operations
Twelve-months ended December 31, 2013**

November 2014

THIS EXHIBIT IS VOLUMINOUS AND IS PROVIDED UNDER SEPARATE COVER

Exhibit No. NCS-12
Docket UE-140762 *et al.*
Witness: Natasha C. Siores

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617** ***(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384** ***(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094** ***(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF NATASHA C. SIORES

Summary of Revenue Requirement Scenarios with Net Power Cost QF Alternatives
(Updated)

November 2014

PacifiCorp
Washington General Rate Case - December 2013
Washington Qualified Facilities Scenarios Analysis
Summary of Revenue Requirement Impacts - Rebuttal Position

Net Power Cost Summary

	Total System Net Power Cost	Washington - Allocated Net Power Cost	Washington - Allocated Net Power Cost Production Factor	Washington - Allocated Net Power Cost with Production Factor	
Rebuttal Position	592,723,771	135,614,044	1,048,297	136,662,340	**Ref NCS-11, Page 2.2**
Re-Pricing at WA QFs Avoided Costs	583,799,591	133,556,641	1,032,393	134,589,034	**Ref NCS-12, Page 6**
Load Decrement	527,101,908	125,970,834	931,034	126,901,869	**Ref NCS-12, Page 6**
Situs-Assigned - Excl. OR/CA QFs	550,701,665	126,387,618	976,976	127,364,595	**Ref NCS-12, Page 6**

Revenue Requirement Summary

	Revenue Requirement	Change from Filed	
Rebuttal Position	31,938,957		**Ref NCS-11, Page 1.1**
Re-Pricing at WA QFs Avoided Costs	29,763,224	(2,175,733)	**Ref NCS-12, Page 2**
Load Decrement	28,009,625	(3,929,332)	**Ref NCS-12, Page 3**
Situs-Assigned - Excl. OR/CA QFs	22,181,879	(9,757,079)	**Ref NCS-12, Page 4**

**Note: Revenue Requirement for each alternative is calculated by inputting Net Power Costs as determined by GRID for each scenario into the Company's RAM/JAM models. Net Power Costs for each scenario is summarized on Page 6 of this Exhibit.*

PACIFICORP
WASHINGTON
Re-pricing Oregon/California QFs at Washington Avoided Costs
Normalized Results of Operations - West Control Area
12 Months Ended DECEMBER 2013

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	321,605,659	29,763,224	351,368,883
3	Interdepartmental	-		
4	Special Sales	22,569,946		
5	Other Operating Revenues	7,002,207		
6	Total Operating Revenues	351,177,813		
7				
8	Operating Expenses:			
9	Steam Production	72,172,030		
10	Nuclear Production	-		
11	Hydro Production	7,625,921		
12	Other Power Supply	85,014,766		
13	Transmission	30,999,564		
14	Distribution	12,252,659		
15	Customer Accounting	7,009,444	188,699	7,198,143
16	Customer Service & Info	790,894		
17	Sales	-		
18	Administrative & General	12,342,962		
19	Total O&M Expenses	228,208,239		
20	Depreciation	44,704,303		
21	Amortization	5,116,519		
22	Taxes Other Than Income	21,000,296	1,212,256	22,212,552
23	Income Taxes - Federal	930,828	9,926,794	10,857,622
24	Income Taxes - State	-	-	-
25	Income Taxes - Def Net	5,851,134		
26	Investment Tax Credit Adj.	-		
27	Misc Revenue & Expense	(762,127)		
28	Total Operating Expenses:	305,049,192	11,327,749	316,376,941
29				
30	Operating Rev For Return:	46,128,621	18,435,475	64,564,096
31				
32	Rate Base:			
33	Electric Plant In Service	1,751,865,644		
34	Plant Held for Future Use	234,062		
35	Misc Deferred Debits	8,025,149		
36	Elec Plant Acq Adj	-		
37	Nuclear Fuel	-		
38	Prepayments	(0.00)		
39	Fuel Stock	(0.00)		
40	Material & Supplies	0.00		
41	Working Capital	31,018,483		
42	Weatherization Loans	1,932,316		
43	Misc Rate Base	-		
44	Total Electric Plant:	1,793,075,655	-	1,793,075,655
45				
46	Rate Base Deductions:			
47	Accum Prov For Deprec	(649,561,462)		
48	Accum Prov For Amort	(47,738,217)		
49	Accum Def Income Tax	(246,653,405)		
50	Unamortized ITC	(246,775)		
51	Customer Adv For Const	(488,824)		
52	Customer Service Deposits	(3,361,134)		
53	Misc Rate Base Deductions	(3,253,188)		
54				
55	Total Rate Base Deductions	(951,303,006)	-	(951,303,006)
56				
57	Total Rate Base:	841,772,649	-	841,772,649
58				
59	Return on Rate Base	5.48%		7.67%
60	Return on Equity	5.76%		10.00%
61				
62	TAX CALCULATION:			
63	Operating Revenue	52,910,583	28,362,269	81,272,853
64	Other Deductions			
65	Interest (AFUDC)	(3,560,992)	-	(3,560,992)
66	Interest	21,038,845	-	21,038,845
67	Schedule "M" Additions	64,740,045	-	64,740,045
68	Schedule "M" Deductions	79,836,802	-	79,836,802
69	Income Before Tax	20,335,973	28,362,269	48,698,242
70				
71	State Income Taxes	-	-	-
72	Taxable Income	20,335,973	28,362,269	48,698,242
73				
74	Federal Income Taxes + Other	930,828	9,926,794	10,857,622

This page provides a summary in the same format as Exhibit No.___(NCS-11) Page 1.1 of the impact of the QF scenario referenced and was developed by running the revenue requirement models (RAM and JAM) with the QF scenario. For brevity and ease of comparison, only the Page 1.1 summary is provided, but the full models are available for each scenario run.

PACIFICORP
WASHINGTON
Washington QFs - Load Decrement Approach
Normalized Results of Operations - West Control Area
12 Months Ended DECEMBER 2013

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	321,605,659	28,009,625	349,615,284
3	Interdepartmental	-		
4	Special Sales	23,501,054		
5	Other Operating Revenues	7,337,546		
6	Total Operating Revenues	352,444,259		
7				
8	Operating Expenses:			
9	Steam Production	75,167,006		
10	Nuclear Production	-		
11	Hydro Production	7,942,884		
12	Other Power Supply	75,128,496		
13	Transmission	32,211,460		
14	Distribution	12,252,659		
15	Customer Accounting	7,009,444	177,581	7,187,025
16	Customer Service & Info	790,894		
17	Sales	-		
18	Administrative & General	12,646,769		
19	Total O&M Expenses	223,149,612		
20	Depreciation	45,987,891		
21	Amortization	5,285,266		
22	Taxes Other Than Income	21,246,912	1,140,832	22,387,744
23	Income Taxes - Federal	2,430,763	9,341,924	11,772,687
24	Income Taxes - State	-	-	-
25	Income Taxes - Def Net	5,436,427		
26	Investment Tax Credit Adj.	-		
27	Misc Revenue & Expense	(761,639)		
28	Total Operating Expenses:	302,775,232	10,660,337	313,435,570
29				
30	Operating Rev For Return:	49,669,027	17,349,288	67,018,315
31				
32	Rate Base:			
33	Electric Plant In Service	1,803,338,631		
34	Plant Held for Future Use	238,317		
35	Misc Deferred Debits	8,030,293		
36	Elec Plant Acq Adj	-		
37	Nuclear Fuel	-		
38	Prepayments	(0)		
39	Fuel Stock	(0)		
40	Material & Supplies	0		
41	Working Capital	31,018,483		
42	Weatherization Loans	1,932,307		
43	Misc Rate Base	-		
44	Total Electric Plant:	1,844,558,031	-	1,844,558,031
45				
46	Rate Base Deductions:			
47	Accum Prov For Deprec	(667,348,501)		
48	Accum Prov For Amort	(49,052,417)		
49	Accum Def Income Tax	(246,976,143)		
50	Unamortized ITC	(246,777)		
51	Customer Adv For Const	(489,831)		
52	Customer Service Deposits	(3,361,134)		
53	Misc Rate Base Deductions	(3,312,845)		
54				
55	Total Rate Base Deductions	(970,787,647)	-	(970,787,647)
56				
57	Total Rate Base:	873,770,384	-	873,770,384
58				
59	Return on Rate Base	5.68%		7.67%
60	Return on Equity	6.15%		10.00%
61				
62	TAX CALCULATION:			
63	Operating Revenue	57,536,217	26,691,212	84,227,429
64	Other Deductions			
65	Interest (AFUDC)	(3,670,332)	-	(3,670,332)
66	Interest	21,838,580	-	21,838,580
67	Schedule "M" Additions	66,484,117	-	66,484,117
68	Schedule "M" Deductions	80,493,611	-	80,493,611
69	Income Before Tax	25,358,474	26,691,212	52,049,686
70				
71	State Income Taxes	-	-	-
72	Taxable Income	25,358,474	26,691,212	52,049,686
73				
74	Federal Income Taxes + Other	2,430,763	9,341,924	11,772,687

This page provides a summary in the same format as Exhibit No.___(NCS-11) Page 1.1 of the impact of the QF scenario referenced and was developed by running the revenue requirement models (RAM and JAM) with the QF scenario. For brevity and ease of comparison, only the Page 1.1 summary is provided, but the full models are available for each scenario run.

PACIFICORP
WASHINGTON
Situs-Assigned - Excludes Oregon/California Qualified Facilities
Normalized Results of Operations - West Control Area
12 Months Ended DECEMBER 2013

This page provides a summary in the same format as Exhibit No.___(NCS-11) Page 1.1 of the impact of the QF scenario referenced and was developed by running the revenue requirement models (RAM and JAM) with the QF scenario. For brevity and ease of comparison, only the Page 1.1 summary is provided, but the full models are available for each scenario run.

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	321,605,659	22,181,879	343,787,537
3	Interdepartmental	-		
4	Special Sales	21,907,193		
5	Other Operating Revenues	7,002,207		
6	Total Operating Revenues	350,515,059		
7				
8	Operating Expenses:			
9	Steam Production	73,086,831		
10	Nuclear Production	-		
11	Hydro Production	7,625,921		
12	Other Power Supply	76,212,771		
13	Transmission	30,999,564		
14	Distribution	12,252,659		
15	Customer Accounting	7,009,444	140,633	7,150,077
16	Customer Service & Info	790,894		
17	Sales	-		
18	Administrative & General	12,342,962		
19	Total O&M Expenses	220,321,046		
20	Depreciation	44,704,303		
21	Amortization	5,116,519		
22	Taxes Other Than Income	21,000,296	903,468	21,903,763
23	Income Taxes - Federal	3,459,382	7,398,222	10,857,604
24	Income Taxes - State	-	-	-
25	Income Taxes - Def Net	5,851,134		
26	Investment Tax Credit Adj.	-		
27	Misc Revenue & Expense	(762,127)		
28	Total Operating Expenses:	299,690,552	8,442,323	308,132,875
29				
30	Operating Rev For Return:	50,824,507	13,739,555	64,564,062
31				
32	Rate Base:			
33	Electric Plant In Service	1,751,865,644		
34	Plant Held for Future Use	234,062		
35	Misc Deferred Debits	8,025,149		
36	Elec Plant Acq Adj	-		
37	Nuclear Fuel	-		
38	Prepayments	(0)		
39	Fuel Stock	(0)		
40	Material & Supplies	0		
41	Working Capital	31,018,483		
42	Weatherization Loans	1,932,316		
43	Misc Rate Base	-		
44	Total Electric Plant:	1,793,075,655	-	1,793,075,655
45				
46	Rate Base Deductions:			
47	Accum Prov For Deprec	(649,561,462)		
48	Accum Prov For Amort	(47,738,217)		
49	Accum Def Income Tax	(246,653,405)		
50	Unamortized ITC	(246,775)		
51	Customer Adv For Const	(488,824)		
52	Customer Service Deposits	(3,361,134)		
53	Misc Rate Base Deductions	(3,253,188)		
54				
55	Total Rate Base Deductions	(951,303,006)	-	(951,303,006)
56				
57	Total Rate Base:	841,772,649	-	841,772,649
58				
59	Return on Rate Base	6.04%		7.67%
60	Return on Equity	6.84%		10.00%
61				
62	TAX CALCULATION:			
63	Operating Revenue	60,135,023	21,137,778	81,272,800
64	Other Deductions			
65	Interest (AFUDC)	(3,560,992)	-	(3,560,992)
66	Interest	21,038,845	-	21,038,845
67	Schedule "M" Additions	64,740,045	-	64,740,045
68	Schedule "M" Deductions	79,836,802	-	79,836,802
69	Income Before Tax	27,560,412	21,137,778	48,698,189
70				
71	State Income Taxes	-	-	-
72	Taxable Income	27,560,412	21,137,778	48,698,189
73				
74	Federal Income Taxes + Other	3,459,382	7,398,222	10,857,604

PacifiCorp
Washington General Rate Case - December 2013
Washington Qualified Facilities Scenarios Analysis
Impact on WA Allocation Factors with Decremented Loads

Revenue Requirement Impact - Load Decrement	
Requested Rev. Req.	31,938,957
Load Impact	(3,929,332)
Updated Rev. Req	**28,009,625**

Washington Allocation Factors				
DESCRIPTION	**FACTOR**	**Requested**	**QF Load Decrement**	**Change**
System Generation	SG	7.9057%	7.9313%	0.0256%
System Capacity	SC	8.0177%	8.0177%	-
System Energy	SE	7.5698%	7.6721%	0.1023%
Control Area Energy - West	CAEW	22.7414%	23.6903%	0.9489%
System Overhead	SO	6.8539%	7.0538%	0.1999%
System Net Plant	SNP	6.2207%	6.4117%	0.1910%
Control Area Generation - West	CAGW	23.0849%	24.0433%	0.9584%
Jim Bridger Generation	JBG	22.9539%	23.9069%	0.9530%
Jim Bridger Energy	JBE	22.6123%	23.5559%	0.9436%

WCA Energy Impact				
	California	Oregon	Washington	Total
Total Energy	890,647	14,305,867	4,473,152	19,669,666
QF Load Decrement	(59,856)	(728,040)	-	(787,896)
Decrement as Percentage of Total Energy	*6.7205%*	*5.0891%*	-	
Total	830,791	13,577,827	4,473,152	18,881,770

WCA Capacity Impact				
	California	Oregon	Washington	Total
Requested Position	1,623	26,851	8,601	37,075
Load Decrement	(109)	(1,366)	-	(1,476)
Decrement as Percentage of Capacity	*6.7205%*	*5.0891%*	-	
Total	1,514	25,484	8,601	35,599

PacifiCorp
Washington General Rate Case - December 2013
Washington Qualified Facilities Scenarios Analysis
Comparison of Net Power Costs - West Control Area

		Allocation Factors As Filed		Rebuttal PRO FORMA NPC 12 Months Ended March 2016		Re-Pricing at WA Avoided Costs PRO FORMA NPC 12 Months Ended March 2016		Situs-Assigned - Excl. OR/CA QFs PRO FORMA NPC 12 Months Ended March 2016		Allocation Factors Load Decremented		Load Decrement PRO FORMA NPC 12 Months Ending December 2013	
Description	**FERC Account**	**WCA Alloc. Factor**	**WA Alloc. %**	**Total West Control Area**	**Washington Allocated**	**Total West Control Area**	**Washington Allocated**	**Total West Control Area**	**Washington Allocated**			**Total West Control Area**	**Washington Allocated**
Sales for Resale (Account 447)													
Existing Firm Sales - Pacific	447NPC	CAGW	23.0849%	-	-	-	-	-	-	CAGW	24.0433%	-	-
Post-Merger Firm Sales	447NPC	CAGW	23.0849%	97,019,406	22,396,819	97,019,406	22,396,819	94,170,486	21,739,149	CAGW	24.0433%	97,019,406	23,326,672
Non-Firm Sales	447NPC	CAEW	22.7414%	-	-	-	-	-	-	CAEW	23.6903%	-	-
Total Sales for Resale				97,019,406	22,396,819	97,019,406	22,396,819	94,170,486	21,739,149			97,019,406	23,326,672
Purchased Power (Account 555)													
Existing Firm Demand - Pacific	555NPC	CAGW	23.0849%	3,495,730	806,985	3,332,350	769,269	761,861	175,875	CAGW	24.0433%	761,861	183,177
Existing Firm Energy	555NPC	CAEW	22.7414%	15,170,063	3,449,881	14,374,052	3,268,857	1,850,255	420,773	CAEW	23.6903%	1,850,255	438,331
WCA Qualifying Facilities	555NPC	CAGW	23.0849%	50,147,686	11,576,536	42,182,897	9,737,873	-	-	CAGW	24.0433%	-	-
WA Qualifying Facilities	555NPC	WA	100.0000%	-	-	-	-	579,500	579,500	WA	100.0000%	579,500	579,500
Post-Merger Firm Energy	555NPC	CAGW	23.0849%	172,213,714	39,755,339	172,213,714	39,755,339	188,044,459	43,409,848	CAGW	24.0433%	172,213,714	41,405,869
Other Generation Expenses	555NPC	CAGW	23.0849%	1,101,940	254,382	1,101,940	254,382	1,029,918	237,755	CAGW	24.0433%	1,101,940	264,943
Total Purchased Power				242,129,133	55,843,122	233,204,953	53,785,720	192,265,994	44,823,752			176,507,270	42,871,820
Wheeling (Account 565)													
Existing Firm - Pacific	565NPC	CAGW	23.0849%	25,004,656	5,772,296	25,004,656	5,772,296	25,004,656	5,772,296	CAGW	24.0433%	25,004,656	6,011,946
Post Merger Firm	565NPC	CAGW	23.0849%	83,917,357	19,372,226	83,917,357	19,372,226	83,917,357	19,372,226	CAGW	24.0433%	83,917,357	20,176,506
Non Firm	565NPC	CAEW	22.7414%	-	-	-	-	-	-	CAEW	23.6903%	-	-
Total Wheeling Expense				108,922,013	25,144,522	108,922,013	25,144,522	108,922,013	25,144,522			108,922,013	26,188,452
Fuel Expense (Accounts 501 and 547)													
Fuel Consumed - Coal	501NPC	CAEW	22.7414%	247,320,762	56,244,137	247,320,762	56,244,137	251,312,536	57,151,921	CAEW	23.6903%	247,320,762	58,591,086
Fuel Consumed - Natural Gas	547NPC	CAEW	22.7414%	91,371,270	20,779,081	91,371,270	20,779,081	92,371,608	21,006,572	CAEW	23.6903%	91,371,270	21,646,148
Total Fuel and Other Expense				338,692,032	77,023,218	338,692,032	77,023,218	343,684,144	78,158,493			338,692,032	80,237,234
Total Net Power Costs				**592,723,771**	135,614,044	**583,799,591**	133,556,641	**550,701,665**	126,387,618			**527,101,908**	125,970,834
Production Factor Adjustment					1,048,297		1,032,393		976,976				931,034
Net WA-Allocated Net Power Cost					**136,662,340**		**134,589,034**		**127,364,595**				**126,901,869**
					Ref. NCS-11 Page 2.2		Ref. NCS-12 Page 1		Ref. NCS-12 Page 1				Ref. NCS-12 Page 1

Exhibit No. NCS-13
Docket UE-140762 *et al.*
Witness: Natasha C. Siores

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617** ***(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384** ***(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094** ***(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF NATASHA C. SIORES

Summary of Revenue Requirement Scenario with Alternative Capital Structure (Updated)

November 2014

PacifiCorp
Washington General Rate Case - December 2013
Hypothetical Capital Structure Analysis
Summary of Revenue Requirement Impacts - Rebuttal Position

Capital Structure and Cost - As Filed (Ref Exhibit NCS-3, Page 2.1)

	Capital Structure	Embedded Cost	Weighted Cost
Short-Term Debt	0.19%	1.73%	0.00%
Long-Term Debt	48.06%	5.19%	2.50%
Preferred Stock	0.02%	6.75%	0.00%
Common Equity	51.73%	10.00%	5.17%
Total	100.00%		7.67%

Capital Structure and Cost - Alternative (Ref BNW-1T, Page 13)

	Capital Structure	Embedded Cost	Weighted Cost
Short-Term Debt	0.19%	2.11%	0.00%
Long-Term Debt	50.69%	5.80%	2.94%
Preferred Stock	0.02%	6.75%	0.00%
Common Equity	49.10%	10.28%	5.05%
Total	100.00%		7.99%

Revenue Requirement Summary

	Revenue Requirement	Change from Filed	
Rebuttal Position	31,938,957		**Ref NCS-11, Page 1.1**
Hypothetical Capital Structure	34,163,516	2,224,559	**Ref NCS-13 Page 2**

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WASHINGTON
Normalized Results of Operations - West Control Area
12 Months Ended DECEMBER 2013

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	**Operating Revenues:**			
2	General Business Revenues	321,605,659	34,163,516	355,769,175
3	Interdepartmental	-		
4	Special Sales	22,569,946		
5	Other Operating Revenues	7,002,207		
6	Total Operating Revenues	351,177,813		
7				
8	Operating Expenses:			
9	Steam Production	72,172,030		
10	Nuclear Production	-		
11	Hydro Production	7,625,921		
12	Other Power Supply	87,088,072		
13	Transmission	30,999,564		
14	Distribution	12,252,659		
15	Customer Accounting	7,009,444	216,597	7,226,041
16	Customer Service & Info	790,894		
17	Sales	-		
18	Administrative & General	12,342,962		
19	Total O&M Expenses	230,281,545		
20	Depreciation	44,704,303		
21	Amortization	5,116,519		
22	Taxes Other Than Income	21,000,296	1,391,480	22,391,776
23	Income Taxes - Federal	(1,110,610)	11,394,404	10,283,794
24	Income Taxes - State	-	-	-
25	Income Taxes - Def Net	5,851,134		
26	Investment Tax Credit Adj.	-		
27	Misc Revenue & Expense	(762,127)		
28	Total Operating Expenses:	305,081,060	13,002,481	318,083,540
29				
30	Operating Rev For Return:	46,096,753	21,161,036	67,257,788
31				
32	Rate Base:			
33	Electric Plant In Service	1,751,865,644		
34	Plant Held for Future Use	234,062		
35	Misc Deferred Debits	8,025,149		
36	Elec Plant Acq Adj	-		
37	Nuclear Fuel	-		
38	Prepayments	(0)		
39	Fuel Stock	(0)		
40	Material & Supplies	0		
41	Working Capital	31,018,483		
42	Weatherization Loans	1,932,316		
43	Misc Rate Base	-		
44	Total Electric Plant:	1,793,075,655	-	1,793,075,655
45				
46	Rate Base Deductions:			
47	Accum Prov For Deprec	(649,561,462)		
48	Accum Prov For Amort	(47,738,217)		
49	Accum Def Income Tax	(246,653,405)		
50	Unamortized ITC	(246,775)		
51	Customer Adv For Const	(488,824)		
52	Customer Service Deposits	(3,361,134)		
53	Misc Rate Base Deductions	(3,253,188)		
54				
55	Total Rate Base Deductions	(951,303,006)	-	(951,303,006)
56				
57	Total Rate Base:	841,772,649	-	841,772,649
58				
59	Return on Rate Base	0		0
60	Return on Equity	0		0
61				
62	TAX CALCULATION:			
63	Operating Revenue	50,837,277	32,555,439	83,392,717
64	Other Deductions			
65	Interest (AFUDC)	(3,560,992)	-	(3,560,992)
66	Interest	24,798,218	-	24,798,218
67	Schedule "M" Additions	64,740,045	-	64,740,045
68	Schedule "M" Deductions	79,836,802	-	79,836,802
69	Income Before Tax	14,503,293	32,555,439	47,058,732
70				
71	State Income Taxes	-	-	-
72	Taxable Income	14,503,293	32,555,439	47,058,732
73				
74	Federal Income Taxes + Other	(1,110,610)	11,394,404	10,283,794

This page provides a summary in the same format as Exhibit No.___(NCS-11) page 1.1 of the impact of the capital structure scenario referenced and was developed by running the revenue requirement models (RAM and JAM) with the capital structure scenario. For brevity and ease of comparison, only the page 1.1 summary is provided, but the full models are available for each scenario run.

Exhibit No. NCS-14
Docket UE-140762 *et al.*
Witness: Natasha C. Siores

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617** ***(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384** ***(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094** ***(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF NATASHA C. SIORES

Summary and Calculation of Deferred Amounts Requested (Updated)

November 2014

PacifiCorp
Washington General Rate Case - December 2013
Request to Amortize Deferred Amounts - Updated
Summary of Deferred Amounts ($s)

	Amount to Amortize	
Colstrip Deferral - UE-131384	1,970,690	Ref Page 2
Depreciation Deferral - UE-132350	(877,345)	Ref Page 3
Hydro Deferral - UE-140094	2,437,932	Ref Page 4
Merwin Deferral - UE-140617	1,687,565	Ref Page 5
Accumulated Interest	637,494	Ref Page 2 - 5
Total	**5,856,337**	

PacifiCorp
Washington General Rate Case - December 2013
UE-131389 - Colstrip Deferral Amortization Schedule

Month	Beginning Balance	Additions[1]	Interest Rate[2]	Interest	Amortization	Ending Balance
Jul-13	-	57,884	7.743%	187	-	58,071
Aug-13	58,071	274,501	7.743%	1,260	-	333,832
Sep-13	333,832	301,708	7.743%	3,127	-	638,667
Oct-13	638,667	305,271	7.743%	5,106	-	949,043
Nov-13	949,043	299,807	7.743%	7,091	-	1,255,941
Dec-13	1,255,941	158,619	7.358%	8,187	-	1,422,746
Jan-14	1,422,746	332,871	7.358%	9,744	-	1,765,361
Feb-14	1,765,361	240,030	7.358%	11,560	-	2,016,951
Mar-14	2,016,951	-	7.358%	12,366	-	2,029,317
Apr-14	2,029,317	-	7.358%	12,442	-	2,041,760
May-14	2,041,760	-	7.358%	12,519	-	2,054,278
Jun-14	2,054,278	-	7.358%	12,595	-	2,066,874
Jul-14	2,066,874	-	7.358%	12,673	-	2,079,546
Aug-14	2,079,546	-	7.358%	12,750	-	2,092,296
Sep-14	2,092,296	-	7.358%	12,828	-	2,105,125
Oct-14	2,105,125	-	7.358%	12,907	-	2,118,032
Nov-14	2,118,032	-	7.358%	12,986	-	2,131,018
Dec-14	2,131,018	-	7.358%	13,066	-	2,144,084
Jan-15	2,144,084	-	7.358%	13,146	-	2,157,230
Feb-15	2,157,230	-	7.358%	13,227	-	2,170,456
Mar-15	2,170,456	-	7.358%	13,308	-	2,183,764
Apr-15	2,183,764	-	7.674%	13,965	(189,080)	2,008,648
May-15	2,008,648	-	7.674%	12,240	(189,080)	1,831,808
Jun-15	1,831,808	-	7.674%	11,109	(189,080)	1,653,837
Jul-15	1,653,837	-	7.674%	9,971	(189,080)	1,474,727
Aug-15	1,474,727	-	7.674%	8,826	(189,080)	1,294,473
Sep-15	1,294,473	-	7.674%	7,673	(189,080)	1,113,066
Oct-15	1,113,066	-	7.674%	6,513	(189,080)	930,498
Nov-15	930,498	-	7.674%	5,346	(189,080)	746,764
Dec-15	746,764	-	7.674%	4,171	(189,080)	561,854
Jan-16	561,854	-	7.674%	2,988	(189,080)	375,762
Feb-16	375,762	-	7.674%	1,798	(189,080)	188,480
Mar-16	188,480	-	7.674%	601	(189,080)	-
Total		**1,970,690**		**298,275**	**(2,268,966)**	
		Ref Page 1		**Ref Page 1**		

Note 1 - Additions amount per Company's initial filing Exhibit No.__(NCS-9), Page 5

Note 2 - For details on Interest Rate, please refer to Page 9

PacifiCorp
Washington General Rate Case - December 2013
UE-132350 - Depreciation Deferral Amortization Schedule

Month	Beginning Balance	Additions	Interest Rate[1]	Interest	Amortization	Ending Balance
Jan-14	-	(58,490)	7.358%	(179)	-	(58,669)
Feb-14	(58,669)	(58,490)	7.358%	(539)	-	(117,698)
Mar-14	(117,698)	(58,490)	7.358%	(901)	-	(177,088)
Apr-14	(177,088)	(58,490)	7.358%	(1,265)	-	(236,843)
May-14	(236,843)	(58,490)	7.358%	(1,631)	-	(296,964)
Jun-14	(296,964)	(58,490)	7.358%	(2,000)	-	(357,454)
Jul-14	(357,454)	(58,490)	7.358%	(2,371)	-	(418,314)
Aug-14	(418,314)	(58,490)	7.358%	(2,744)	-	(479,548)
Sep-14	(479,548)	(58,490)	7.358%	(3,120)	-	(541,157)
Oct-14	(541,157)	(58,490)	7.358%	(3,497)	-	(603,144)
Nov-14	(603,144)	(58,490)	7.358%	(3,877)	-	(665,511)
Dec-14	(665,511)	(58,490)	7.358%	(4,260)	-	(728,261)
Jan-15	(728,261)	(58,490)	7.358%	(4,644)	-	(791,395)
Feb-15	(791,395)	(58,490)	7.358%	(5,032)	-	(854,916)
Mar-15	(854,916)	(58,490)	7.358%	(5,421)	-	(918,827)
Apr-15	(918,827)	-	7.674%	(5,876)	79,556	(845,146)
May-15	(845,146)	-	7.674%	(5,150)	79,556	(770,740)
Jun-15	(770,740)	-	7.674%	(4,674)	79,556	(695,858)
Jul-15	(695,858)	-	7.674%	(4,195)	79,556	(620,497)
Aug-15	(620,497)	-	7.674%	(3,714)	79,556	(544,654)
Sep-15	(544,654)	-	7.674%	(3,229)	79,556	(468,326)
Oct-15	(468,326)	-	7.674%	(2,740)	79,556	(391,511)
Nov-15	(391,511)	-	7.674%	(2,249)	79,556	(314,204)
Dec-15	(314,204)	-	7.674%	(1,755)	79,556	(236,402)
Jan-16	(236,402)	-	7.674%	(1,257)	79,556	(158,103)
Feb-16	(158,103)	-	7.674%	(757)	79,556	(79,304)
Mar-16	(79,304)	-	7.674%	(253)	79,556	-
		(877,345)		**(77,331)**	**954,676**	
		Ref Page 1		**Ref Page 1**		

Note 1 - Additions per Company's initial filing Exhibit No.__(NCS-9), Page 7

Note 2 - For details on Interest Rate, please refer to Page 9

PacifiCorp
Washington General Rate Case - December 2013
UE-140094 - Hydro Deferral - Replacement Power Cost

Month	Beginning Balance	Additions[1]	Interest Rate[2]	Interest	Amortization	Ending Balance
Jan-14	-	747,342	7.358%	2,291	-	749,634
Feb-14	749,634	301,083	7.358%	5,519	-	1,056,236
Mar-14	1,056,236	(284,324)	7.358%	5,604	-	777,516
Apr-14	777,516	(116,112)	7.358%	4,411	-	665,815
May-14	665,815	(336,050)	7.358%	3,052	-	332,817
Jun-14	332,817	457,795	7.358%	3,444	-	794,056
Jul-14	794,056	202,228	7.358%	5,489	-	1,001,772
Aug-14	1,001,772	78,091	7.358%	6,382	-	1,086,245
Sep-14	1,086,245	759,848	7.358%	8,989	-	1,855,083
Oct-14	1,855,083	(361,558)	7.358%	10,266	-	1,503,791
Nov-14	1,503,791	719,423	7.358%	11,426	-	2,234,639
Dec-14	2,234,639	270,165	7.358%	14,529	-	2,519,334
Jan-15	2,519,334	-	7.358%	15,447	-	2,534,780
Feb-15	2,534,780	-	7.358%	15,541	-	2,550,322
Mar-15	2,550,322	-	7.358%	15,637	-	2,565,958
Apr-15	2,565,958	-	7.674%	16,409	(222,173)	2,360,194
May-15	2,360,194	-	7.674%	14,382	(222,173)	2,152,404
Jun-15	2,152,404	-	7.674%	13,054	(222,173)	1,943,285
Jul-15	1,943,285	-	7.674%	11,716	(222,173)	1,732,829
Aug-15	1,732,829	-	7.674%	10,371	(222,173)	1,521,027
Sep-15	1,521,027	-	7.674%	9,016	(222,173)	1,307,871
Oct-15	1,307,871	-	7.674%	7,653	(222,173)	1,093,351
Nov-15	1,093,351	-	7.674%	6,281	(222,173)	877,460
Dec-15	877,460	-	7.674%	4,901	(222,173)	660,188
Jan-16	660,188	-	7.674%	3,511	(222,173)	441,526
Feb-16	441,526	-	7.674%	2,113	(222,173)	221,467
Mar-16	221,467	-	7.674%	706	(222,173)	-
Total		**2,437,932**		**228,140**	**(2,666,072)**	
		Ref Page 1		**Ref Page 1**		

Note 1 - Updated Replacement Power Costs per Company's 5th supplemental response to data request PC 2 in Docket UE-140094
Grossed up for Revenue Sensitive Items
Note 2 - For details on Interest Rate, please refer to Page 9

PacifiCorp
Washington General Rate Case - December 2013
UE-140617 - Merwin Fish Collector Amortization Schedule

Month	Beginning Balance	Return on Rate Base[1]	O&M Expense[2]	Depreciation Expense[3]	Interest Rate[4]	Interest	Amortization	Ending Balance
Mar-14	-	1,158,253	-	18,808	7.358%	3,608		1,180,669
Apr-14	1,180,669		4,493	37,616	7.358%	7,368		1,230,145
May-14	1,230,145		4,493	37,616	7.358%	7,671		1,279,925
Jun-14	1,279,925		4,493	37,616	7.358%	7,977		1,330,010
Jul-14	1,330,010		4,493	37,616	7.358%	8,284		1,380,403
Aug-14	1,380,403		7,094	37,616	7.358%	8,601		1,433,713
Sep-14	1,433,713		7,094	37,616	7.358%	8,928		1,487,350
Oct-14	1,487,350		4,493	37,616	7.358%	9,248		1,538,707
Nov-14	1,538,707		4,493	37,616	7.358%	9,563		1,590,379
Dec-14	1,590,379		4,493	37,616	7.358%	9,880		1,642,368
Jan-15	1,642,368		4,493	37,616	7.358%	10,199		1,694,675
Feb-15	1,694,675		4,493	37,616	7.358%	10,520		1,747,303
Mar-15	1,747,303		4,493	37,616	7.358%	10,842		1,800,254
Apr-15	1,800,254		-	-	7.674%	11,512	(156,291)	1,655,475
May-15	1,655,475		-	-	7.674%	10,586	(156,291)	1,509,771
Jun-15	1,509,771		-	-	7.674%	9,655	(156,291)	1,363,135
Jul-15	1,363,135		-	-	7.674%	8,717	(156,291)	1,215,561
Aug-15	1,215,561		-	-	7.674%	7,773	(156,291)	1,067,044
Sep-15	1,067,044		-	-	7.674%	6,823	(156,291)	917,576
Oct-15	917,576		-	-	7.674%	5,868	(156,291)	767,153
Nov-15	767,153		-	-	7.674%	4,906	(156,291)	615,768
Dec-15	615,768		-	-	7.674%	3,938	(156,291)	463,415
Jan-16	463,415		-	-	7.674%	2,963	(156,291)	310,088
Feb-16	310,088		-	-	7.674%	1,983	(156,291)	155,780
Mar-16	155,780		-	-	7.674%	996	(156,291)	486
Total		**1,158,253**	**59,117**	**470,195**		**188,409**	**(1,875,489)**	
		Ref Page 1	**Ref Page 1**	**Ref Page 1**		**Ref Page 1**		

Note 1 - For detailed Return on Rate Base Calculation, please refer to Page 6

PacifiCorp
Washington General Rate Case - December 2013
Return on Rate Base Calculation - Merwin Deferral

Return on Rate Base[1]

Capital Investment (in service March 2014)	58,369,301	
Accumulated Depreciation (through March 2015)	(1,033,973)	
Accumulated DIT Balance	(7,745,755)	
Net Rate Base	49,589,574	
Pre-Tax Return from UE-130043	9.88%	Ref Page 9
Pre-Tax Return on Rate Base	4,898,132	
Factor - CAGW from UE-130043	22.5336%	Ref Page 9
Rev Req - Return on Rate Base before Revenue Sensitive Items	1,103,724	
Revenue Sensitive Items	54,528	
WA Revenue Requirement - Return on Rate Base	**1,158,253**	Ref Page 5

Note 1 - Amounts used to calculate Return on Rate Base are taken from Docket No. UE-140617, Attachment F, Page 1 of 6

PacifiCorp
Washington General Rate Case - December 2013
Depreciation Expense Calculation - Merwin Deferral

In-Service Date	Mar-14	**CAGW Factor**	**Revn Sensitive**
Depreciation Rate	3.270%	22.5336%	4.9404%

		TOTAL COMPANY				WA Allocated	
		Plant in Service	**Accumulated Depreciation [1]**	**Depreciation Expense[1]**	**ADIT**	**Depreciation Expense**	**Adj. Depreciation Expense**
CY 2014	Jan-14	-	-	-		-	
	Feb-14	-	-	-		-	
	Mar-14	58,369,301	(79,536)	79,536		17,922	18,808
	Apr-14	58,369,301	(238,609)	159,073		35,845	37,616
	May-14	58,369,301	(397,682)	159,073		35,845	37,616
	Jun-14	58,369,301	(556,754)	159,073		35,845	37,616
	Jul-14	58,369,301	(715,827)	159,073		35,845	37,616
	Aug-14	58,369,301	(874,900)	159,073		35,845	37,616
	Sep-14	58,369,301	(1,033,973)	159,073		35,845	37,616
	Oct-14	58,369,301	(1,193,045)	159,073		35,845	37,616
	Nov-14	58,369,301	(1,352,118)	159,073		35,845	37,616
	Dec-14	58,369,301	(1,511,191)	159,073		35,845	37,616
	2014 Ending Bal.	**58,369,301**	**(1,511,191)**	**1,511,191**		**340,525**	**357,349**
						-	
CY 2015	Jan-15	58,369,301	(1,670,263)	159,073		35,845	37,616
	Feb-15	58,369,301	(1,829,336)	159,073		35,845	37,616
	Mar-15	58,369,301	(1,988,409)	159,073		35,845	37,616
	Apr-15	58,369,301	(2,147,482)	159,073		35,845	37,616
	May-15	58,369,301	(2,306,554)	159,073		35,845	37,616
	Jun-15	58,369,301	(2,465,627)	159,073		35,845	37,616
	Jul-15	58,369,301	(2,624,700)	159,073		35,845	37,616
	Aug-15	58,369,301	(2,783,772)	159,073		35,845	37,616
	Sep-15	58,369,301	(2,942,845)	159,073		35,845	37,616
	Oct-15	58,369,301	(3,101,918)	159,073		35,845	37,616
	Nov-15	58,369,301	(3,260,990)	159,073		35,845	37,616
	Dec-15	58,369,301	(3,420,063)	159,073		35,845	37,616
	2015 Ending Bal.	**58,369,301**	**(3,420,063)**	**1,908,872**		**430,137**	**451,388**
	AMA (Mar 2014 to Mar 2015)	**58,369,301**	**(1,033,973)**	**1,908,872**	**(7,745,755)**	**448,060**	**470,195**
							Ref Page 5

Note 1 - Accumulatd Depreciation and Depreciation Expense amounts are taken from Docket No. UE-140617, Attachment F, Page 3 of 6

PacifiCorp
Washington General Rate Case - December 2013
Operations & Maintenance Expense Calculation - Merwin Deferral

	TOTAL COMPANY												
O&M Costs[1]	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Total 12 Months**
Merwin Fish Collector	$ 19,000	$ 19,000	$ 19,000	$ 19,000	$ 30,000	$ 30,000	$ 19,000	$ 19,000	$ 19,000	$ 19,000	$ 19,000	$ 19,000	**$ 250,000**

CAGW FACTOR 22.5336%

	WASHINGTON ALLOCATED												
O&M Costs	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Total 12 Months**
Merwin Fish Collector	$ 4,281	$ 4,281	$ 4,281	$ 4,281	$ 6,760	$ 6,760	$ 4,281	$ 4,281	$ 4,281	$ 4,281	$ 4,281	$ 4,281	$ 56,334
Revenue Sensitive	$ 212	$ 212	$ 212	$ 212	$ 334	$ 334	$ 212	$ 212	$ 212	$ 212	$ 212	$ 212	$ 2,768
Total O&M Costs	**$ 4,493**	**$ 4,493**	**$ 4,493**	**$ 4,493**	**$ 7,094**	**$ 7,094**	**$ 4,493**	**$ 4,493**	**$ 4,493**	**$ 4,493**	**$ 4,493**	**$ 4,493**	**59,102**
													Ref Page 5

Note 1 - O&M Expense amounts are taken from Docket No. UE-140617, Attachment F, Page 5 of 6

PacifiCorp
Washington General Rate Case - December 2013
Deferrals for Colstrip Outage, Hydro, and Depreciation
Effective cost of capital and factors during deferral and amortization periods
Taken from Exhibit No.__(NCS-9), Page 8

Capital Cost and Structure Requested in UE-140762

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	48.25%	5.18%	2.499%		2.50%
Preferred	0.02%	6.75%	0.001%	153.85%	0.00%
Common	51.73%	10.00%	5.173%	153.85%	7.96%
Total	100.00%		7.67%		10.46%
Merged Effective Tax Rate					35.000%
Pre-Tax Bump-up Factor					153.85%
Revenue Sensitive Items - UE140762					
WUTC Regulatory Fee			0.200%	0.210%	
Bad Debt Percentage			0.611%	0.641%	
Revenue Tax			3.873%	4.063%	
WCA Allocation Factors - UE 140762					
Washington CAGW Factor			23.0849%		
Washington CAEW Factor			22.7414%		

Capital Cost and Structure Ordered from UE-130043

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	50.62%	5.29%	2.678%		2.68%
Preferred	0.28%	5.43%	0.015%	153.85%	0.02%
Common	49.10%	9.50%	4.665%	153.85%	7.18%
Total	100.00%		7.36%		9.88%
Merged Effective Tax Rate					35.000%
Pre-Tax Bump-up Factor					153.85%
Revenue Sensitive Items - UE 130043					
WUTC Regulatory Fee			0.200%	0.210%	
Bad Debt Percentage			0.660%	0.693%	
Revenue Tax			3.848%	4.038%	
WCA Allocation Factors - UE 130043					
Washington CAGW Factor			22.5336%		
Washington CAEW Factor			22.6481%		

Capital Cost and Structure Ordered from UE-111190

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	50.60%	5.76%	2.915%		2.91%
Preferred	0.30%	5.43%	0.016%	153.85%	0.03%
Common	49.10%	9.80%	4.812%	153.85%	7.40%
Total	100.00%		7.74%		10.34%
Merged Effective Tax Rate					35.000%
Pre-Tax Bump-up Factor					153.85%
Revenue Sensitive Items - UE 111190					
WUTC Regulatory Fee			0.200%	0.210%	
Bad Debt Percentage			0.507%	0.531%	
Revenue Tax			3.873%	4.059%	
WCA Allocation Factors - UE 111190					
Washington CAGW Factor			22.4742%		
Washington CAEW Factor			22.3245%		

Exhibit No. NCS-15
Docket UE-140762 *et al.*
Witness: Natasha C. Siores

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

<table>
<tr><td>WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY,

Respondent.</td><td>DOCKETS UE-140762 and UE-140617 (consolidated)</td></tr>
<tr><td>In the Matter of the Petition of

PACIFIC POWER & LIGHT COMPANY,

For an Order Approving Deferral of Costs Related to Colstrip Outage.</td><td>DOCKET UE-131384 (consolidated)</td></tr>
<tr><td>In the Matter of the Petition of

PACIFIC POWER & LIGHT COMPANY,

For an Order Approving Deferral of Costs Related to Declining Hydro Generation.</td><td>DOCKET UE-140094 (consolidated)</td></tr>
</table>

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF NATASHA C. SIORES

Summary and Calculation of Deferred Amounts Requested
(Hypothetical Amortization into Base Rates)

November 2014

PacifiCorp
Washington General Rate Case - December 2013
Amortization of Deferred Amounts in Base Rates
Summary of Deferred Amounts ($s)

	Deferral Amount	Interest	Amount to Amortize	Addition to Rate Base	Revenue Requirement	
Colstrip Deferral - UE-131384	1,878,383	203,093	2,081,476	1,040,738	2,297,973	Ref Page 2
Depreciation Deferral - UE-132350	(836,250)	(39,539)	(875,789)	(437,894)	(966,881)	Ref Page 2
Hydro Deferral - UE-140094	2,323,739	122,030	2,445,769	1,222,884	2,700,157	Ref Page 2
Merwin Deferral - UE-140617	1,608,118	103,564	1,711,682	855,841	1,889,716	Ref Page 2
Total			**5,363,138**	**2,681,569**	**5,920,965**	

PacifiCorp
Washington General Rate Case - December 2013
Amortization of Deferred Amounts in Base Rates
Revenue Requirement Calculation ($)

	Revenue Requirement			
	Colstrip Deferral Ref Page 3	**Depr. Deferral Ref Page 4**	**Hydro Deferral Ref Page 5**	**Merwin Deferral Ref Page 6**
Addition to Rate Base	1,040,738	(437,894)	1,222,884	855,841
Pre-Tax Return[1]	10.46%	10.46%	10.46%	10.46%
Pre-Tax Return on Rate Base	108,860	(45,803)	127,912	89,520
Amortization Amount	2,081,476	(875,789)	2,445,769	1,711,682
Rev. Reqt. Before Franchise Tax & Bad Debt	2,190,336	(921,592)	2,573,681	1,801,202
WUTC Regulatory Fee[1]	4,596	(1,934)	5,400	3,779
Bad Debt Percentage[1]	14,041	(5,908)	16,498	11,546
Revenue Tax[1]	89,001	(37,447)	104,577	73,189
WA-Allocated Revenue Requirement	**2,297,973**	**(966,881)**	**2,700,157**	**1,889,716**

Note 1 - For details on Rate of Return, WUTC Regulatory Fee, Bad Debt Percentage and Revenue Tax, please refer to Page 10

PacifiCorp
Washington General Rate Case - December 2013
New Deferrals Amortization
UE-131384 - Colstrip Deferral Amortization Schedule

	Adjustment to Amortization Expense		Adjustment to Rate Base (AMA)	
12 ME March 2016	2,081,476	**below**	1,040,738	**below**

Month	Beginning Balance	Additions	Interest Rate[1]	Interest	Amortization	Ending Balance	AMA Balance
Jul-13	-	55,173	7.743%	178	-	55,350	
Aug-13	55,350	261,643	7.743%	1,201	-	318,195	
Sep-13	318,195	287,576	7.743%	2,981	-	608,752	
Oct-13	608,752	290,972	7.743%	4,867	-	904,590	
Nov-13	904,590	285,764	7.743%	6,759	-	1,197,112	
Dec-13	1,197,112	151,189	7.358%	7,803	-	1,356,105	
Jan-14	1,356,105	317,280	7.358%	9,287	-	1,682,672	
Feb-14	1,682,672	228,787	7.358%	11,018	-	1,922,477	
Mar-14	1,922,477	-	7.358%	11,787	-	1,934,264	
Apr-14	1,934,264	-	7.358%	11,859	-	1,946,124	
May-14	1,946,124	-	7.358%	11,932	-	1,958,056	
Jun-14	1,958,056	-	7.358%	12,005	-	1,970,061	
Jul-14	1,970,061	-	7.358%	12,079	-	1,982,140	
Aug-14	1,982,140	-	7.358%	12,153	-	1,994,293	
Sep-14	1,994,293	-	7.358%	12,228	-	2,006,521	
Oct-14	2,006,521	-	7.358%	12,302	-	2,018,823	
Nov-14	2,018,823	-	7.358%	12,378	-	2,031,201	
Dec-14	2,031,201	-	7.358%	12,454	-	2,043,655	
Jan-15	2,043,655	-	7.358%	12,530	-	2,056,185	
Feb-15	2,056,185	-	7.358%	12,607	-	2,068,792	
Mar-15	2,068,792	-	7.358%	12,684	-	2,081,476	
Apr-15	2,081,476	-	-	-	(173,456)	1,908,020	
May-15	1,908,020	-	-	-	(173,456)	1,734,564	
Jun-15	1,734,564	-	-	-	(173,456)	1,561,107	
Jul-15	1,561,107	-	-	-	(173,456)	1,387,651	
Aug-15	1,387,651	-	-	-	(173,456)	1,214,195	
Sep-15	1,214,195	-	-	-	(173,456)	1,040,738	
Oct-15	1,040,738	-	-	-	(173,456)	867,282	
Nov-15	867,282	-	-	-	(173,456)	693,825	
Dec-15	693,825	-	-	-	(173,456)	520,369	
Jan-16	520,369	-	-	-	(173,456)	346,913	
Feb-16	346,913	-	-	-	(173,456)	173,456	
Mar-16	173,456	-	-	-	(173,456)	-	**1,040,738**
		1,878,383		**203,093**	**(2,081,476)**		**Ref Page 2**
	Ref Exhibit No.__(NCS-9) Page 5				**Ref Page 2**		

Note 1 - For details on Interest Rate, please refer to Page 10

PacifiCorp
Washington General Rate Case - December 2013
New Deferrals Amortization
UE-132350 - Depreciation Deferral Amortization Schedule

	Adjustment to Amortization Expense		Adjustment to Rate Base (AMA)	
12 ME March 2016	(875,789)	**below**	(437,894)	**below**

Month	Beginning Balance	Additions	Interest Rate[1]	Interest	Amortization	Ending Balance	AMA Balance
Jan-14	-	(55,750)	7.358%	(171)	-	(55,921)	
Feb-14	(55,921)	(55,750)	7.358%	(514)	-	(112,185)	
Mar-14	(112,185)	(55,750)	7.358%	(859)	-	(168,793)	
Apr-14	(168,793)	(55,750)	7.358%	(1,206)	-	(225,749)	
May-14	(225,749)	(55,750)	7.358%	(1,555)	-	(283,054)	
Jun-14	(283,054)	(55,750)	7.358%	(1,906)	-	(340,711)	
Jul-14	(340,711)	(55,750)	7.358%	(2,260)	-	(398,721)	
Aug-14	(398,721)	(55,750)	7.358%	(2,616)	-	(457,086)	
Sep-14	(457,086)	(55,750)	7.358%	(2,973)	-	(515,810)	
Oct-14	(515,810)	(55,750)	7.358%	(3,333)	-	(574,893)	
Nov-14	(574,893)	(55,750)	7.358%	(3,696)	-	(634,339)	
Dec-14	(634,339)	(55,750)	7.358%	(4,060)	-	(694,149)	
Jan-15	(694,149)	(55,750)	7.358%	(4,427)	-	(754,326)	
Feb-15	(754,326)	(55,750)	7.358%	(4,796)	-	(814,872)	
Mar-15	(814,872)	(55,750)	7.358%	(5,167)	-	(875,789)	
Apr-15	(875,789)	-	-	-	72,982	(802,806)	
May-15	(802,806)	-	-	-	72,982	(729,824)	
Jun-15	(729,824)	-	-	-	72,982	(656,842)	
Jul-15	(656,842)	-	-	-	72,982	(583,859)	
Aug-15	(583,859)	-	-	-	72,982	(510,877)	
Sep-15	(510,877)	-	-	-	72,982	(437,894)	
Oct-15	(437,894)	-	-	-	72,982	(364,912)	
Nov-15	(364,912)	-	-	-	72,982	(291,930)	
Dec-15	(291,930)	-	-	-	72,982	(218,947)	
Jan-16	(218,947)	-	-	-	72,982	(145,965)	
Feb-16	(145,965)	-	-	-	72,982	(72,982)	
Mar-16	(72,982)	-	-	-	72,982	-	**(437,894)**
		(836,250)		**(39,539)**	**875,789**		**Ref Page 2**
	Ref Exhibit No.__(NCS-9) Page 7				**Ref Page 2**		

Note 1 - For details on Interest Rate, please refer to Page 10

PacifiCorp
Washington General Rate Case - December 2013
New Deferrals Amortization
UE-140094 - Hydro Deferral - Replacement Power Cost

	Adjustment to Amortization Expense		Adjustment to Rate Base (AMA)	
12 ME March 2016	(2,445,769)	**below**	1,222,884	**below**

Month	Beginning Balance	Additions[1]	Interest Rate[2]	Interest	Amortization	Ending Balance	AMA Balance
Jan-14	-	712,337	7.358%	2,184	-	714,521	
Feb-14	714,521	286,980	7.358%	5,261	-	1,006,762	
Mar-14	1,006,762	(271,006)	7.358%	5,342	-	741,097	
Apr-14	741,097	(110,673)	7.358%	4,205	-	634,628	
May-14	634,628	(320,310)	7.358%	2,909	-	317,228	
Jun-14	317,228	436,352	7.358%	3,283	-	756,862	
Jul-14	756,862	192,756	7.358%	5,231	-	954,849	
Aug-14	954,849	74,434	7.358%	6,083	-	1,035,366	
Sep-14	1,035,366	724,257	7.358%	8,568	-	1,768,191	
Oct-14	1,768,191	(344,623)	7.358%	9,785	-	1,433,353	
Nov-14	1,433,353	685,725	7.358%	10,890	-	2,129,969	
Dec-14	2,129,969	257,511	7.358%	13,849	-	2,401,328	
Jan-15	2,401,328	-	7.358%	14,723	-	2,416,051	
Feb-15	2,416,051	-	7.358%	14,813	-	2,430,865	
Mar-15	2,430,865	-	7.358%	14,904	-	2,445,769	
Apr-15	2,445,769	-	-	-	(203,814)	2,241,955	
May-15	2,241,955	-	-	-	(203,814)	2,038,141	
Jun-15	2,038,141	-	-	-	(203,814)	1,834,327	
Jul-15	1,834,327	-	-	-	(203,814)	1,630,513	
Aug-15	1,630,513	-	-	-	(203,814)	1,426,699	
Sep-15	1,426,699	-	-	-	(203,814)	1,222,884	
Oct-15	1,222,884	-	-	-	(203,814)	1,019,070	
Nov-15	1,019,070	-	-	-	(203,814)	815,256	
Dec-15	815,256	-	-	-	(203,814)	611,442	
Jan-16	611,442	-	-	-	(203,814)	407,628	
Feb-16	407,628	-	-	-	(203,814)	203,814	
Mar-16	203,814	-	-	-	(203,814)	-	**1,222,884**
		2,323,739		**122,030**	**(2,445,769)**		**Ref Page 2**
Ref UE-140094 - PC 2 - 5th Supp Reponse					**Ref Page 2**		

Note 1 - For details on Additions amounts, please reference UE-140094, Data Request - PC 2, 5th Supplemental Response
Note 2 - For details on Interest Rate, please refer to Page 10

PacifiCorp
Washington General Rate Case - December 2013
New Deferrals Amortization
UE-140617 - Merwin Deferral Amortization Schedule

	Adjustment to Amortization Expense		Adjustment to Rate Base (AMA)	
12 ME March 2016	(1,711,682)	**below**	855,841	**below**

Month	Beginning Balance	Return on Rate Base	O&M Expense	Depreciation Expense	Interest Rate[1]	Interest	Amortization	Ending Balance	AMA Balance
Mar-14	-	1,103,724	-	17,922	7.358%	55		1,121,702	
Apr-14	1,121,702		4,281	35,845	7.358%	6,987	-	1,168,815	
May-14	1,168,815		4,281	35,845	7.358%	7,276	-	1,216,217	
Jun-14	1,216,217		4,281	35,845	7.358%	7,567	-	1,263,910	
Jul-14	1,263,910		4,281	35,845	7.358%	7,859	-	1,311,896	
Aug-14	1,311,896		6,760	35,845	7.358%	8,153	-	1,362,654	
Sep-14	1,362,654		6,760	35,845	7.358%	8,465	-	1,413,724	
Oct-14	1,413,724		4,281	35,845	7.358%	8,778	-	1,462,627	
Nov-14	1,462,627		4,281	35,845	7.358%	9,078	-	1,511,831	
Dec-14	1,511,831		4,281	35,845	7.358%	9,379	-	1,561,337	
Jan-15	1,561,337		4,281	35,845	7.358%	9,683	-	1,611,146	
Feb-15	1,611,146		4,281	35,845	7.358%	9,988	-	1,661,260	
Mar-15	1,661,260		4,281	35,845	7.358%	10,295	-	1,711,682	
Apr-15	1,711,682			-	-	-	(142,640)	1,569,042	
May-15	1,569,042			-	-	-	(142,640)	1,426,401	
Jun-15	1,426,401			-	-	-	(142,640)	1,283,761	
Jul-15	1,283,761			-	-	-	(142,640)	1,141,121	
Aug-15	1,141,121			-	-	-	(142,640)	998,481	
Sep-15	998,481			-	-	-	(142,640)	855,841	
Oct-15	855,841			-	-	-	(142,640)	713,201	
Nov-15	713,201			-	-	-	(142,640)	570,561	
Dec-15	570,561			-	-	-	(142,640)	427,920	
Jan-16	427,920			-	-	-	(142,640)	285,280	
Feb-16	285,280			-	-	-	(142,640)	142,640	
Mar-16	142,640			-	-	-	(142,640)	-	**855,841**
		1,103,724	**56,334**	**448,060**		**103,564**	**(1,711,682)**		**Ref Page 2**
		Ref Page 7	**Ref Page 9**	**Ref Page 8**			**Ref Page 2**		

Note 1 - For details on Interest Rate, please refer to Page 10

PacifiCorp
Washington General Rate Case - December 2013
New Deferrals Amortization
Return on Rate Base Calculation - Merwin Deferral

Return on Rate Base[1]

Capital Investment (in service March 2014)	58,369,301	
Accumulated Depreciation (through March 2015)	(1,033,973)	
Accumulated DIT Balance	(7,745,755)	
Net Rate Base	49,589,574	
Pre-Tax Return from UE-130043	9.88%	Ref Page 10
Pre-Tax Return on Rate Base	4,898,132	
Factor - CAGW from UE-130043	22.5336%	Ref Page 10
WA Revenue Requirement - Return on Rate Base	**1,103,724**	Ref Page 6

Note 1 - Amounts used to calculate Return on Rate Base are taken from Docket No. UE-140617, Attachment F, Page 1 of 6

PacifiCorp
Washington General Rate Case - December 2013
New Deferrals Amortization
Depreciation Expense Calculation - Merwin Deferral

In-Service Date Mar-14
Depreciation Rate 3.270% **CAGW Factor** 22.5336%

		TOTAL COMPANY				WA Allocated
		Plant in Service	Accumulated Depreciation [1]	Depreciation Expense[1]	ADIT	Depreciation Expense
CY 2014	Jan-14	-	-	-		-
	Feb-14	-	-	-		-
	Mar-14	58,369,301	(79,536)	79,536		17,922
	Apr-14	58,369,301	(238,609)	159,073		35,845
	May-14	58,369,301	(397,682)	159,073		35,845
	Jun-14	58,369,301	(556,754)	159,073		35,845
	Jul-14	58,369,301	(715,827)	159,073		35,845
	Aug-14	58,369,301	(874,900)	159,073		35,845
	Sep-14	58,369,301	(1,033,973)	159,073		35,845
	Oct-14	58,369,301	(1,193,045)	159,073		35,845
	Nov-14	58,369,301	(1,352,118)	159,073		35,845
	Dec-14	58,369,301	(1,511,191)	159,073		35,845
	2014 Ending Bal.	**58,369,301**	**(1,511,191)**	**1,511,191**		**340,525**
						-
CY 2015	Jan-15	58,369,301	(1,670,263)	159,073		35,845
	Feb-15	58,369,301	(1,829,336)	159,073		35,845
	Mar-15	58,369,301	(1,988,409)	159,073		35,845
	Apr-15	58,369,301	(2,147,482)	159,073		35,845
	May-15	58,369,301	(2,306,554)	159,073		35,845
	Jun-15	58,369,301	(2,465,627)	159,073		35,845
	Jul-15	58,369,301	(2,624,700)	159,073		35,845
	Aug-15	58,369,301	(2,783,772)	159,073		35,845
	Sep-15	58,369,301	(2,942,845)	159,073		35,845
	Oct-15	58,369,301	(3,101,918)	159,073		35,845
	Nov-15	58,369,301	(3,260,990)	159,073		35,845
	Dec-15	58,369,301	(3,420,063)	159,073		35,845
	2015 Ending Bal.	**58,369,301**	**(3,420,063)**	**1,908,872**		**430,137**
	AMA (Mar 2014 to Mar 2015)	**58,369,301**	**(1,033,973)**	**1,908,872**	**(7,745,755)**	**448,060**
						Ref Page 6

Note 1 - Accumulatd Depreciation and Depreciation Expense amounts are taken from Docket No. UE-140617, Attachment F, Page 3 of 6

PacifiCorp
Washington General Rate Case - December 2013
New Deferrals Amortization
Operations & Maintenance Expense Calculation - Merwin Deferral

	TOTAL COMPANY												
O&M Costs[1]	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Total 12 Months**
Merwin Fish Collector	$ 19,000	$ 19,000	$ 19,000	$ 19,000	$ 30,000	$ 30,000	$ 19,000	$ 19,000	$ 19,000	$ 19,000	$ 19,000	$ 19,000	**$ 250,000**

	WASHINGTON ALLOCATED												
O&M Costs	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Total 12 Months**
Merwin Fish Collector	$ 4,281	$ 4,281	$ 4,281	$ 4,281	$ 6,760	$ 6,760	$ 4,281	$ 4,281	$ 4,281	$ 4,281	$ 4,281	$ 4,281	**$ 56,334**
													Ref Page 6
CAGW FACTOR	22.5336%												

Note 1 - O&M Expense amounts are taken from Docket No. UE-140617, Attachment F, Page 5 of 6

PacifiCorp
Washington General Rate Case - December 2013
Deferrals for Colstrip Outage, Hydro, and Depreciation
Effective cost of capital and factors during deferral and amortization periods
Taken from Exhibit No.__(NCS-9), Page 8

Capital Cost and Structure Requested in UE-140762

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	48.25%	5.18%	2.499%		2.50%
Preferred	0.02%	6.75%	0.001%	153.85%	0.00%
Common	51.73%	10.00%	5.173%	153.85%	7.96%
Total	100.00%		7.67%		10.46%
Merged Effective Tax Rate					35.000%
Pre-Tax Bump-up Factor					153.85%
Revenue Sensitive Items - UE140762					
WUTC Regulatory Fee			0.200%	0.210%	
Bad Debt Percentage			0.611%	0.641%	
Revenue Tax			3.873%	4.063%	
WCA Allocation Factors - UE 140762					
Washington CAGW Factor			23.0849%		
Washington CAEW Factor			22.7414%		

Capital Cost and Structure Ordered from UE-130043

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	50.62%	5.29%	2.678%		2.68%
Preferred	0.28%	5.43%	0.015%	153.85%	0.02%
Common	49.10%	9.50%	4.665%	153.85%	7.18%
Total	100.00%		7.36%		9.88%
Merged Effective Tax Rate					35.000%
Pre-Tax Bump-up Factor					153.85%
Revenue Sensitive Items - UE 130043					
WUTC Regulatory Fee			0.200%	0.210%	
Bad Debt Percentage			0.660%	0.693%	
Revenue Tax			3.848%	4.038%	
WCA Allocation Factors - UE 130043					
Washington CAGW Factor			22.5336%		
Washington CAEW Factor			22.6481%		

Capital Cost and Structure Ordered from UE-111190

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	50.60%	5.76%	2.915%		2.91%
Preferred	0.30%	5.43%	0.016%	153.85%	0.03%
Common	49.10%	9.80%	4.812%	153.85%	7.40%
Total	100.00%		7.74%		10.34%
Merged Effective Tax Rate					35.000%
Pre-Tax Bump-up Factor					153.85%
Revenue Sensitive Items - UE 111190					
WUTC Regulatory Fee			0.200%	0.210%	
Bad Debt Percentage			0.507%	0.531%	
Revenue Tax			3.873%	4.059%	
WCA Allocation Factors - UE 111190					
Washington CAGW Factor			22.4742%		
Washington CAEW Factor			22.3245%		

Exhibit No. NCS-16
Docket UE-140762 *et al.*
Witness: Natasha C. Siores

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF NATASHA C. SIORES

Miscellaneous Support for Rebuttal Testimony of Natasha C. Siores

November 2014

PacifiCorp
Washington General Rate Case – December 2013
Copy of 2015 Public Utility Tax Credit Approval Letter

DEPARTMENT OF REVENUE
WASHINGTON STATE

July 30, 2014

DAVID HIPPS
PACIFICORP
ATTN: TAX DEPT
825 NE MULTNOMAH ST STE 1900
PORTLAND, OR 97232-2151

2015 Fiscal Year Low Income Home Energy Assistance Program (LIHEAP) Credit Certificate Enclosed
Tax Registration Number: [redacted]

Dear DAVID HIPPS,

Your Public Utility Tax Credit Application for LIHEAP has been approved

- Your approved credit amount is **$165,997.53.**
- You may take this credit on your July 2014 thru June 2015 returns.
- Any unused credit expires on June 30, 2015 and cannot be carried forward.

The credit amount does not match the amount you calculated on Line 11 of your application

- Your approved credit is a result of recalculation process based on all businesses that qualified and applied for the LIHEAP credit

How to use this credit

- This credit is reported on page 2 of your tax return, in the following credit section:
  - Public Utility Tax Credit for Billing Discounts/Qualified Contributions to a Low Income Home Energy Assistance Fund.
- Please make a copy of the certificate and attach a copy with each return that you are taking the credit.
  - Fill in the amount you are taking on the current return in the space provided.
- The credit cannot exceed 50% of the combined total of your actual billing discounts and qualifying contributions during the same period for which it is reported.

If you have any questions regarding this credit, please contact me at (360) 902-7025.

Sincerely,

Sheri Rufener
Excise Tax Examiner
Taxpayer Account Administration

Enclosure

UE-140762/Pacific Power & Light Company
July 21, 2014
PC Data Request 53

PC Data Request 53

Re: Plant Additions. For each of the capital projects listed on Exhibit No.__(NCS-3), p. 8.4.2, please provide supporting documentation for the capital addition. Supporting documentation should include, where applicable, expenditure requisitions, appropriation requests, investment appraisal documents, project work orders, project change notices, cost benefit analysis or any other relevant studies or analysis in support of the project.

Response to PC Data Request 53

Please refer to Attachment PC 53-1, Confidential Attachment PC 53-2, Confidential Attachment PC 53-3, Attachment PC 53-4, and Attachment PC 53-5.

Attachment PC 53-1 lists the capital projects from page 8.4.2 of Exhibit No. NCS-3 and identifies the attachments containing the supporting documentation for each project.

Confidential information is provided subject to the terms and conditions of the protective order in this proceeding.

Confidential Attachment PC 53-2, Confidential Attachment PC 53-3, Attachment PC 53-4, and Attachment PC 53-5 are provided in electronic format only.

PREPARER: Nathan Adent/Karl Mortensen/Dave Webb/Lisa Harkins

SPONSOR: Natasha C. Siores

WA UE-140762
PC 53

Attachment PC 53-1

PacifiCorp
Washington General Rate Case - December 2013
Pro Forma Major Plant Additions

Project Description	Attachment containing supporting documentation
Transmission	
Alvey Series Cap Controls - Payment to BPA	Attach PC 53-4
Fry Sub Instl 115 kV Capacitor Bank TPL2	Attach PC 53-2 CONF
Knott Sub Install 115-12.5 kV Transformer - Transmission Portion	Attach PC 53-4
Line 3 Convert to 115kV - Phase 1and 2	Attach PC 53-4
Middleton-Toquerville: 69 kV Line Rebuild 2.2 Miles	Attach PC 53-4
Purchase spare 230-69 kV 150 MVA Transformer (Klamath)	Attach PC 53-4
U2 GSU Transformer Upgrade Replacement	Attach PC 53-3 CONF
Steam Production	
JB New Sewage Treatment Plant or Lagoon	Attach PC 53-3 CONF
JB U1 Burners - Major 14	Attach PC 53-3 CONF
JB U1 Pendant Plat Lower Replacement 14	Attach PC 53-3 CONF
JB U1 Replace Cooling Tower 13/14	Attach PC 53-3 CONF
Colstrip 4: Generator Repair CY13 & CY14	Attach PC 53-3 CONF
Hydro Production	
ILR 4.3 Merwin Upstream Collect & Trans	Attach PC 53-3 CONF
ILR 6.2 Merwin Flow Controls	Attach PC 53-3 CONF
ILR 8.7 Speelyai Hatchery Water Intake	Attach PC 53-3 CONF
INU 10.6 Aquatic Connectivity 14	Attach PC 53-3 CONF
Merwin 1 TIV Overhaul	Attach PC 53-3 CONF
Merwin 3 TIV Overhaul	Attach PC 53-3 CONF
Soda Springs Screen Upgrade	
Swift 1 Spare Generator Windings	Attach PC 53-3 CONF
Swift 11 Generator Rewind	Attach PC 53-3 CONF
Swift Main Net Modifications	Attach PC 53-3 CONF
Swift Side Nets Replacement	Attach PC 53-3 CONF
Yale Upper Rock Block Stabilization	Attach PC 53-3 CONF
General Plant	
Call Center ACD Replacement Project	Attach PC 53-5
Replace 6GHz MW radios Starvout to Fort Rock phase 2	Attach PC 53-4
Distribution Plant	
Orchard and Wiiley Substation Capacity Relief (Clinton Feeder)	Attach PC 53-4
Replace Spare 116-13.0kV 25 MVA w/ LTC - Yakima	Attach PC 53-4
Selah Substation Capacity Relief (25 MVA at Pomona Heights)	Attach PC 53-4
Union Gap - Add 230 - 115kV Capacity - TPL002	Attach PC 53-2 CONF

Files provided in Confidential Attachment PC 53-2, Confidential Attachment PC 53-3, Attachment PC 53-4, and Attachment PC 53-5

Confidential Attachment PC 53-2 (19 files, 2 folders)

<u>Fry_Confidential</u>
13_0530 Fry Sub One Line.pdf
13_0531 FryGeneralPlanConceptSketch.pdf
13_0531 FryOneLineCapacitorAddition.pdf
13_0531 FrySubstationScopeofWork.doc
13_0606 FrySub IAD.docx
13_0705 Fry Sub Instl 115kV Cap Bank_APR 24005218.pdf
14_0418 Fry Instl 115kV Cap Bank_PCN 94004562.pdf

<u>Union Gap_Confidential</u>
10_0908 UnionGapSub_Original ER.xls
11_0214 Union Gap_APR 94000509.pdf
11_0227 Union Gap_APR 24001111.pdf
11_0411 Union Gap_APR 94000700.pdf
11_1004 Union Gap_ER.xls
11_1006 Union GAP_APR 94001273 IAD Waiver.pdf
11_1012 Union Gap_APR 94001273.pdf
12_1004 Union Gap IAD.docx
12_1024 Union Gap ONELINE01-Layout1.pdf
12_1108 Union Gap GM.xlsm
13_0121 Union Gap APR94002629 Delegation of Authority.pdf
13_0122 Union Gap_APR 94002629.pdf

Confidential Attachment PC 53-3 (20 files)

APR10003217-JB U1 Replace Cooling Tower.doc
APR10003280-JB U1 Burners - Major 14.doc
APR10003282-JB U1 Pendant Plat Lower Repl 14.doc
APR10008718-Merwin 3 TIV Overhaul CONF.doc
APR10009306-JB New Sewage Trmt Plant or Lagoon.doc
APR10013945-Aquatic Connectivity 14 CONF.doc
APR10014332-Swift 1 Spare Generator Windings CONF.doc
APR10015572-Swift 11 Generator Rewind CONF.doc
APR10015901-JB U2 GSU Trnsfrmr Upgrade Repl.doc
APR10017690-Merwin 1 TIV Overhaul CONF.doc
APR10017856-Yale Upper Rock Block Stabilization CONF.doc
APR10018529-Swift Main Net Modifications CONF.doc
APR20002820-Soda Springs Screen Upgrade CONF.doc
APR20003310-Swift Side Nets Replacement CONF.doc
APR20003336-Merwin Upstream Collect & Transport CONF.doc
APR90000460-Speelyai Hatchery Water Intake CONF.doc
APR90000720-Merwin Flow Controls CONF.doc
APR90000785-Yale Upper Rock Block Stab-Proj Chg CONF.doc
Colstrip U4 Generator Repair CONF.pdf
Colstrip U4 Generator Rotor Rewind.pdf

Files provided in Confidential Attachment PC 53-2, Confidential Attachment PC 53-3, Attachment PC 53-4, and Attachment PC 53-5

Attachment PC 53-4 (36 files)

Alvey Series Cap APR.pdf
Alvey Series Cap IAD.pdf
K Falls Spare 230-6pkV Transformer APR 2013-0709.pdf
k Falls Spare 230-69kV Transformer PCN 2014-0522.pdf
KFALLS 230-69kV 150MVA SPARE TRF IAD 2014-0502.pdf
KFALLS spare 230-69kV 150 MVA transformer IAD 2013-0611.pdf
Knott Sub Cap Incr APR 2011-0429.pdf
Knott Sub Cap Incr PCN 2012-0327.pdf
Knott Sub Cap Incr PCN 2013-0709.pdf
Knott Sub Cap Incr PCN 2014-0226.pdf
Knott_Sub_Incr_Cap IAD_2011-0308.pdf
Line 3 Convert to 115 kV ER R1 2009-0324.pdf
Line 3 Convert to 115kV ER 2010-0520.pdf
Line 3 Convert to 115kV Executive IAD 2010-0113.pdf
Line 3 Convert to 115kV Executive IAD 2012-0730.pdf
Line 3 Convert to 115kV PCN 2010-0520.pdf
Line 3 Convert to 115kV PCN 2012-0508.pdf
Line 3 Convert to 115kV PCN 2012-0830.pdf
Line 3 Convert to 115kV PCN 2014-0626.pdf
Middleton Revised IAD 2012-0306.pdf
Middleton-Toquerville Cash Shift 2010-0125.pdf
Middleton-Toquerville Engineering ER 2008-0310.pdf
Middleton-Toquerville rebuild 138kV PCN 2010-1005.pdf
Middleton-Toquerville rebuild 138kV PCN 2012-0402.pdf
Middleton-Toquerville rebuild 138kV PCN 2013-0212.pdf
Middleton-Toquerville rebuild 138kV-Executive IAD 2010-0930.docx
Orchard and Wiley - Clinton Sub Fdr IAD_2013-0425.pdf
Orchard-Wiley - Clinton Sub Fdr - APR.pdf
Selah Sub Relief - Pomona Heights Incr Cap APR 2013-0607.pdf
Selah Sub Relief - Pomona Heights Incr Cap PCN 2014-0324.pdf
Selah Sub Relief - Pomona Heights-Add 115-12kV Capacity IAD_2013-0520.pdf
Spare Xfmr Yakima - APR 2013-0718.pdf
Starvout - Fort Rock MW Replacement APR 2011-0831.pdf
Starvout - Fort Rock MW Replacement PCN 2013-0115.pdf
Starvout - Fort Rock MW Replacement PCN 2013-1107.pdf
Starvout_Fort Rock IAD 2011-0508.pdf

Attachment PC 53-5 (3 files)

Attach PC 53-5.1.pdf
Attach PC 53-5.2.pdf
Attach PC 53-5.3.pdf

Exhibit No. JRS-13T
Docket UE-140762 *et al.*
Witness: Joelle R. Steward

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF JOELLE R. STEWARD

November 2014

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ATTACHED EXHIBITS

Q. Are you the same Joelle R. Steward who previously submitted direct testimony in this case on behalf of Pacific Power & Light Company (Pacific Power or Company) in this case?

A. Yes.

PURPOSE AND SUMMARY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to present the class cost of service (COS) study results, rate spread, and rate design proposals reflecting the Company's revised revenue requirement. I also respond to the direct testimony of Mr. Jeremy B. Twitchell on behalf of the Washington Utilities and Transportation Commission (Commission) Staff, Mr. Glenn A. Watkins on behalf of the Public Counsel Division of the Washington Attorney General's Office (Public Counsel), Mr. Charles Eberdt on behalf of the Energy Project, Mr. Robert R. Stephens on behalf of Boise White Paper, LLC (Boise), Mr. Steve W. Chriss on behalf of Wal-Mart Stores, Inc. and Mr. Mark E. Fulmer on behalf of The Alliance for Solar Choice (TASC), regarding their positions on COS, rate spread, and rate design.

Q. Please summarize your testimony.

A. The findings and recommendations in my rebuttal testimony are:

- The Company's COS study is consistent with prior Commission direction and presents a reasonable balance between the interests of all parties. Staff's recommendation to create a separate allocation factor for non-dispatchable generation (i.e., wind resources) in the COS study inappropriately singles out one type of resource and relies on a capacity value for wind that is inconsistent with the west control area. The Company is not opposed to Staff's recommendation for a direct assignment of customer account managers but I recommend that if it is adopted that the costs be allocated based on the number of customers.

- The Company continues to recommend a rate spread that reasonably balances the interests of all parties as well as the COS results. The Company's proposed rate spread allocates one half of the overall increase to Schedules 24, 40, and lighting, with the remaining increase spread equally to the rest of the rate schedules.

- For residential rate design, the Company continues to recommend a basic charge of $14.00 per month for Schedule 16 and $8.75 per month for Schedule 17. The Company also recommends that the Commission retain the current two block energy rate structure.

- The proposed $14.00 residential basic charge will allow the Company a better opportunity to recover its fixed costs. The proposed basic charge would recover a portion of the costs related to retail services and distribution investments, which are necessary for the safe and reliable service to all residential customers regardless of usage levels. The proposed basic charge is in line with the average basic charge for customers in Washington.

- Even with the increase in the residential basic charge, the current residential rate structure will continue to be heavily weighted on energy use, thus providing a strong signal for conservation. Nearly 90 percent of an average customer's bill is based on their overall usage and only 11 percent due to the basic charge.

- Change to the current residential two-block rate structure proposed by Staff should be denied because it: (1) sends a confusing price signal to customers by reducing 45 percent of customer bills, which may encourage increased usage for these customers; (2) is not cost based and appears to be largely designed to be punitive for electric heat customers; (3) will disproportionately impact low income customers; (4) will increase the risk of cost recovery for the Company; and (5) may have unintended consequences of sending an uneconomic price signal to customers for distributed generation, which would have adverse impacts for both the Company and other customers.

- The current residential rate structure already reflects a steeply inverted block rate, particularly when compared to Avista and Puget Sound Energy, and the first block set at 600 kWh already reasonably reflects the average usage in Washington for lighting, appliances, and water heating.

- Staff's discussion and recommendation that the Commission prejudge potential rate solutions for distributed generation customers is misguided and inappropriate and should be dismissed.

- For non-residential rate design, the Company proposes a higher increase in the demand charge for Schedule 36, in response to Wal-Mart's proposal; however, in order to moderate intra-class impacts, the Company is proposing a smaller increase in the demand charge than that proposed by Wal-Mart. The proposed rates for all other non-residential rate schedules are consistent with my direct testimony.

COST OF SERVICE

Q. Please summarize the methodology used for the Company's COS study in the initial filing.

A. In the initial filing the Company's COS study was based on the same methodologies used in the Company's 2013 general rate case, Docket UE-130043 (2013 Rate Case). Specifically, for generation and transmission costs the Company classifies costs between demand and energy using the west control area system diversified load factor (SDLF), which results in 43 percent of these costs classified as demand related and 57 percent classified as energy related. The demand-related costs are then allocated to rate schedules using the Company's highest 100 summer (April-October) and 100 winter (November-March) hourly retail peak loads in the west control area. The energy-related portion is allocated to rate schedules using class annual load (megawatt hours), adjusted for losses. This allocation approach is consistent with prior Commission direction. For distribution and retail service costs, the Company also uses methodologies consistent with prior cases. No party raised concerns with how distribution and retail service costs were treated in the COS study. Accordingly, cost allocations I discuss for this rebuttal testimony refer to only generation and transmission costs.

Q. Is the Company proposing changes to the COS in this rebuttal filing?

A. No. The only change reflected in the COS study is to incorporate the rebuttal results of operation for Washington presented in the rebuttal testimony of Ms. Natasha C. Siores. After reviewing the COS changes proposed by Staff, Public Counsel, and

Boise, the Company is not proposing methodological changes in the COS study for this proceeding. The Company's COS study fairly balances the study results given the range of approaches proposed by the parties. Furthermore, the Company's proposed rate spread, which is guided by the COS study, fairly balances the impacts for all customer classes. Exhibit No. JRS-14 contains summary tables from the Company's COS study for the state of Washington based on the revised revenue requirement proposed in this rebuttal filing. Exhibit No. JRS-15 displays the COS study in more detail by class and function: page 1 summarizes the total COS by class, pages 2 through 6 contain a summary by class for each major function, and pages 7 through 9 contain the unit costs by function and class.

Q. How do the results from the Company's COS study compare with the COS approaches advocated by the other parties?

A. Table 1 compares the Company's COS results and parity ratios (Scenario 3) with Public Counsel's (Scenario 1), Staff's (Scenario 2), and Boise's proposals (Scenario 5) based on the Company rebuttal revenue requirement. Scenario 4 (Hybrid) is a hybrid method that shows the impact on COS results if classification is treated consistently with the West Control Area inter-jurisdictional allocation methodology (WCA). Consistency between the class COS and the jurisdictional cost allocations is another approach that would be reasonable in order to align the costs allocated to customers with the drivers that allocate costs to Washington.

Table 1

	Scenario 1 Public Counsel	Scenario 2 Staff	Scenario 3 Company	Scenario 4 Hybrid	Scenario 5 Boise
Description	Total Cost of Service	Total Cost of Service	Total Cost of Service	Total Cost of Service	Total Cost of Service
Residential	$ 160,637,995	$ 163,125,621	$ 163,792,081	$ 166,346,668	$ 175,526,406
Sch. 24	$ 47,870,801	$ 47,730,862	$ 47,734,808	$ 47,624,664	$ 45,448,270
Sch. 36	$ 71,082,239	$ 70,370,854	$ 70,232,276	$ 69,543,851	$ 66,915,069
Sch 48T	$ 28,792,411	$ 28,232,286	$ 28,011,710	$ 27,379,399	$ 25,524,208
Sch 48T-Ded.	$ 29,621,414	$ 28,759,545	$ 28,476,719	$ 27,549,612	$ 25,315,396
Irrigation	$ 12,895,583	$ 12,749,926	$ 12,730,015	$ 12,595,914	$ 12,435,585
Street Lighting	$ 1,700,526	$ 1,631,875	$ 1,623,358	$ 1,560,861	$ 1,436,036
WA Jurisdiction	$ 352,600,969	$ 352,600,969	$ 352,600,969	$ 352,600,969	$ 352,600,969
Description	Parity Ratios	Parity Ratios	Parity Ratios	Parity Ratios	Parity Ratios
Residential	0.87	0.86	0.86	0.84	0.80
Sch. 24	1.01	1.02	1.02	1.02	1.07
Sch. 36	0.94	0.95	0.95	0.96	1.00
Sch 48T	0.90	0.92	0.93	0.95	1.02
Sch 48T-Ded.	0.84	0.87	0.88	0.91	0.99
Irrigation	0.98	0.99	0.99	1.01	1.02
Street Lighting	0.97	1.01	1.02	1.06	1.15
WA Jurisdiction	0.91	0.91	0.91	0.91	0.91

Scenario 1: 100S/100W, 30%D/70%E (Public Counsel)
Scenario 2: NDG and CAM Direct Assignment (Staff)
Scenario 3: 100S/100W, 43%D/57%E (Company)
Scenario 4: 100S/100W, 100%E for Variable Costs, 75%D/25%E for Fixed Costs (Hybrid)
Scenario 5: 4CP-Production, 12CP-Transmission, 100%E-Variable and 100%D-Fixed Costs, (Boise)

Please see workpapers "Scenario 1-5".

Q. What general conclusions can you draw from the comparison of the various COS proposals in this case?

A. As shown in Table 1, the Company's proposal (Scenario 3) falls in the middle, between the proposals of Staff and Public Counsel on the one hand, and Boise on the other. The Company's proposal appropriately balances the interests of all customer classes and its central position as compared to Staff and intervenors further demonstrates the overall reasonableness of the Company's position.

Q. What changes does Public Counsel propose for the COS study?

A. For the most part, Public Counsel agrees with the Company's current SDLF or load factor methodology for classifying costs between demand and energy but with caveats on the reasonableness and stability of the method.[1] Public Counsel makes several proposals that may be substituted including a forward-looking load factor such as the one provided in the Integrated Resource Plan (IRP), an average of multiple hours' highest peak loads within a single year, or multiple years annual peak loads.

Q. Public Counsel raises a concern about a potential anomaly between the 2013 peak load data that the Company used in its SDLF calculation and the 2014 and 2015 forecast peak load data in the 2013 IRP. Specifically, Public Counsel argues that if the forecast load factor from the IRP were used then 28 percent of costs would be classified as demand related rather than 43 percent.[2] Is this an anomaly as Public Counsel suggests?

A. No. The forecast coincident peak in the IRP looks at the loads of the west control area at the time of the Company's entire system peak, which includes the west control area loads and all other states within the Company's system (Utah, Wyoming, and Idaho). The difference in the IRP coincident peaks and the peak utilized by the Company can simply be attributed to the different peak times of the west control area and the entire PacifiCorp system. The west control area coincident peak would be 3,361 megawatt (MW) at the time of the PacifiCorp system peak, a value significantly closer to those in the IRP forecasts.

[1] Testimony of Glenn A. Watkins, Exhibit No. GAW-1T at 10:18-21.
[2] *Id*. at 12:1-11.

Q. Public Counsel proposes classifying generation and transmission costs as 30 percent demand related and 70 percent energy related as a closer approximation of the IRP load factor. What effect does this have on COS results when compared with the Company's filed COS study?

A. Scenario 1 in Table 1 above illustrates the impact on COS results of classifying these costs as 30 percent demand related and 70 percent energy related. As would be expected, when classifying more costs as energy related, costs are shifted from lower load factor customers (residential) to higher load factor customers (industrial or large general service).

Q. Is using a 30/70 percent split between demand and energy an appropriate methodology for class COS in Washington?

A. No. The Company does not use system peaks to allocate costs in Washington; therefore, this approach is unreasonable and is inconsistent with the WCA.

Q. What recommendations does Staff propose for the COS study?

A. Staff proposes classifying non-dispatchable generation (NDG) costs primarily as energy related and directly assigning the costs of corporate account managers (CAM) to large industrial customers.

Q. Please describe Staff's proposed NDG allocation factor.

A. Staff proposes a new allocation factor to classify and allocate costs specifically related to solar and wind resources. Staff recommends that a larger portion of the costs of these resources be classified as energy related with the demand-related portion to be determined by a capacity credit developed for the Company's IRP. In support of this position Staff argues that since compliance with the Renewable

Portfolio Standard (RPS) is energy based it is more consistent to assign costs based on customer energy usage. Additionally, while Staff recognizes that the impact on COS results is small right now, Staff claims that the impact is expected to increase with the growth of wind in the Company's portfolio.[3]

Q. Do you agree with Staff's proposed NDG allocation factor?

A. No. I disagree with the NDG proposal for a numbers of reasons. First, as explained in my direct testimony, the fleet of generation resources is comprised of multiple generation types and the Company's proposed classification recognizes the combined nature of these resources, which together are designed to meet peak load and supply the energy needs of its customers. Singling out one type of resource while continuing to use a factor developed for the entire fleet for all other resources will bias the results.[4] To be consistent, treating NDG differently would require the classification of all generation and transmission resources to be reassessed in both the WCA and the class cost of service methodology. This point is further supported by Public Counsel.[5]

Second, Staff's use of a wind capacity value of 18.1 is not consistent with the WCA. When a wind capacity value relevant to the west control area is used, the impact of the change in the COS results is de minimis.

Third, while wind may make up a larger percentage of the Company's resources in the future, the Company's 2013 IRP Preferred Portfolio does not have

[3] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 18.

[4] In direct testimony Staff rejects the Company's proposed Renewable Resource Tracking Mechanism (RRTM) because it is designed to address a single factor of the utility's net power costs. *Id*. at 14:1-4. Ironically, Staff's proposed NDG allocation factor singles out for special treatment the same specific resource type in the Company's COS study.

[5] Testimony of Glenn A. Watkins, Exhibit No. GAW-1T at 14:19 – 15:7.

any new wind resources being installed until 2024.[6] Because the adoption of Staff's proposed NDG factor results in only minimal changes in the COS results and would not alter the Company's proposed rate spread and rate design, there is no need to reflect this change at this time in light of the principled concerns of this approach.

Q. If all resource types were to be looked at separately for their contribution to peak, similar to how Staff proposes to treat wind resources, would that alter the classification of demand?

A. Yes. Table 2 lists the generation resources included in the west control area. Included in the table for each generation resource is the 2013 energy, installed nameplate capacity rating, capacity factor, peak hour output, and calculated coincident peak hour load factor. The coincident peak load factor is a similar calculation to the SDLF used for classifying generation costs. The west control area peak hour occurred on December 9, 2013 at 8:00 am. This table shows on a total west control area basis that the classification of demand and energy could logically be split equally at 50 percent. Looking at wind individually, it has a coincident peak load factor of 37.5 percent in the west control area, which would be a better proxy for its capacity value.

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[6] PacifiCorp's 2013 Integrated Resource Plan, Docket UE-120416, 2013 Integrated Resource Plan, Volume 1 at Table ES.3, at page 11 (April 30, 2013).

Table 2

Generation Sources	Net Generation Excluding Plant Use	Installed Capacity Name Plate Rating (MW)	Capacity Factor	Peak Hour (MW)	Coincident Peak Load Factor
Natural Gas	2,968,103	873	38.8%	176	20.2%
Coal	10,773,681	1,706	72.1%	1,105	64.8%
Wind	919,274	405	25.9%	152	37.5%
Hydro	2,907,587	917	36.2%	506	55.2%
Total	17,568,645	3,901	51.4%	1,939	49.7%

Q. What is the source of Staff's proposed 18.1 percent wind capacity value?

A. The 18.1 percent wind capacity value is from the Company's 2014 Wind and Solar Capacity Contribution Study. The study is being utilized in the Company's 2015 IRP.

Q. Should the 18.1 percent capacity value of the Company's system wind resources be used for the Company's west control area wind resources?

A. No. First, the 18.1 percent capacity value for wind is for PacifiCorp's entire system which includes 2,117 MW of wind capacity made up of east and west owned wind and east and west non-owned wind. The west control area owned wind resources include Marengo I and II (210 MW), Goodnoe Hills (94 MW) and Leaning Juniper 1 (101 MW) for a total of 405 MW, which is included in the west-owned wind category. The referenced IRP study calculated separate east and west balancing authority area (BAA) wind contribution values, which are shown in Table 3. The 18.1 percent peak capacity contribution factor is a weighted average of the two balancing areas. The West BAA has a wind peak contribution factor of 25.4 percent. Therefore, if this study were to be used to assign a capacity value to wind, 25.4

percent would be a more accurate capacity value as it is calculated for the West BAA, which includes the west control area wind farms.

Table 3

	East BAA Wind	West BAA Wind
CF Method Results	14.5%	25.4%

Second, the methodologies of the Peak Capacity Contribution Value for Wind and the SDLF are not consistent. From page 1 of the 2014 Wind and Solar Capacity Contribution Study:

> The study evaluates the relationship between reliability across all hours in a given year, accounting for variability and uncertainty in load and generation resources, and the cost of planning for system resources at varying levels of planning reserve margin. In this way, PacifiCorp's planning reserve margin LOLP study is the mechanism used to transform hourly reliability metrics into a resource adequacy target ***<u>at the time of system coincident peak</u>*** [emphasis added]. This same LOLP study was utilized for calculating the peak capacity contribution using the CF Method.

The west control area peak hour from which the SDLF is derived is not the same as the system coincident peak evaluated in the study and thus the study should not be utilized to determine west control area wind resources' contribution to west control area coincident peaks. To be consistent with the west control area, one would use the capacity value of the west control area wind resources during the west control area system peak hour of December 9, 2013 at 8:00 am. As shown in Table 2 above, during this peak hour, the west control area wind farms' output was 152 MW, or 37.5 percent of the installed 405 MW of capacity. As previously noted, this would have a de minimis impact on the COS results.

Q. As part of the reasoning for the proposed NDG allocation factor, Staff explains that west control area states have adopted energy-based RPS. Is there a reason for this?

A. Washington's RPS is logically tied to energy sales as it is simple, easy to understand and administer. Any RPS program based on demand or a classification split between demand and energy would seem overly complicated. Therefore, this RPS-based argument should have no bearing.

Q. Please explain Staff's recommendation regarding the allocation of costs for corporate account managers (CAMs).

A. Staff proposes that expenses related to CAMs be directly assigned to Schedule 48T since CAMs are assigned to only large customers (loads over 750 kW).

Q. Is the Company opposed to the direct assignment of these costs?

A. No. However, the impact of the proposed change is minimal at only about $185,000.[7] Furthermore, as explained in my direct testimony, singling out one customer service cost for one type of customer and isolating individual cost drivers to specific types of customers would be complex and burdensome.

Q. If the CAM direct assignment is adopted by the Commission, how do you propose these costs to be allocated?

A. If adopted by the Commission, I propose that the CAM costs be allocated to Schedule 48T and the Dedicated Facilities rate schedules based on the number of customers on those rate schedules. Table 4 illustrates the impact of this change from the initial filed cost of service study.

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[7] It is worth noting that elsewhere Staff described an amount of $254,000 as almost infinitesimal. *See* Testimony of Roger Kouchi, Exhibit No. RK-1T at 7:18-20.

Table 4

Description	Total Cost of Service	Staff Cost of Service	Change in Cost of Service
Residential	$ 163,792,081	$ 163,645,520	-0.09%
Sch. 24	$ 47,734,808	$ 47,708,483	-0.06%
Sch. 36	$ 70,232,276	$ 70,230,772	0.00%
Sch 48T	$ 28,011,710	$ 28,194,648	0.65%
Sch 48T-Ded.	$ 28,476,719	$ 28,479,718	0.01%
Irrigation	$ 12,730,015	$ 12,722,659	-0.06%
Street Lighting	$ 1,623,358	$ 1,619,170	-0.26%
WA Jurisdiction	$ 352,600,969	$ 352,600,969	0.00%

Q. What methodology does Boise propose regarding the classification and allocation of generation and transmission costs?

A. Boise proposes classifying 100 percent of fixed generation costs as demand related and 100 percent of variable costs as energy related because, Boise argues, production investment is primarily driven by the need for capacity and customer peak demands. The variable costs primarily include fuel-related net power costs and purchased power with all other costs considered fixed.[8] Table 5 illustrates the proportional split between fixed and variable generation and transmission costs with Boise's proposal.

Table 5

Fixed vs Variable Generation & Transmission Costs			
	Fixed (Demand)	Variable (Energy)	Total
Boise Proposal	$ 209,645,409	$ 74,698,903	$284,344,312
Share	74%	26%	

For allocation of demand-related costs, Boise argues that the Company provides no basis for allocating these costs with the top 100 winter and 100 summer

[8] The FERC accounts considered to be variable by Boise were 501, 501NPC, 503, 518, 547NPC, and 555 (in part). Responsive Testimony of Robert R. Stephens, Exhibit No. RRS-1T at 20, footnote 14.

peak hours and proposes using only the top four coincident peaks, consisting of the two highest summer months (July and August) and the two highest winter months (December and January).

For transmission costs, Boise proposes to classify all transmission as 100 percent demand related with allocations to rate schedules based on the 12 monthly coincident peaks. Boise argues that the transmission system is built to only meet peak demand and not the energy needs of its customers.

Q. How does Boise's proposal affect the COS results and compare with the Company's filed COS study?

A. Scenario 5 in Table 1 above illustrates the impact on COS results based on Boise's recommendation. As expected, the residential class (being a lower load factor customer class) would receive a large increase in its COS while the rest of the customer classes would experience a decrease compared to the Company's approach.

Q. Do you agree with Boise's methodology for classifying and allocating generation and transmission costs?

A. Not at this time but I do agree Boise's methodology could be explored further. As I have addressed in my direct testimony and earlier in rebuttal of Staff, the Company's generation portfolio in the west control area consists of multiple types of generation sources such as coal, natural gas, hydro, and renewables and these resources produce the dual products of capacity and energy. The current methodology recognizes that production investments are utilized to meet peak demand and supply energy to customers. On a near-term basis, the only costs that will vary with energy use are net power costs.

I find it reasonable to classify a portion of transmission costs as energy related. For instance, FERC Account 565 (Wheeling) is a net power cost account that could be considered a variable cost in the same manner as Boise proposes the treatment of other net power cost accounts. Further, the Company has historically viewed the transmission system as an extension of the generation system. The National Association of Regulatory Utility Commissioners (NARUC) Cost Allocation Manual simply states:

> After transmission costs are separated into appropriate demand or energy allocation categories, it is necessary to then select a method of assigning cost allocation responsibility to various customers. In general, customers are allocated a portion of the fully distributed (embedded) cost of the transmission system on a basis similar to the way production costs are allocated. The reason for this is that the transmission system is essentially considered to be an extension of the production system, where the planning and operation of one is inexorably linked to the other. Thus, the major factors that drive production costs, it is argued, tend to drive transmission costs as well.[9]

Overall, when looking at the Company's entire generation portfolio, I do agree that more generation costs could be classified as demand related as is evident by the capacity factors of all generation sources in Table 2 above. A 50/50 demand/energy split is supported by the fact that the overall capacity factor of generation resources included in the west control area was approximately 51 percent for 2013.

Q. Why does the Company use 100 summer and 100 winter peaks for allocating generation and transmission costs?

A. Historically, the Commission has expressed a desire for a wider range of coincident peak hours for the allocation of these costs. The Commission has stated:

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[9] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, (January 1992), p. 75.

> Generally, the proper period over which to allocate the demand-related costs of peaking resources is the hours when they are expected to be used. The 200 hour proposal by the company is reasonably representative of the system peak and the actual resources put into place to serve that peak.[10]

In Docket UE-100749, Industrial Customers of Northwest Utilities (ICNU) proposed using the coincident peaks that were within 5 percent of the annual system peak. In its order, the Commission rejected this methodology by stating:

> As we have in the past when presented with a precise revision to peak demand, we conclude that this is too narrow a range. We agree with PacifiCorp that ICNU's proposal could produce volatility in results depending on the test period. While it is reasonable to allocate the costs of peaking resources based on the hours those resources will actually be used to serve load, the allocation method should be flexible enough to incorporate the variable peaks experienced in Washington. PacifiCorp experiences both a summer peak and a winter peak, and its proposal to include 100 summer hours and 100 winter hours to determine peak demand recognizes how resources are used.[11]

Q. Is the Company's methodology similar to Boise's four coincident peak methodology?

A. The Company's current methodology of allocating demand-related costs is similar to Boise's proposal while wholly embracing the Commission's desire for a wider range of peaks that represent a summer and winter peaking system. For instance, when taking a closer look at the 100 summer and 100 winter peaks, the Company currently uses three summer months and three winter months for allocating demand-related costs. Table 6 illustrates that a large majority of the 200 peaks (191 out of 200) fall within July, August, December, and January, the same months proposed by Boise.

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[10] *Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499 and UE-921262, Ninth Supplemental Order on Rate Design Issues at 12 (August 17, 1993).

[11] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order No. 06 at 104-105 (Mar. 25, 2011).

Table 6

Season	Month	Peaks
Summer	July	80
Summer	August	12
Summer	September	8
Winter	December	82
Winter	January	17
Winter	November	1
Total		200

Q. Please summarize your position on COS.

A. The Company's primary objective for COS is to find a balanced outcome between different competing methodologies and to achieve a sustainable approach that the Company will be able to apply consistently across the years in order to avoid COS swings from case to case. A number of methodologies may be considered when assigning cost to different rate classes. Some methodologies will benefit some customer classes while other methodologies will benefit others. In light of these considerations, the Company believes it's COS study fairly assigns cost and achieves balanced results.

RATE SPREAD

Q. Based on the rebuttal revenue requirement filed in this case, what is the Company's rate spread proposal?

A. After reviewing the range of positions on COS results, the Company makes no change to the proposed rate spread methodology as filed in my direct testimony. Specifically, the Company proposes to: (1) allocate an increase based on one-half of the overall increase to the schedules that the cost of service study indicates require a significantly smaller revenue increase (Schedules 24, 40, and lighting schedules); and (2) the remaining increase is then spread equally to the rest of the rate schedules.

Exhibit No. JRS-16, Table A (page 1), shows the effect of the proposed rebuttal base rate increase of $31.9 million. Table B (page 2), shows the effect of updated deferral costs of $5.9 million discussed in Ms. Siores's rebuttal testimony, which the Company proposes to recover through Schedule 92, Deferral Adjustment. Table C (page 3), shows the combined effects of the requested rebuttal base revenue increase and the amortization of the rebuttal deferrals in Schedule 92.

As discussed above, in light of the range of positions on COS results, the Company continues to believe the proposed rate spread reasonably balances the interests of all parties as well as the cost of service. Public Counsel generally supported the Company's proposed rate spread.

Q. Staff, Boise, and Wal-Mart propose modifications to the Company's rate spread proposal. Please respond.

A. Table 7 shows each party's proposed increase by rate schedule as a percent of the overall increase.

Table 7

Proposed Increase as a Percent of Overall Increase					
A	B	C	D	E	F
Schedule No.	Description	Company	Boise	Staff	Wal-Mart
16	Residential	112%	112%	150%	112%
24	Small General Service	50%	46%	0%	68%
36	Large General Service <1,000 kW	112%	112%	70%	100%
48T	Large General Service >1,000 kW	112%	111%	100%	100%
48T	Large General Service Dedicated Facilities	112%	112%	150%	112%
40	Agricultural Pumping Service	50%	71%	0%	68%
15,52,54,57	Street Lighting	50%	55%	0%	68%

Staff proposes a rate spread based on each rate schedule's relative proportion to COS, or parity ratio. Similar to the Company, Staff proposes higher increases to the schedules that are below COS and a smaller increase to general service, however, Staff proposes no increase to small general service, agricultural pumping and street lighting schedules.[12] Staff's proposal attempts to move all schedules to within five percent of parity,[13] whereas the Company's proposal made more moderate movements to COS for all rate schedules.

Boise proposes no rate schedule receive an increase greater than 1.12 times the overall average, which results in an increase equal to the Company's for the residential and large general service rate schedules. The residual increase would be allocated to the other schedules based on their relative parity to COS.

Wal-Mart proposes the same increase to residential and Schedule 48 Dedicated Facilities with the residual allocated to all other rate schedules based on their relative parity to COS.

In light of the parties' proposals, the Company's proposed rate spread is a reasonable compromise that makes movement to COS for all rate schedules.

RATE UNBUNDLING

Q. In your direct testimony the Company proposed to unbundle rates by function when developing rates. Did the Company prepare unbundled rates for this rebuttal filing as well?

A. Yes. As explained in my direct testimony, the Company proposes to unbundle rates by function—generation, transmission, and distribution—in the tariff and has used the same approach for the updated proposed rates in this rebuttal filing. Unbundling provides for greater transparency between COS and rate design. No party appears to

[12] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 22.
[13] *Id.*

oppose how the Company proposed to unbundle rates, although no party other than Wal-Mart remarked on it in testimony. Wal-Mart supports the Company's proposal to unbundle rates and reflect the unbundled rates in the tariff; however, Wal-Mart recommends that the Commission require the Company to reflect the unbundled rates in customer bills or set a timeframe for the Company to implement the changes required to do so.[14]

Q. What is the Company's response to Wal-Mart's proposal to show the unbundled rates on customer bills?

A. The Company supports increased transparency in rates and accordingly is willing to work with parties to add greater cost transparency on bills for non-residential customers through unbundled rates. For residential customer bills, it will be important to incorporate customer education prior to making changes on the bills in order to minimize customer confusion. As such, any roll out in reflecting unbundled rates on bills will need to be staggered between residential and non-residential customer bills.

Q. Is the Company proposing any other tariff changes from its initial filing for the unbundled rates?

A. Based on a comment made by a customer at the public hearings, the Company will modify the tariff pages that show the unbundled rates to spell out the acronym NPC, or net power costs, or otherwise define the term on the tariff pages. The Company agrees with the customer's comment that this cost element can be articulated in a better manner on the tariff page.

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[14] Responsive Testimony of Steve W. Chriss, Exhibit No. SWC-1T at 9.

RESIDENTIAL RATE DESIGN

Q. Please summarize Staff's proposed residential rate design.

A. Staff proposes to increase the monthly residential basic charge from $7.75 to $13.00. The remainder of the allocated increase will be recovered through the energy charges. Staff proposes modifying the inverted block energy charges by increasing the size of the first block from 600 to 800 kilowatt hour (kWh), setting a second block from 801-1,700 kWh and adding a third block for kWh usage over 1,701. The current residential block structure consists of two blocks: one for the first 600 kWh and the second for all additional kWh.

Q. Please summarize Public Counsel's, the Energy Project's, and TASC's proposed residential rate designs.

A. Public Counsel and the Energy Project recommend no increase to the current residential basic charge of $7.75 per month. TASC recommends a maximum residential basic charge of $9.00. No other parties address the residential block structure.

Q. Is the Company proposing any changes to the residential rate design proposed in your direct testimony based on the testimony from Staff, Public Counsel, TASC, or the Energy Project?

A. No. The Company continues to support an increase in the basic charge to $14.00 per month for Schedule 16 and $8.75 per month for Schedule 17. I will show that the $14.00 per month basic charge is supported using both the Company's and Staff's calculations and is necessary to address the growth in distributed generation (DG) and the changing industry landscape resulting from increased customer generation. The

Company also proposes to retain the current inverted energy block rate structure. This rate design represents the best balance between cost causation, equity, economically efficient price signals for conservation, and minimizing customer impacts, particularly for low income customers. Staff's proposed changes in the rate design for the energy block rates are contradictory to its stated intent of encouraging conservation, are not cost-based, and will not improve fixed cost recovery for the Company. Other parties' proposals to limit the increase in the basic charge continue to ignore cost causation in the generic name of gradualism. In the following sections I will first respond to parties' testimony on the customer charge, followed by my response to Staff's proposed change in the block rate structure. Exhibit No. JRS-17 contains the proposed prices and billing determinants used in calculating the proposed prices. Exhibit No. JRS-18 contains monthly billing comparisons for the revised proposed prices at different usage levels for each rate schedule.

<u>Residential Basic Charge</u>

Q. Please explain the Company's proposed residential basic charge.

A. The Company's rebuttal filing continues to support a cost-based basic charge of $14.00 per month. The proposed charge is derived from the filed COS study, Exhibit No. JRS-15. As explained in my direct testimony, fixed costs (i.e., costs that do not significantly vary with usage) are appropriate costs to include in determining the level of the residential basic charge. In this proceeding, the Company has proposed to limit these fixed costs to those related to local distribution and retail service costs. The distribution costs include meters, service lines, transformers, poles, and conductors. The retail service costs include meter reading, billing, and customer services. The

COS study supports a basic charge of $28.00 for these costs. The Company's proposal is to increase the current basic charge of $7.75 per month to $14.00, which would collect half of these costs in the monthly basic charge. Moving the basic charge to collect half of these costs fairly recognizes that a minimum level of these facilities and services is required for the provision of electric service to any residential customer, regardless of size.

Q. How does Staff support its proposed $13.00 residential basic charge?

A. Staff similarly relies on the COS to support its $13.00 customer charge. In its basic charge calculation, Staff includes the full costs for retail services and distribution facilities for meters, service lines, and transformers in its average cost per customer calculation.

Q. Using the Company's proposed revenue requirement, what basic charge is supported when using the same cost elements that Staff included in its residential basic charge?

A. As shown in Exhibit No. JRS-19, a basic charge of $14.10 is supported using Staff's cost elements but updated to reflect the Company's proposed revenue requirement. Staff's method shows another way that a $14.00 customer charge is justified and cost based.

Q. Are there additional policy justifications for increasing the basic charge?

A. Yes. As described in the testimony of Mr. R. Bryce Dalley, the Company, and the electric utility industry as a whole, is in a period of significant transformation. Many states, including Washington, have adopted new laws and policies designed to reduce reliance on traditional, fossil fuel generators in favor of renewable and DG.[15] These policy changes have created, and will continue to create, major challenges for the Company. The Company's proposed basic charge is intended, in part, to support the Company and ensure that the Company is well positioned to respond to growing customer generation. For example, since 2013, the test period for this case, there has been a 60 percent increase in the number of net metering customers through October 31, 2014.

Q. How does the Company's proposed basic charge support the Company in the face of increasing DG?

A. A basic charge that more accurately reflects the Company's actual fixed costs, as recommended by the Company and Staff, helps to mitigate cost-shifting caused by the growth in customer generation and ensures that the Company has a reasonable opportunity to recover its fixed costs from customer generators.

Q. Has the Commission recognized that customer generation can result in cost-shifting to non-generating customers and compromise a utility's ability to recover its costs?

A. Yes. In a 2011 report analyzing the impact of DG, the Commission observed that the development of laws and policies to promote DG must protect customers, including protection from cost-shifts between rate classes and types of customers, and ensure sufficient returns for utility investors.[16]

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[15] *See, e.g., In the Matter of Amending and Repealing Rules in WAC 480-108 Relating to Electric Companies-Interconnection With Electric Generators*, Docket UE-112133, Interpretive Statement Concerning Commission Jurisdiction and Regulation of Third-Party Owners of Net Metering Facilities (July 30, 2014).

[16] *UTC Report on the Potential for Cost-Effective Distributed Generation in Areas Served by Investor-Owned Utilities in Washington State*, Docket UE-110667 at 5 (October 7, 2011). The Commission observed that, "net metering provides a type of incentive for individual consumers because it shifts costs from the individual

Q. Is the Company's recommended basic charge consistent with the average residential basic charges in Washington?

A. Yes. The average residential basic charge in Washington is $15.69 per month. Exhibit No. JRS-20 shows the current residential basic charges for other Washington utilities. In addition, it is my understanding that the Wisconsin Public Service Commission recently approved an 83 percent increase in the fixed charge for customers of Wisconsin Public Service Corporation, increasing the fixed charge to $19.[17]

Q. What justification does TASC give for its maximum residential basic charge of $9.00?

A. TASC argues that the only costs that should be included in the basic charge are those for retail services, meters, and service lines. TASC also argues that gradualism should prevail in any decision to raise the basic charge.

Q. What justification does Public Counsel give for maintaining the basic charge at its current level?

A. Public Counsel argues that only marginal customer costs, which only include costs that vary as a result of a new customer, should be recovered through the customer charge. Accordingly, Public Counsel includes only services, meters and incremental billing and accounting costs in the customer charge.

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ratepayer to the utility, and ultimately to the other ratepayers of that utility, due to the need to maintain sufficient capacity to meet that individual customer's load while his or her net metered system is not generating electricity." *Id.* at 29.

[17] http://www.jsonline.com/business/state-regulators-approve-83-in-green-bay-utilitys-fixed-charge-b99385986z1-281824701.html.

Q. Public Counsel excludes corporate overhead costs from its calculation of a residential basic charge.[18] Do you agree that these costs should be excluded?

A. No. First, to be clear, the corporate overhead costs included in the basic charge calculation are only the portion of overhead costs that are allocated to customer-related distribution costs in the COS study; they are not all overhead costs as may be inferred from Public Counsel's testimony.

Second, Public Counsel's only rationale for removing these costs is that the Company is "in the business of providing electricity to meet the energy needs of its customers" and that "customers do not subscribe to PacifiCorp's services simply to be 'connected.'"[19] This is an inadequate rationale. Overhead costs are a necessary part of doing business. The Company cannot provide electricity to customers unless they are connected. The costs of connecting and serving those customers—through meters, services, poles, conductors, transformers, and customer services—cannot exist without overhead costs. It is appropriate to include the allocated share of overhead costs for the elements included in the calculation of the basic charge.

Q. What justification does the Energy Project give for maintaining the customer charge at its current level?

A. The Energy Project generally opposes increases to the basic charge on the grounds that it diminishes a customer's ability to control their bill. As described below, the vast majority of a typical customer bill will still reflect variable costs over which customers have some control.

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[18] Testimony of Glenn A. Watkins, Exhibit No. GAW-1T at 27:12-14.
[19] *Id*. at 28:1-4.

Q. Public Counsel and TASC argue that poles, wires, and distribution transformers represent marginal costs that are variable in nature. Do you agree?

A. No. Poles and conductors (P&C) and transformers, along with other distribution assets such as meters, services and substations are fixed costs that are required to provide a minimum level of service to all customers. These assets will not vary in cost in the near term; once installed these are long-term, fixed investments necessary for the provision of service to customers. The most recent depreciation study approved by the Commission shows depreciation lives of 52, 60, and 43 years for poles, conductors, and transformers, respectively.[20] Accordingly, these investments are not variable in nature, as asserted by Public Counsel and TASC. The costs for these facilities do not go away when usage levels decrease, whether the decrease is related to weather, behavioral changes, the adoption of energy efficient appliances, or the installation of DG. At a minimum, recovering half of these costs through the basic charge more fairly balances cost recovery for the Company and the investments necessary for the provision of electric service.

Q. How do Public Counsel and TASC propose that P&C and transformer costs be recovered by the Company?

A. Both Public Counsel and TASC propose that P&C and transformers be recovered through the volumetric energy charge for residential customers. However, even the NARUC Cost Allocation Manual recognizes that there is no energy component for distribution costs, stating "Because there is no energy component of distribution

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[20] *See* FERC Account 364 (Poles, Towers, and Fixtures), Account 365 (Overhead Conductors), and Account 368 (Transformers) in Docket No. UE-130052, Order Granting Accounting Petition (December 27, 2013).

related costs, we need consider only the demand and customer components."[21] Accordingly, for most other rate schedules these costs are recovered through a combination of basic charges and demand charges. Without a demand charge component for residential customers, a balance between the basic charge and the energy charges represents the fairest, most cost-based rate design.

Q. Are poles, conductors, and transformers a customer-related component of distribution line transformers?

A. Yes. Like a meter or service drop, there is a large portion of the distribution line conductors and distribution transformer costs that are fixed and do not vary with the capacity of the equipment. A large portion of the total cost of distribution equipment is associated with the embedded cost for manufacturing equipment, production processes and transportation of material, which is required to meet federal safety standards and/or industry manufacturing standards. This cost is fixed and does not vary with capacity. For example, a 25 KVA single phase pad-mount transformer and a 50 KVA single phase pad-mount transformer, which are commonly installed in residential subdivisions, have average installed costs of $5,212 and $5,598, respectively. Although, the 50 KVA transformer provides double the demand capacity of the 25 KVA transformer, it only costs about 5 percent more. Clearly, a large proportion of the cost of these transformers in this example do not vary with capacity and are fixed costs necessary to serve customers. A similar relationship exists for distribution poles and distribution line conductors in that the large majority of these equipment costs are customer-related fixed costs associated with

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[21] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, (January 1992), p. 89.

manufacturing equipment, production processes and transportation of material. Without these fixed cost components, the base utility system infrastructure required to provide safe and reliable service to customers, independent of demand, would not be there.

Q. For perspective, how do the different cost elements for service to an average residential customer compare to how costs are recovered from the average residential customer?

A. Table 8 below shows what costs make up an average residential bill. Of these costs only net power costs, which make up approximately 42 percent of the residential costs, will truly vary in the near term with changes in usage. The other cost components, which make up 58 percent of the total residential costs, are more fixed in nature; the only thing that changes in the near term for the non-net power costs is who pays for those costs. In contrast, Table 9 below shows how costs are recovered through charges on the bill. This shows that with the proposed rates, only 11 percent of the average residential customer's bill is fixed with the remaining 89 percent is variable.

Table 8

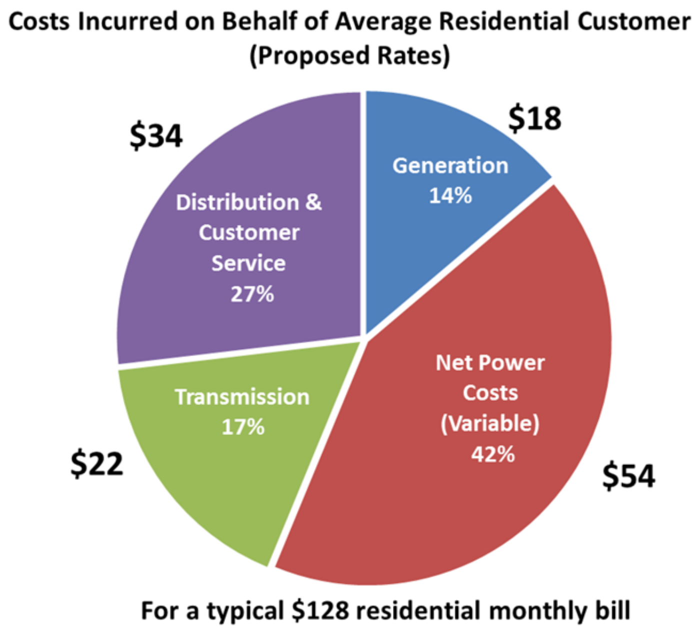
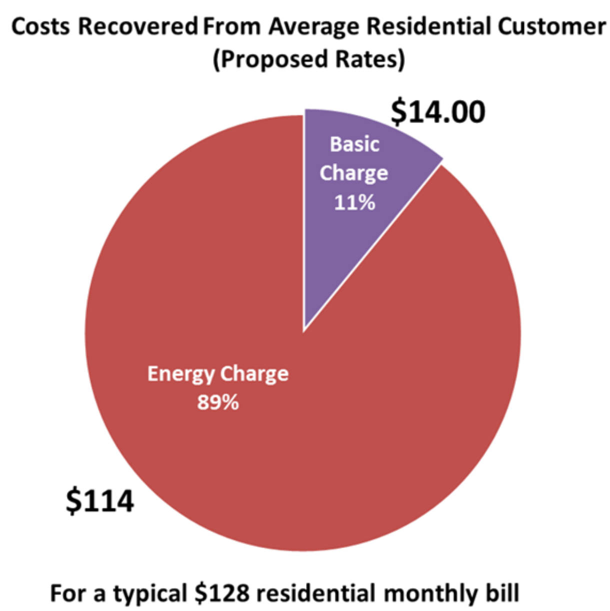


Table 9



Q. Public Counsel states that pricing structures that are weighted heavily on fixed charges are inferior from a conservation and efficiency standpoint than pricing that requires consumers to incur more cost with additional consumption.[22] Is the proposed residential pricing structure heavily weighted on fixed charges?

A. No. In contrast, the proposed pricing structure is heavily weighted toward variable charges, as is clearly show in Table 9 above.

Q. Public Counsel, the Energy Project and TASC argue that the proposed increase in the residential customer charge dampen customer's price signal for conservation. Do you agree?

A. No. As I showed in my initial testimony, under the Company's proposed rates, 89 percent of the average customer's bill will still be based on volumetric energy rates. For a small user half the size of an average user, 77 percent of the bill is related to energy charges; and a high user twice the size of an average user will have 95 percent of the bill related to energy charges. As previously noted, the proposed charge recovers only a portion of the distribution and customer service costs with the remaining costs in the energy rates, along with *all* of the costs related to generation and transmission. All residential customers—and high use in particular—will continue to have a strong motivation to conserve or pursue energy efficient technology and achieve bill savings.

[22] Testimony of Glenn A. Watkins, Exhibit No. GAW-1T at 24:2-5.

Q. Public Counsel and TASC argue that the Company's proposed residential customer charge violates the Commission's policy for gradualism. Do you agree?

A. No. The Company's proposal does take into account the principle of gradualism. The proposed charge does not include the fixed costs related to transmission and generation and only includes half of the distribution and retail costs in the proposed charge. The generic, nonspecific argument of gradualism is insufficient to perpetuate on-going intra-class cross-subsidies. Aligning rate design with underlying cost causation improves efficiency because it sends proper price signals and ensures equity among customers by eliminating subsidies. Moreover, the increase in the basic charge is neither unduly impacting small use customers, compromising the price signal for efficiency, nor is out of line with what other residential customers pay across the state.

Q. Mr. Watkins uses the Federal Energy Regulatory Commission's (FERC) adoption of a "Straight Fixed Variable" (SFV) pricing method in Order 636, which was intended for natural gas transmission pipeline companies, to suggest that the Company's proposed rate structure could hinder energy efficiency goals.[23] Do you agree that this is an appropriate comparison?

A. No. This comparison is irrelevant for many reasons. First, the Company did not propose a SFV pricing structure. The Company is merely proposing an increase in the residential basic charge to better reflect customer-related fixed costs. A SFV pricing structure would result in a considerably larger fixed customer charge

[23] Testimony of Glenn A. Watkins, Exhibit No. GAW-1T at 22-23.

component than the Company's proposal of $14.00, after taking into account all generation, transmission and distribution related fixed costs. Second, the purpose of FERC's adoption of SFV for pipeline companies was to eliminate potential distortions in pipeline rate structures and stimulate competition at the wellhead for a national gas market. FERC's action for natural gas pipelines is simply not analogous to electric residential consumers and rates. The purchasing decisions by gas transportation customers and residential electricity customers are very different in scale and scope.

Residential Energy Block Charges

Q. Please summarize your concerns with Staff's proposal to revise the energy charge block structure to move the first block from 600 kWh to 800 kWh per month and add a third block for usage over 1,700 kWh.

A. First, Staff's proposed energy rate design is inconsistent with its stated intent "to create a clearer price signal for residential customers to be more efficient and to follow the principles of cost causation."[24] In actuality, Staff's proposed rates will send a confusing price signal and may encourage increased consumption to a large number of customers, and is not cost-based but merely punitive for electric heat customers.

Second, Staff ignores the fact that the Company's current rate design already sends a significant price signal to large users, particularly when compared to the other investor-owned utilities in Washington. Additionally, the current first block at 600

[24] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 27:18-20.

kWh per month already represents a reasonable level for essential end uses such as lighting and appliances for Washington.

Third, with the growth in customer generation, it is important to consider unintended consequences of rate design. Staff's proposed tail block would send an uneconomic price signal and benefit to customers with DG which will contribute to cost shifting to customers without DG.

Q. Before addressing your concerns with Staff's proposed rates, do you have other comments or corrections to Staff's testimony?

A. Yes. First, I would just point out that Staff's residential rate calculation uses residential billing units inconsistent with the test year billing units used by the Company in this proceeding for both the calculation of present revenues for the results of operations and the development of residential rates. It appears that Staff left out the number of and net billed kWh for residential net metering customers in its billing units and double counted the temperature adjustment for residential Schedule 18. This results in different billing determinants and a different present revenue than reflected in the results of operations. Since this appears to be an inadvertent error by Staff in the preparation of its filing, the Company's billing units should be relied on for calculation of final rates in compliance with a Commission order in this proceeding.

Second, Staff incorrectly states that the Company's rate proposal would actually decrease rates for the highest residential users.[25] Staff refers to Exhibit No. JRS-9 in support of this statement. However, Staff apparently misunderstands this

[25] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 5:1-2.

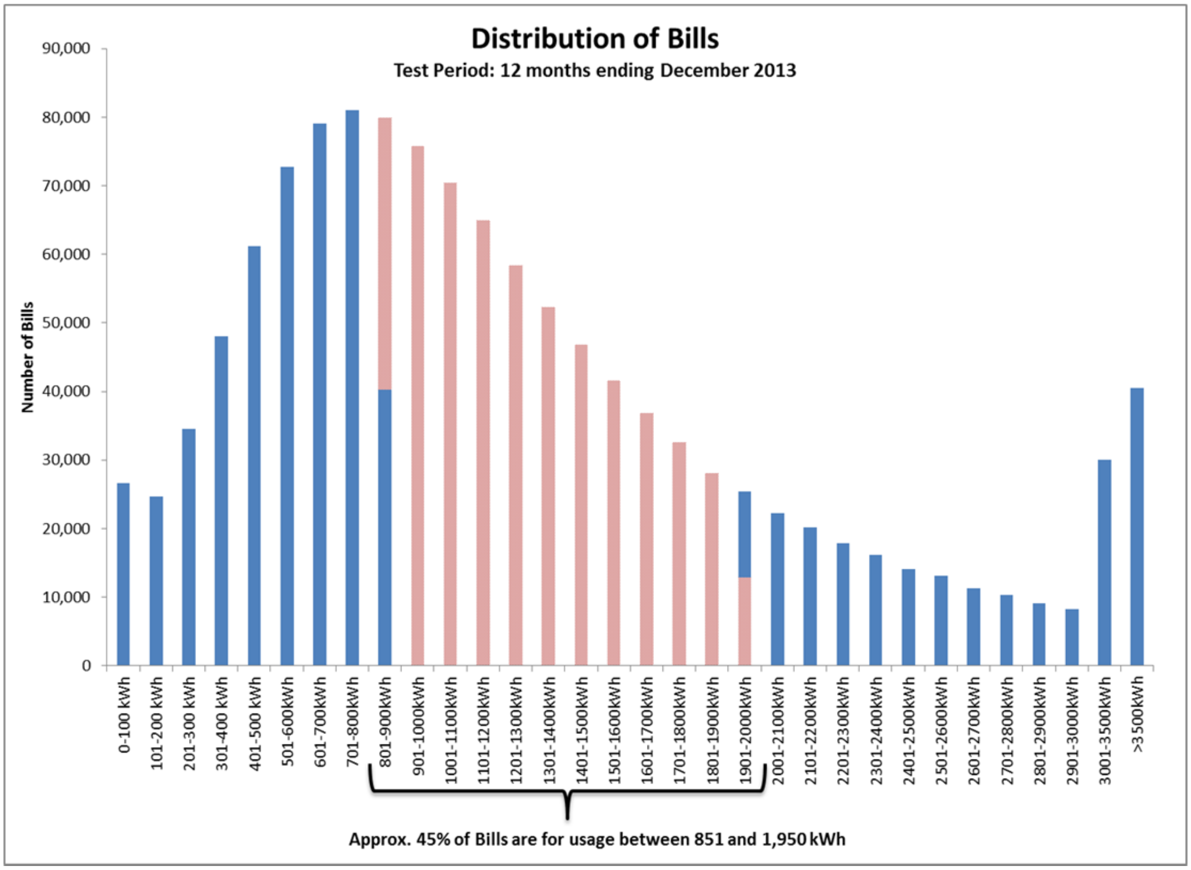
exhibit. Exhibit No. JRS-9 shows a comparison of monthly bill impacts for small, average, and large users under the Company's proposed rates versus a scenario where the basic charge remained unchanged and the residential increase was entirely applied to the energy charges. It does not show the impacts of the Company's proposed rates that include an increase to both the basic charge and energy charges. With the Company's proposed rate design, large users will see a rate increase, as is clearly shown on page 1 in Exhibit No. JRS-7 for the initial filing and on page 1 in Exhibit No. JRS-18 for this rebuttal filing.

Q. Please explain your first concern that Staff's proposed rate design is consistent with its intent to send a clearer price signal.

A. Staff's proposed residential rate design actually reduces bills for a significant number of customers, which would produce a confusing price signal at a time when costs to the residential class are increasing. Table 10 below shows that 45 percent of customer bills—those with usage between 851 and 1,950 kWh per month—would see a reduction in their bills. These bill reductions widely span the average customer usage at 1,300 kWh per month. This reduction is due to Staff's lower rate for usage between 800 and 1,700 kWh and the shift in costs to the highest use customers compared to the current rate design. Staff readily acknowledges this bill reduction for average customers[26] but fails to explain or provide any analysis to support lower costs for average users.

[26] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 29:3-12.

Table 10

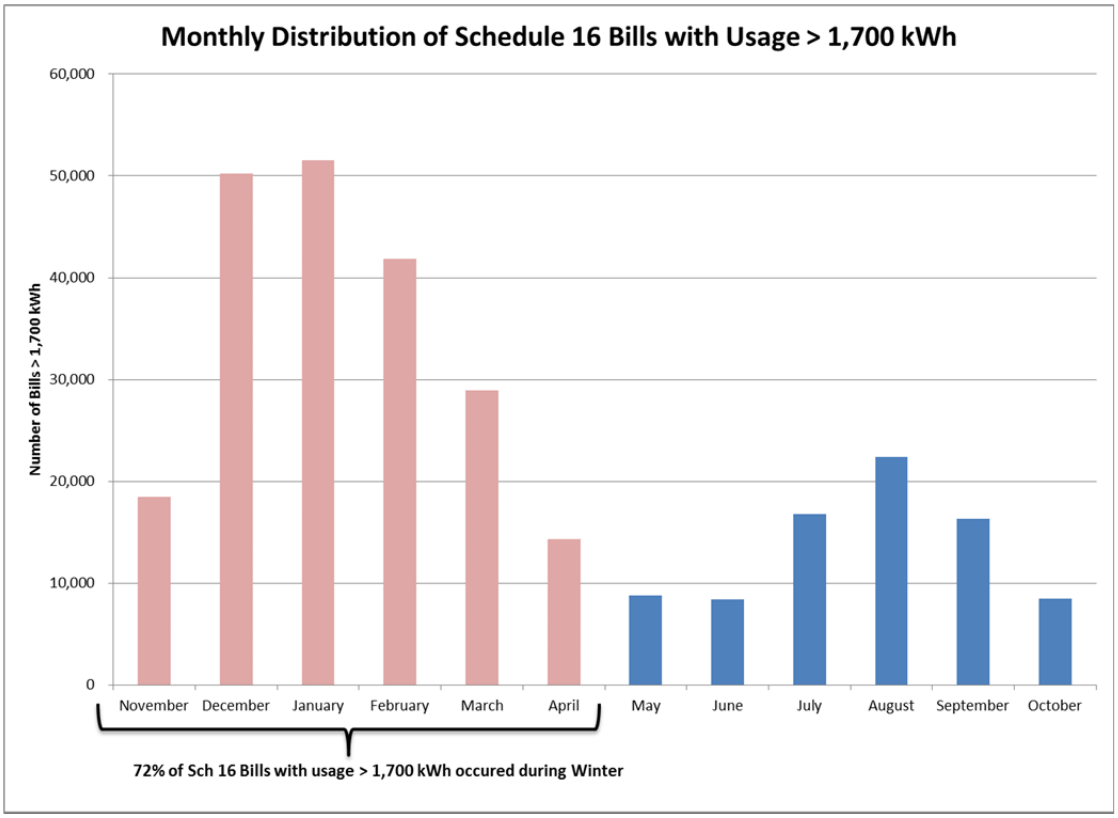


Q. Does Staff provide any cost-based analysis to support revising the current two block rate design to include a third block for all usage over 1,700 kWh?

A. No. Staff merely states that it is cost-based but Staff's only analysis is to show that average usage during four winter months (November - February) is approximately 1,700 kWh.[27] Table 11 below shows the monthly distribution of bills over 1,700 kWh for Schedule 16 customers. This table shows that approximately 72 percent of Schedule 16 bills that exceeded 1,700 kWh (over 205,000 bills) occurred during the winter months of November through April. This new rate block therefore appears to be an attempt to penalize electric heat customers.

[27] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 28:17-20.

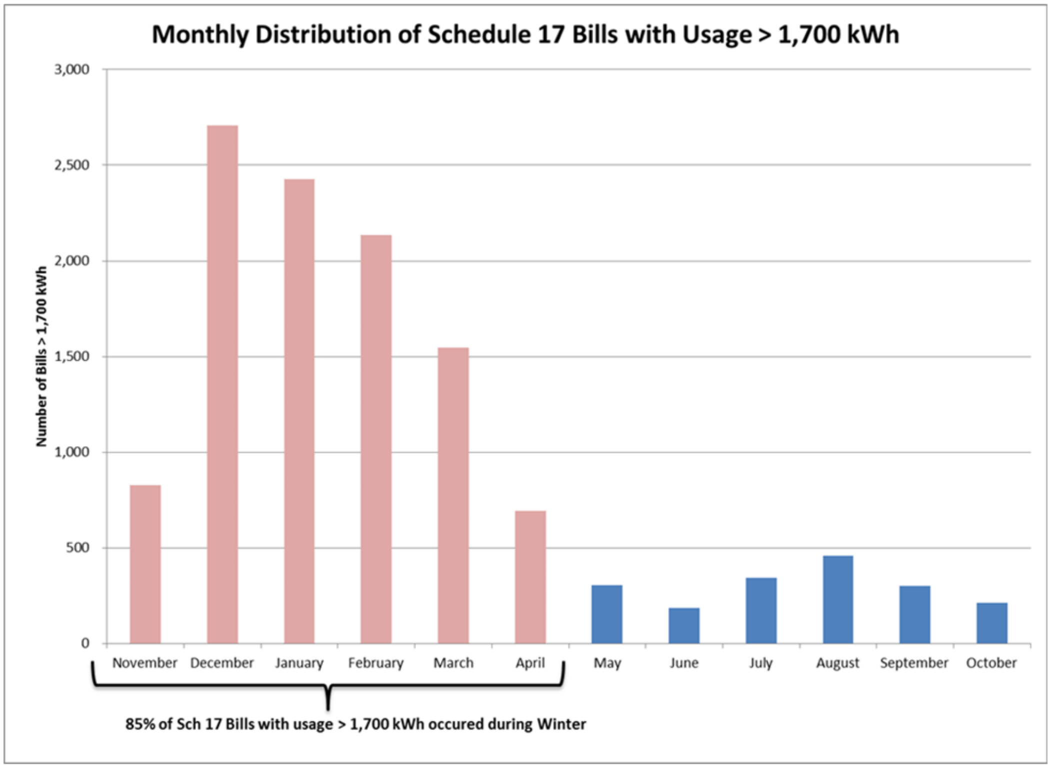
Table 11



Q. Will low income customers be adversely impacted under Staff's proposed rate design?

A. Yes. I'm concerned that Staff's rate design proposal to add a third block for usage over 1,700 kWh per month will have a greater impact on low income customers. Table 12 below is similar to Table 11 above except Table 12 shows the percent of customers on Schedule 17, the Company's Low Income Bill Assistance Program (LIBA), who have bills that exceed 1,700 kWh per month. This table shows that 85 percent of Schedule 17 low income bills exceeded 1,700 kWh (over 10,000) in the winter. For low income customers in particular, it is likely harder to find alternatives to electric heat that would allow them to manage their bills without compromising comfort and health.

Table 12



Q. Does Staff provide any analysis about how customers may respond to its price signal for the third block?

A. Staff provides an analysis of the potential reduction in usage for the third block based on price elasticity of demand. Staff uses elasticities for residential customers in Washington from a 2006 National Renewable Energy Laboratory report and calculates a potential short-run load reduction of 0.23 percent or 3,759 MWh and a long-run load reduction of 0.47 percent or 7,660 MWh in its proposed third block.

Q. Do you have any concerns with this analysis?

A. Yes. Staff only applied this elasticity analysis to usage over 2,000 kWh. Staff did not apply this same analysis to the usage levels that would experience a bill reduction under Staff's proposed rate design. Elasticity works in both directions—a reduction in price may result in an increase in demand and an increase in price may result in a reduction in demand—and the elasticity factors used by Staff are not exclusive to high usage.

Using Staff's methodology, the Company recalculates Staff's long-run reduction due to elasticity to be 8,523 MWh, or 0.53 percent, based on the bill changes for all customers. This includes a net increase of 2,674 MWh for the customers with usage between 851 and 1,950 kWh per month who would see a bill reduction under Staff's proposal. In contrast, under the Company's proposed rates, which balance the cost increase to all usage levels, the long-run reduction from elasticity would be 28,919 MWh, or 1.8 percent of load. Even after attempting to account for the difference in the overall revenue requirement proposed by the Company and Staff, the Company's proposed rate design results in a higher overall reduction in use since a higher rate would apply to more kWh. These calculations are shown in Exhibit No. JRS-21.

Q. Staff argues that under its rate design the Company will face less risk of fixed cost recovery. Do you agree?

A. No, I disagree for a couple of reasons. For one, Staff's table on page 28 in Exhibit No. JBT-4 that purports to show improved revenue stability from Staff's rate design is misleading because of the change in kWh in the 1st block. By increasing the first block from 600 kWh to 800 kWh per month, the percent of revenue recovered in that block under Staff's proposal goes up because there are more kWh in that block, not because there is more stable cost recovery. The percent of revenue from the basic charge and usage under 600 kWh is similar under both the Company's proposal and Staff's proposal. The percent of revenue from usage over 1,700 kWh, however, is the key difference with Staff's rate design resulting in 22 percent of revenue compared to the Company's 18 percent.

Q. Would weather influence usage in this tail block, and therefore influence the Company's cost recovery?

A. Absolutely. Since usage over 1,700 kWh per month is largely tied to electric heat in winter, then temperature will influence usage and therefore recovery of costs. Rates are designed based on revenue and usage that has been normalized for weather, however, weather is hardly ever "normal". Exhibit No. JRS-22 shows the temperature adjustments that have been applied to normalize residential usage in the last five cases. This exhibit shows that temperature adjustments for the residential class range between a reduction to test period load of 84,467 MWh and $5.6 million in revenue in UE-100749 to an increase of 46,034 MWh and $3.2 million in UE-111190. Winter temperature is the largest driver of these adjustments and represents 70 percent and 86 percent, respectively, of the total adjustments to the test period load for these cases. Pushing more revenue recovery into this temperature sensitive usage block will make the Company more subject to weather for the recovery of fixed costs.

Q. Staff argues that only a small portion of fixed costs are in the third block rate. Do you agree?

A. No. As I previously noted the only costs that will vary with changes in consumption in the near term are net power costs. Staff's proposed third block rate is approximately 12 cents/kWh. Net power costs, however, are approximately 3.7 cents/kWh on average. So while Staff argues that "any reduction in usage in this block should strongly correlate with a reduction in the Company's energy-based expenses such as fuel and purchased power,"[28] there is an over 8 cents/kWh differential between the rate and variable net power costs. For any reduction in usage, the Company will under recover 8 cents in other costs.

Q. Please explain how the current two-block rate structure already sends a significant price signal to large use customers.

A. The Company's current residential rate design already reflects a steeply inverted block rate that results in a higher average price for large users. As Table 13 below shows, the Company's current second tier energy rate is 58 percent higher than the first tier. The Company's rebuttal proposal retains this differential. For perspective, Table 13 compares the Company's rates to the rates of the other investor-owned utilities in Washington.

[28] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 33:22 – 34:1.

Table 13

% Differentials between blocks	Company Proposal	Staff Proposal*	PSE Current	Avista Current
Basic Charge	$14.00	$13.00	$7.87	$8.00
Block 1 Rate (¢/kWh)	6.5800	6.4720	8.6692	7.3690
Block 2 Rate (¢/kWh)	10.4230	9.1700	10.5514	8.5730
Block 3 Rate (¢/kWh)	10.4230	11.9960	10.5514	10.0500
Block 1 Size	0-600	0-800	0-600	0-800
Block 2 Size	600+	800-1700	600+	800-1500
Block 3 Size		1700+		1500+
Block 1->2 Price Signal	58%	42%	22%	16%
Block 2->3 Price Signal		31%		17%
Block 1->3 Price Signal		85%		36%
Monthly Bill @ 600 kWh	$ 53.48	$ 51.83	$ 59.89	$ 52.21
Monthly Bill @ 1,300 kWh	$ 126.44	$ 110.63	$ 133.75	$ 109.82
Monthly Bill @ 3,000 kWh	$ 303.63	$ 303.25	$ 313.12	$ 277.71

*Reflects a 6.9% lower Residential Revenue Requirement than Company proposal

This shows that the second tier for Puget Sound Energy's (PSE) residential customers, which is also set for 0-600 kWh, is 22 percent higher than the first tier and results in a significantly flatter rate structure.[29] Avista, which has three residential energy tiers, has an even flatter rate structure with the second tier (for usage between 800-1500 kWh) only 16 percent higher than the first tier and the third tier only 17 percent higher than the second tier.[30] The difference between the first and third tiers for Avista is 36 percent, which is significantly less than the differential in the Company's current rate design. This all results in the differentials between the average rates for low and high users to be greater under the Company proposal than under the rate designs of PSE or Avista. However, based on average rate data for the 12 months ending June 2014 from the Edison Electric Institute (EEI), the Company

[29] *See* Puget Sound Energy, Inc., Tariff WN U-60, Schedule 7, effective November 16, 2013, and Schedule 141, effective January 1, 2014.
[30] *See* Avista Corporation Tariff WN U-28, Schedule 1, effective January 1, 2014.

has the lowest overall average rate of the three investor-owned utilities in Washington (Company – 8.21 ¢/kWh; PSE – 10.35 ¢/kWh; Avista – 8.74 ¢/kWh).

Staff's proposed rate design will increase the differential in the rate between the first and third blocks to 85 percent, resulting in bills for electric heat customers in Pacific Power's service area being close to or higher than bills for comparably sized customers at other utilities. For Pacific Power's customers that rely on electric heat in winter, this begs a question of fairness, particularly in light of the fact that Pacific Power is the lowest overall cost utility when compared to Avista and PSE. Finally, because 85 percent of Pacific Power's low-income bills over 1,700 kWh occurred during the winter, the time during which electric heat is critical, these customers would be disproportionately affected.

Q. In addition to creating a third block, Staff also proposes to increase the size of the first block from 0-600 kWh to 0-800 kWh because Staff argues that usage under 800 kWh is inelastic and that customers have limited capacity for efficiency gains when it comes to basic needs.[31] Do you agree with this proposal?

A. No. The Company's energy efficiency programs target many types of end uses—not just electric heat—so altering this rate design may actually undermine those energy efficiency program efforts. Moving more usage into the first block reduces the conservation price signal because more consumption can occur at a lower rate. There is no compelling reason to send this confusing price signal to customers, particularly in light of Washington Initiative I-937. It also doesn't reflect on-going changes in national and state codes and standards for end-uses and buildings that are driving

[31] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 28:1-13.

down use. For instance, the Energy Independence and Security Act of 2007 laid out changes in Federal Lighting Standards that have phased out incandescent bulbs down to 40 watts by 2014. This change in lighting standards has promoted the use of compact fluorescent and light emitting diode bulbs that reduce energy usage over incandescent bulbs by up to 75-82 percent.

Additionally as I noted in my rebuttal to Staff's similar proposal in the 2013 Rate Case, using upper-end national data to reset the tier level is incompatible with Washington's (and the Pacific Northwest's) historically aggressive energy efficiency efforts and building codes and may not be reflective of what the less elastic essential end-uses are in the Company's Washington service area today. Table 14 below provides the end-use saturation levels and estimated kWh use by end use that was an input into the Company's conservation potential study used in the 2013 IRP. The end-use saturation levels come from the Company's recent residential consumption survey, which was filed with the Commission on July 31, 2014, in Docket UE-130043 in compliance with Order 05. This table shows that based on more current and localized data for the most common types of appliance end-uses and lighting are well under 600 kWh per month compared to the high end national HUD data used by Staff. Even with the addition of electric water heat, which has a relatively high level of saturation in the Company's Washington service area, a first block of 600 kWh is reasonable.

TABLE 14

Comparison of Estimated Appliance Use

	Est. Monthly kWh Usage		WA Survey
Type of Appliance	**HUD**	**2013 IRP WA**	**% of Saturation**
Lighting - standard plus specialty (30 units)		70	
Refrigeration		44	100%
Lighting and Refrigeration	250-400	114	
Electric Oven/Range	110	13	86%
Freezer		29	59%
Dishwasher		30	100%
Microwave		12	97%
Clothes Dryer		83	100%
TV		27	100%
DVD Player		2	72%
Computer		18	90%
Plug Load Other		48	
Lighting, Refrigeration, and Appliances	**360-510**	**389**	
Water Heater	340	233	72%
A/C / Cool Central	180	127	66%
Heat Central/Heat Pump/Heat Room	680	1141	56%

Q. Speaking of the residential consumption survey, has the Company evaluated the results to see if a discernable pattern emerges to characterize customers who have usage over 1,700 kWh per month?

A. Yes. The Company compared responses from customers who had a bill for usage over 1,700 kWh to responses from all customers. The responses are summarized in Confidential Exhibit No. JRS-23. Some of the interesting findings are:

- High usage customers are more likely to have electric heat.
- High usage customers are more likely to have a single-family home or a manufactured home.
- High usage customers are more likely to have more people in the home. (Q47)

- High usage customers are more likely to have a larger square footage home.
- High usage customers are <u>not</u> more likely to keep track of their usage, be aware of how many kWh they use, or be aware of the tiers. (Q35, Q38, 42).
- Over 50 percent of customers, including high usage customers, indicate that the tiers have not influenced their usage. (Q44).

Q. Please discuss your third concern about the unintended consequences of Staff's proposed rate design.

A. With the growing interest in customer DG and net metering, described above, the company believes major changes in rate structure need to carefully consider the unintended consequences of uneconomic price signals that such rate structures may create. With net metering, customers receive a benefit equal to the energy rate avoided for the DG output that offsets contemporaneous use. They also receive a benefit equal to the energy rate that is applied to the excess DG output during times when output exceeds consumption. The energy rates, therefore, become important price signals and incentives for net metering customers. With Staff's proposed rate design that creates a 12 cents/kWH rate (at its proposed revenue requirement) in the third block, that rate becomes an incentive or benefit for large customers either currently with or interested in DG. Because that rate includes fixed costs in addition to variable costs, (even if the company's proposed basic charge is approved) it will lead to greater cost shifting to other customers as DG grows.

While the Commission has an on-going investigatory docket, UE-131883, on the costs and benefits of DG, there has been no finding or determination on the costs and benefits at this time. Accordingly, a major revision to the current residential rate structure is premature without consideration of whether it sends a price signal consistent with the costs and benefits of DG, particularly in light of the Commission's prior observations in Docket UE-110667 on cost-shifting due to DG.

Q. On the topic of DG, how do you respond to Staff's discussion in response to your direct testimony that the Company is conducting a load research study for DG customers and may propose a new rate design in a future case?

A. I found Staff's response and recommendation confounding and inaccurate. First, I find it perplexing that Staff would prejudge a rate proposal, ask the Commission to prejudge it, and indicate a higher burden of proof would be required on something that hasn't yet been filed. The purpose of that part of my testimony was to inform the Commission that the Company is conducting load research to inform future rates. Unlike Staff, the Company is not asking the Commission to take any action on this topic at this time without the benefit of supporting data.

Second, Staff inaccurately characterized my testimony and the three-part rate design that includes a demand rate component. Staff states: "A three-part rate design includes the basic charge and volumetric usage charge that residential customers already pay, but adds a demand charge that assesses an additional fee based on the customer's peak usage during the billing cycle."[32] In actuality, a demand charge is not an additional fee assessed on top of what customers already pay. All rates for this

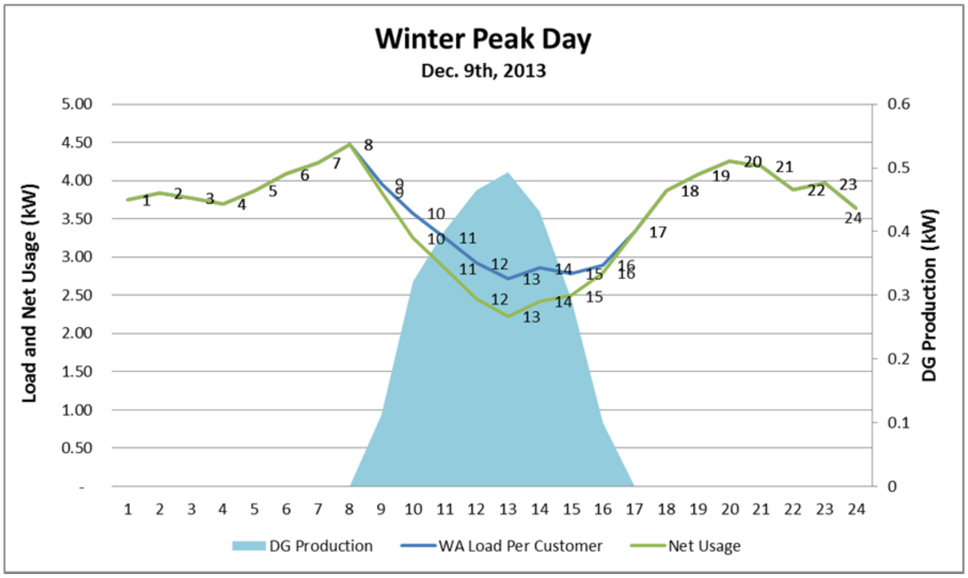
[32] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 37:1-5.

partial requirements customer class would be redesigned and developed consistent with the costs of serving customers: demand-related costs would be recovered through demand charges, customer-related costs through customer charges, and energy-related costs through energy charges. This type of rate design is already used extensively in all nonresidential rate schedules so should therefore not be novel to Staff.

Third, Staff imputes to the Company an argument on the rationale for a future rate that the Company did not make when it points to "The Duck Curve" and then argues that the three-part rate design would not reflect the operations of Pacific Power's west control area system.[33] Again, the Company is collecting data to inform the discussion and is not proposing a rate based on studies in other jurisdictions. Additionally, Staff apparently fails to understand that with a three-part rate that includes a peak-based demand charge, to the extent a DG customer reduces load during the peak, the customer will receive the benefit of those cost-based savings by avoiding peak charges.

Fourth, Staff's analysis vastly over-simplifies cost drivers by concluding that DG customers help meet peak load because the peak occurs during daylight hours, which is when DG is producing. The peak occurs in an hour, not merely in the broader period of daylight. And in the west control area, the peak occurs in winter, which is when output from solar DG is significantly less. In fact, the graph below shows the peak winter day during the test period for the residential average load profile, assumed DG production and net usage.

[33] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 37-40.



The winter peak day shows a few important things. First, during the peak hour of 8:00 am, DG production is not yet producing so it is not helping the Company meet load. Second, the west control area typically produces two peaks in a day, one in the morning and one in the evening. This same day also had the highest ranked evening peak of the year at the hour of 7:00 pm. DG production during this hour was also zero and thus not contributing energy to meet load. Lastly, the blue area of the chart is the assumed DG production. This is based off of an assumed 4 kW system in Yakima using the PVWatts Solar calculator. The chart clearly shows that solar DG production does not align with the morning or evening peaks. My point in providing this graph is that, again, actual data will help inform the discussion and therefore, Staff's rush to judgment should be dismissed.

Lastly, Staff states several times that its proposed rate spread will address many of the issues associated with DG. Rate spread is an allocation of revenues to a class. DG issues, on the other hand, are a rate design issue so I fail to see how Staff's rate spread has any relationship to DG.

GENERAL SERVICE, AGRICULTURAL PUMPING, AND STREET LIGHTING RATE DESIGN

Q. Is the Company proposing any changes in this rebuttal filing to rate designs for the general service, agricultural pumping, and street lighting schedules?

A. The Company is proposing one change to rate design for general service Schedule 36, in response to Wal-Mart's testimony. Staff proposed for those classes receiving an increase to allocate the increase evenly across the usage-based rates within the class, except for the basic charge for the Dedicated Facilities class. The Company is proposing no change from the approach in its original filed case which allocated more of the increase to demand to move cost components closer to cost of service.

Q. Please explain the rate design changes for Schedule 36 proposed by Wal-Mart.

A. Wal-Mart proposed an unbundled generation demand rate equal to 50 percent of a generation demand rate calculated by dividing generation demand costs by the Schedule 36 NCP kW found in the "Unit Costs" tab of Exhibit No. JRS-15. Likewise a proposed unbundled transmission demand rate equal to 50 percent of a transmission demand rate calculated by dividing transmission demand costs by the Schedule 36 NCP kW.

Q. What is the Company's response to Wal-Mart's proposal?

A. The Company agrees in part with Wal-Mart's proposed rate design, however, the Company is proposing a more gradual movement in increasing the demand charge for Schedule 36 in light of bill impacts. Specifically, the Company proposes a movement that is half way between a rebuttal rate calculated the same as the original filing of $3.49 or approximately 40 percent of total generation demand and Wal-Mart's 50 percent generation demand proposal or $4.38. The proposed rate of $3.94 is approximately 45 percent of total generation demand costs. The transmission demand rate is calculated using the same approach as applied above but for transmission demand.

RULE D AND SCHEDULE 300

Q. The Company proposed changes to Rule D and Schedule 300 in the direct testimony of Company witness Ms. Barbara A. Coughlin. Does the Company continue to support the tariff revisions proposed in Ms. Coughlin's testimony?

A. Not entirely. In response to concerns raised by the parties, the Company is willing to withdraw its proposal for the Collection Agency to charge the customer as reflected in the changes proposed for Rule 11D, its proposal for changes to the Field Visit Charge language in Rule 11D, and its proposal to increase the Connection Charge and Reconnection Charge. In doing so, an adjustment of $83,324 to increase revenue requirement is being made.

Q. Why is the Company withdrawing these proposed tariff revisions?

A. In the Company's last rate case it presented a similar proposal to increase the Connection and Reconnection Charges. Parties in that case were concerned that the Company's proposal to increase the Connection and Reconnection Charges was based on estimates from a study rather than the actual cost of the work performed. The Company voluntarily withdrew its tariff filing to gather actual data and undertake additional analysis to demonstrate the validity of actual costs. At that time the Company committed to bring forward Connection and Reconnection Charges based on actual data and analysis, which has been done in this case. However, parties again expressed concern over the magnitude of the proposed increase based on the Company's actual data. Therefore, the Company is willing to withdraw the proposal.

Q. There are other tariff changes proposed in Ms. Coughlin's direct testimony that have not been discussed in this rebuttal testimony. Did parties raise concerns in testimony for (1) implementation of a non-radio frequency meter charge (Rule 8 and Schedule 300); (2) increasing the Unauthorized Reconnection/Tampering Charge (Schedule 300); (3) modification of the Facilities Charge (Schedule 300); or (4) modification of the title of Returned Check Charge (Schedule 300)?

A. No. The Parties did not object to any of the Company's other proposed changes and the Company continues to support these proposed changes.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit No. JRS-14
Docket UE-140762 *et al.*
Witness: Joelle R. Steward

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF JOELLE R. STEWARD

Cost of Service by Rate Schedule - Summaries

November 2014

Summary

PacifiCorp
Cost Of Service By Rate Schedule
State of Washington
12 Months Ending December 2013
WCA Method - (100 Summer, 100 Winter Hours) - 43%D / 57%E
5.41% = Earned Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	16	Residential	140,088,119	3.22%	0.59	148,770,675	90,417,148	21,818,121	28,207,303	5,811,723	2,516,381	8,682,557	6.20%
2	24	Small General Service	48,473,096	9.85%	1.82	43,364,247	28,266,211	6,812,815	6,671,406	778,998	834,817	(5,108,850)	-10.54%
3	36	Large General Service <1,000 kW	66,810,176	7.15%	1.32	63,918,188	45,059,511	10,888,589	6,708,795	8,192	1,253,102	(2,891,988)	-4.33%
4	48T	Large General Service >1,000 kW	26,035,610	6.18%	1.14	25,531,440	18,382,172	4,440,916	2,178,781	29,089	500,482	(504,171)	-1.94%
5	48T	Dedicated Facilities	24,940,664	3.60%	0.67	26,083,308	20,237,044	4,884,982	427,883	14,813	518,585	1,142,643	4.58%
6	40	Agricultural Pumping Service	12,666,289	9.01%	1.66	11,524,580	7,418,704	1,783,284	1,966,846	135,598	220,147	(1,141,709)	-9.01%
7	15,52,54,57	Street Lighting	1,648,057	9.82%	1.81	1,469,574	496,824	119,687	735,378	97,361	20,324	(178,482)	-10.83%
8		Total Washington Jurisdiction	320,662,012	5.41%	1.00	320,662,012	210,277,615	50,748,394	46,896,391	6,875,775	5,863,837	(0)	0.00%

Footnotes :

Column C : Annual revenues based on January 2013 through December 2013 usage priced at current Washington Tariff.
Column D : Calculated Return on Ratebase per January 2013 through December 2013 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Washington Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per the January 2013 through December 2013 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per January 2013 through December 2013 Embedded COS Study.
Column H : Calculated Transmission Cost of Service at Jurisdictional Rate of Return per January 2013 through December 2013 Embedded COS Study.
Column I : Calculated Distribution Cost of Service at Jurisdictional Rate of Return per the January 2013 through December 2013 Embedded COS Study.
Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per the January 2013 through December 2013 Embedded COS Study.
Column K : Calculated Miscellaneous Cost of Service at Jurisdictional Rate of Return per the January 2013 through December 2013 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service percent.

PacifiCorp
Cost Of Service By Rate Schedule
State of Washington
12 Months Ending December 2013
WCA Method - (100 Summer, 100 Winter Hours) - 43%D / 57%E
7.76% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	16	Residential	140,088,119	3.22%	0.59	163,792,081	98,351,484	24,283,866	32,853,370	5,749,833	2,553,529	23,703,963	16.92%
2	24	Small General Service	48,473,096	9.85%	1.82	47,734,808	30,746,707	7,578,072	7,789,821	773,584	846,625	(738,288)	-1.52%
3	36	Large General Service <1,000 kW	66,810,176	7.15%	1.32	70,232,276	49,015,377	12,119,267	7,826,236	(113)	1,271,510	3,422,100	5.12%
4	48T	Large General Service >1,000 kW	26,035,610	6.18%	1.14	28,011,710	19,996,257	4,943,112	2,535,201	29,198	507,942	1,976,100	7.59%
5	48T	Dedicated Facilities	24,940,664	3.60%	0.67	28,476,719	22,014,968	5,438,249	482,059	14,793	526,650	3,536,055	14.18%
6	40	Agricultural Pumping Service	12,666,289	9.01%	1.66	12,730,015	8,069,740	1,982,127	2,322,143	132,753	223,252	63,726	0.50%
7	15,52,54,57	Street Lighting	1,648,057	9.82%	1.81	1,623,358	540,259	133,075	831,391	98,071	20,562	(24,698)	-1.50%
8		Total Washington Jurisdiction	320,662,012	5.41%	1.00	352,600,969	228,734,791	56,477,767	54,640,221	6,798,118	5,950,071	31,938,957	9.96%

Footnotes :

Column C : Annual revenues based on January 2013 through December 2013 usage priced at current Washington Tariff.
Column D : Calculated Return on Ratebase per January 2013 through December 2013 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Washington Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per the January 2013 through December 2013 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per January 2013 through December 2013 Embedded COS Study.
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Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per the January 2013 through December 2013 Embedded COS Study.
Column K : Calculated Miscellaneous Cost of Service at Jurisdictional Rate of Return per the January 2013 through December 2013 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service percent.

Exhibit No. JRS-15
Docket UE-140762 *et al.*
Witness: Joelle R. Steward

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF JOELLE R. STEWARD

Cost of Service by Rate Schedule – All Functions

November 2014

Class Summary

PacifiCorp
Cost Of Service By Rate Schedule - All Functions
State of Washington
WCA Method - (100 Summer, 100 Winter Hours) - 43%D / 57%E
12 Months Ending December 2013

A DESCRIPTION	B	C Washington Jurisdiction Normalized	D Residential Schedule 16	F Small General Service Schedule 24	G Large General Service <1,000 kW Schedule 36	H Large General Service >1,000 kW Schedule 48T	I Large General Dedicated Facilities Schedule 48T	J Agricultural Pumping Schedule 40	K Street & Area Lighting Sch. 15,51-54,57
Operating Revenues		351,177,814	153,380,507	52,608,115	73,229,166	28,583,724	27,672,507	13,967,333	1,736,462
Operating Expenses									
Operation & Maintenance Expenses		229,071,730	103,748,212	30,747,378	46,587,127	18,812,469	20,120,333	8,161,558	894,653
Depreciation Expense		44,704,303	21,521,406	6,134,977	8,626,488	3,348,768	3,081,043	1,726,772	264,849
Amortization Expense		5,116,519	2,363,907	691,598	1,015,211	409,223	434,499	181,241	20,840
Taxes Other Than Income		21,000,296	10,039,048	2,866,763	4,093,334	1,591,718	1,506,547	798,249	104,637
Income Taxes - Federal		628,606	884,295	152,782	(134,694)	(95,219)	(297,252)	69,012	49,682
Income Taxes - State		-	-	-	-	-	-	-	-
Income Taxes Deferred		5,851,134	2,400,735	773,145	1,305,504	540,953	629,064	196,015	5,718
Investment Tax Credit Adj		-	-	-	-	-	-	-	-
Misc Revenues & Expense		(762,127)	(325,600)	(102,865)	(164,110)	(66,963)	(73,766)	(27,020)	(1,803)
Total Operating Expenses		305,610,461	140,632,003	41,263,779	61,328,860	24,540,948	25,400,468	11,105,828	1,338,575
Operating Revenue For Return		45,567,353	12,748,504	11,344,335	11,900,307	4,042,775	2,272,039	2,861,506	397,886
Rate Base :									
Electric Plant In Service		1,751,865,644	838,628,075	240,039,706	340,233,143	132,535,348	123,853,540	67,222,529	9,353,302
Plant Held For Future Use		234,062	100,615	31,456	50,168	20,470	22,547	8,256	551
Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-
Nuclear Fuel		-	-	-	-	-	-	-	-
Prepayments		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Fuel Stock		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Materials & Supplies		0	0	0	0	0	0	0	0
Misc Deferred Debits		8,025,149	3,449,733	1,078,506	1,720,074	701,827	773,053	283,077	18,879
Cash Working Capital		31,018,483	14,152,613	4,172,836	6,264,712	2,516,365	2,652,784	1,120,157	139,017
Weatherization Loans		1,932,316	830,636	259,685	414,164	168,988	186,138	68,160	4,546
Miscellaneous Rate Base		-	-	-	-	-	-	-	-
Total Rate Base Additions		1,793,075,655	857,161,672	245,582,188	348,682,260	135,942,998	127,488,062	68,702,180	9,516,295
Rate Base Deductions :									
Accum Provision For Depreciation		(649,561,462)	(314,918,004)	(89,048,063)	(125,042,327)	(48,240,393)	(42,918,723)	(25,511,537)	(3,882,414)
Accum Provision For Amortization		(47,738,217)	(24,418,129)	(6,491,151)	(8,249,637)	(3,274,870)	(3,323,908)	(1,664,517)	(316,006)
Accum Deferred Income Taxes		(246,661,552)	(117,610,659)	(33,825,511)	(48,005,161)	(18,756,011)	(17,835,214)	(9,378,992)	(1,250,003)
Unamortized ITC		(246,775)	(118,011)	(33,896)	(47,965)	(18,670)	(17,494)	(9,463)	(1,276)
Customer Advance For Construction		(488,824)	(70,339)	(261,146)	(2,402)	-	-	(151,101)	(3,837)
Customer Service Deposits		(3,361,134)	(2,732,690)	(297,257)	(227,064)	-	-	(102,064)	(2,059)
Misc Rate Base Deductions		(3,253,188)	(1,398,432)	(437,198)	(697,273)	(284,503)	(313,376)	(114,752)	(7,653)
Total Rate Base Deductions		(951,311,153)	(461,266,265)	(130,394,222)	(182,271,829)	(70,574,446)	(64,408,715)	(36,932,426)	(5,463,248)
Total Rate Base		841,764,502	395,895,407	115,187,966	166,410,431	65,368,552	63,079,346	31,769,753	4,053,047
Calculated Return On Rate Base		5.41%	3.22%	9.85%	7.15%	6.18%	3.60%	9.01%	9.82%
Return On Rate Base @ Jurisdictional Ave.	5.41%	45,567,353	21,431,060	6,235,486	9,008,319	3,538,605	3,414,683	1,719,796	219,404
Total Operating Expenses		305,610,461	140,632,003	41,263,779	61,328,860	24,540,948	25,400,468	11,105,828	1,338,575
Revenue Credits		(30,515,802)	(13,292,388)	(4,135,018)	(6,418,990)	(2,548,113)	(2,731,843)	(1,301,044)	(88,405)
Total Revenue Requirements		320,662,012	148,770,675	43,364,247	63,918,188	25,531,440	26,083,308	11,524,580	1,469,574
Class Revenue		320,662,012	140,088,119	48,473,096	66,810,176	26,035,610	24,940,664	12,666,289	1,648,057
Increase / (Decrease) Required to Earn Equal Rates of Return		0	8,682,557	(5,108,850)	(2,891,988)	(504,171)	1,142,643	(1,141,709)	(178,482)
Percent %		0.00%	6.20%	-10.54%	-4.33%	-1.94%	4.58%	-9.01%	-10.83%
Return On Rate Base @ Target ROR	7.76%	65,350,343	30,735,319	8,942,612	12,919,265	5,074,884	4,897,162	2,466,443	314,658
Total Operating Expenses Adjusted for Taxes		317,766,428	146,349,150	42,927,215	63,732,002	25,484,939	26,311,400	11,564,616	1,397,106
Revenue Credits		(30,515,802)	(13,292,388)	(4,135,018)	(6,418,990)	(2,548,113)	(2,731,843)	(1,301,044)	(88,405)
Total Target Revenue Requirements		352,600,969	163,792,081	47,734,808	70,232,276	28,011,710	28,476,719	12,730,015	1,623,358
Class Revenue		320,662,012	140,088,119	48,473,096	66,810,176	26,035,610	24,940,664	12,666,289	1,648,057
Increase / (Decrease) Required to Earn Target Rate of Return		31,938,957	23,703,963	(738,288)	3,422,100	1,976,100	3,536,055	63,726	(24,698)
Percent %		9.96%	16.92%	-1.52%	5.12%	7.59%	14.18%	0.50%	-1.50%

Generation Summary

PacifiCorp
Cost Of Service By Rate Schedule - Generation Function
State of Washington
WCA Method - (100 Summer, 100 Winter Hours) - 43%D / 57%E
12 Months Ending December 2013

	A	B	C	D	E	F	G	H	I	J
	DESCRIPTION		Washington Jurisdiction Normalized	Residential Schedule 16	Small General Service Schedule 24	Large General Service <1,000 kW Schedule 36	Large General Service >1,000 kW Schedule 48T	Large General Dedicated Facilities Schedule 48T	Agricultural Pumping Schedule 40	Street & Area Lighting Sch. 15,51-54,57
14	Operating Expenses									
15	Operation & Maintenance Expenses		171,069,784	73,600,630	22,997,751	36,633,783	14,944,109	16,450,501	6,036,281	406,729
16	Depreciation Expense		25,383,484	10,911,478	3,411,305	5,440,580	2,219,874	2,445,162	895,370	59,715
17	Amortization Expense		3,742,810	1,615,934	503,146	798,672	325,695	358,178	132,010	9,175
18	Taxes Other Than Income		10,565,977	4,542,082	1,419,982	2,264,571	923,998	1,017,788	372,691	24,864
19	Income Taxes - Federal		(1,978,842)	(850,661)	(265,940)	(424,119)	(173,050)	(190,616)	(69,799)	(4,657)
20	Income Taxes - State		-	-	-	-	-	-	-	-
21	Income Taxes Deferred		2,364,526	1,016,458	317,773	506,781	206,778	227,768	83,403	5,564
22	Investment Tax Credit Adj		-	-	-	-	-	-	-	-
23	Misc Revenues & Expense		(780,928)	(335,694)	(104,949)	(167,380)	(68,295)	(75,226)	(27,546)	(1,837)
24										
25	Total Operating Expenses		210,366,811	90,500,227	28,279,068	45,052,888	18,379,109	20,233,555	7,422,410	499,554
26										
27										
28	Rate Base :									
29	Electric Plant In Service		921,880,249	396,284,279	123,892,166	197,591,593	80,621,651	88,803,653	32,518,164	2,168,744
30	Plant Held For Future Use		234,062	100,615	31,456	50,168	20,470	22,547	8,256	551
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-
33	Prepayments		(0)	(0)	(0)	(0)	(0)	(0)	(0)	0
34	Fuel Stock		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
35	Materials & Supplies		0	0	0	0	0	0	0	0
36	Misc Deferred Debits		8,005,060	3,441,097	1,075,806	1,715,768	700,071	771,118	282,368	18,832
37	Cash Working Capital		22,228,445	9,563,510	2,988,279	4,760,116	1,941,806	2,137,543	784,342	52,849
38	Weatherization Loans		-	-	-	-	-	-	-	-
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-
40										
41	Total Rate Base Additions		952,347,816	409,389,501	127,987,706	204,117,645	83,283,996	91,734,861	33,593,130	2,240,976
42										
43	Rate Base Deductions :									
44	Accum Provision For Depreciation		(309,337,845)	(132,973,588)	(41,572,141)	(66,302,058)	(27,052,676)	(29,798,155)	(10,911,503)	(727,724)
45	Accum Provision For Amortization		(26,607,545)	(11,448,848)	(3,576,388)	(5,698,268)	(2,324,226)	(2,557,327)	(939,214)	(63,273)
46	Accum Deferred Income Taxes		(127,316,605)	(54,719,826)	(17,110,000)	(27,293,133)	(11,136,395)	(12,267,224)	(4,490,990)	(299,038)
47	Unamortized ITC		(127,556)	(54,830)	(17,142)	(27,341)	(11,156)	(12,289)	(4,499)	(300)
48	Customer Advance For Construction		-	-	-	-	-	-	-	-
49	Customer Service Deposits		-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		(2,511,720)	(1,079,701)	(337,552)	(538,351)	(219,659)	(241,951)	(88,598)	(5,909)
51										
52	Total Rate Base Deductions		(465,901,271)	(200,276,793)	(62,613,223)	(99,859,150)	(40,744,112)	(44,876,945)	(16,434,803)	(1,096,245)
53										
54	Total Rate Base		486,446,545	209,112,708	65,374,483	104,258,495	42,539,884	46,857,916	17,158,327	1,144,732
55										
56										
57	Return On Rate Base	5.41%	26,332,877	11,319,927	3,538,926	5,643,839	2,302,817	2,536,566	928,834	61,968
58	Total Operating Expenses		210,366,811	90,500,227	28,279,068	45,052,888	18,379,109	20,233,555	7,422,410	499,554
59	Revenue Credits		(26,422,074)	(11,403,006)	(3,551,782)	(5,637,216)	(2,299,754)	(2,533,077)	(932,540)	(64,698)
60										
61	Total Revenue Requirements		210,277,615	90,417,148	28,266,211	45,059,511	18,382,172	20,237,044	7,418,704	496,824
62										
63										
64	Return On Rate Base @ Target ROR	7.76%	37,765,252	16,234,454	5,075,345	8,094,103	3,302,582	3,637,812	1,332,086	88,871
65	Total Operating Expenses Adjusted for Taxes		217,391,612	93,520,036	29,223,144	46,558,490	18,993,429	20,910,233	7,670,195	516,085
66	Revenue Credits		(26,422,074)	(11,403,006)	(3,551,782)	(5,637,216)	(2,299,754)	(2,533,077)	(932,540)	(64,698)
67										
68	Total Target Revenue Requirements		228,734,791	98,351,484	30,746,707	49,015,377	19,996,257	22,014,968	8,069,740	540,259

Generation Demand Summary

Transmission Summary

PacifiCorp
Cost Of Service By Rate Schedule - Transmission Function
State of Washington
WCA Method - (100 Summer, 100 Winter Hours) - 43%D / 57%E
12 Months Ending December 2013

	A	B	C	D	E	F	G	H	I	J
	DESCRIPTION		Washington Jurisdiction Normalized	Residential Schedule 16	Small General Service Schedule 24	Large General Service <1,000 kW Schedule 36	Large General Service >1,000 kW Schedule 48T	Large General Dedicated Facilities Schedule 48T	Agricultural Pumping Schedule 40	Street & Area Lighting Sch. 15,51-54,57
14	Operating Expenses									
15	Operation & Maintenance Expenses		32,904,019	14,159,457	4,427,955	7,045,173	2,872,420	3,156,986	1,162,953	79,075
16	Depreciation Expense		5,888,767	2,531,376	791,396	1,262,171	514,993	567,258	207,719	13,853
17	Amortization Expense		729,561	313,613	98,046	156,371	63,803	70,278	25,734	1,716
18	Taxes Other Than Income		4,651,450	2,001,840	621,281	999,139	407,713	449,175	161,432	10,869
19	Income Taxes - Federal		(1,407,496)	(605,743)	(187,995)	(302,332)	(123,371)	(135,917)	(48,848)	(3,289)
20	Income Taxes - State		-	-	-	-	-	-	-	-
21	Income Taxes Deferred		4,210,373	1,812,014	562,368	904,395	369,051	406,582	146,124	9,838
22	Investment Tax Credit Adj		-	-	-	-	-	-	-	-
23	Misc Revenues & Expense		14,631	6,290	1,966	3,136	1,280	1,409	516	34
24										
25	Total Operating Expenses		46,991,305	20,218,847	6,315,017	10,068,052	4,105,889	4,515,771	1,655,630	112,098
26										
27										
28	Rate Base :									
29	Electric Plant In Service		331,835,586	142,644,586	44,595,629	71,124,121	29,020,182	31,965,336	11,705,082	780,651
30	Plant Held For Future Use		-	-	-	-	-	-	-	-
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-
33	Prepayments		(0)	(0)	(0)	(0)	(0)	(0)	(0)	0
34	Fuel Stock		-	-	-	-	-	-	-	-
35	Materials & Supplies		0	0	0	0	0	0	0	0
36	Misc Deferred Debits		20,089	8,636	2,700	4,306	1,757	1,935	709	47
37	Cash Working Capital		4,472,487	1,924,628	601,871	957,617	390,434	429,114	158,075	10,748
38	Weatherization Loans		-	-	-	-	-	-	-	-
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-
40										
41	Total Rate Base Additions		336,328,162	144,577,849	45,200,199	72,086,043	29,412,373	32,396,386	11,863,865	791,446
42										
43	Rate Base Deductions :									
44	Accum Provision For Depreciation		(124,684,934)	(53,597,720)	(16,756,500)	(26,724,398)	(10,904,133)	(12,010,755)	(4,398,104)	(293,324)
45	Accum Provision For Amortization		(6,756,361)	(2,924,673)	(909,048)	(1,439,633)	(585,964)	(640,381)	(239,534)	(17,129)
46	Accum Deferred Income Taxes		(53,196,352)	(22,861,862)	(7,148,817)	(11,404,118)	(4,653,509)	(5,127,117)	(1,876,112)	(124,818)
47	Unamortized ITC		(48,902)	(21,016)	(6,572)	(10,484)	(4,278)	(4,713)	(1,725)	(115)
48	Customer Advance For Construction		(311,073)	(44,762)	(166,185)	(1,528)	-	-	(96,156)	(2,442)
49	Customer Service Deposits		-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		(330,534)	(142,085)	(44,421)	(70,845)	(28,906)	(31,840)	(11,659)	(778)
51										
52	Total Rate Base Deductions		(185,328,157)	(79,592,118)	(25,031,543)	(39,651,005)	(16,176,790)	(17,814,806)	(6,623,290)	(438,605)
53										
54	Total Rate Base		151,000,005	64,985,731	20,168,657	32,435,038	13,235,583	14,581,580	5,240,575	352,841
55										
56										
57	Return On Rate Base	5.41%	8,174,104	3,517,881	1,091,793	1,755,810	716,484	789,347	283,689	19,100
58	Total Operating Expenses		46,991,305	20,218,847	6,315,017	10,068,052	4,105,889	4,515,771	1,655,630	112,098
59	Revenue Credits		(4,417,015)	(1,918,608)	(593,995)	(935,274)	(381,456)	(420,136)	(156,035)	(11,511)
60										
61	Total Revenue Requirements		50,748,394	21,818,121	6,812,815	10,888,589	4,440,916	4,884,982	1,783,284	119,687
62										
63										
64	Return On Rate Base @ Target ROR	7.76%	11,722,877	5,045,164	1,565,793	2,518,092	1,027,544	1,132,040	406,852	27,393
65	Total Operating Expenses Adjusted for Taxes		49,171,904	21,157,310	6,606,274	10,536,449	4,297,025	4,726,344	1,731,310	117,193
66	Revenue Credits		(4,417,015)	(1,918,608)	(593,995)	(935,274)	(381,456)	(420,136)	(156,035)	(11,511)
67										
68	Total Target Revenue Requirements		56,477,767	24,283,866	7,578,072	12,119,267	4,943,112	5,438,249	1,982,127	133,075
	Transmission Demand Summary									

Distribution Summary

PacifiCorp
Cost Of Service By Rate Schedule - Distribution Function
State of Washington
WCA Method - (100 Summer, 100 Winter Hours) - 43%D / 57%E
12 Months Ending December 2013

	A	B	C	D	E	F	G	H	I	J
	DESCRIPTION		Washington Jurisdiction Normalized	Residential Schedule 16	Small General Service Schedule 24	Large General Service <1,000 kW Schedule 36	Large General Service >1,000 kW Schedule 48T	Large General Dedicated Facilities Schedule 48T	Agricultural Pumping Schedule 40	Street & Area Lighting Sch. 15,51-54,57
14	Operating Expenses									
15	Operation & Maintenance Expenses		14,595,968	8,348,801	2,056,878	2,208,615	719,458	269,236	696,863	296,117
16	Depreciation Expense		13,337,215	8,001,944	1,919,287	1,922,907	613,744	68,621	621,412	189,300
17	Amortization Expense		376,148	217,874	53,699	57,823	19,284	6,036	17,079	4,352
18	Taxes Other Than Income		5,653,031	3,391,650	816,448	815,737	260,189	39,549	259,369	70,090
19	Income Taxes - Federal		4,387,046	2,632,096	633,606	633,054	201,920	30,692	201,283	54,394
20	Income Taxes - State		-	-	-	-	-	-	-	-
21	Income Taxes Deferred		(756,759)	(454,033)	(109,296)	(109,201)	(34,831)	(5,294)	(34,721)	(9,383)
22	Investment Tax Credit Adj		-	-	-	-	-	-	-	-
23	Misc Revenues & Expense		0	0	0	0	0	0	0	0
24										
25	Total Operating Expenses		37,592,648	22,138,333	5,370,622	5,528,935	1,779,763	408,839	1,761,285	604,870
26										
27										
28	Rate Base :									
29	Electric Plant In Service		487,956,677	291,465,388	70,155,814	71,428,209	22,876,706	3,084,275	22,755,205	6,191,078
30	Plant Held For Future Use		-	-	-	-	-	-	-	-
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-
33	Prepayments		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
34	Fuel Stock		-	-	-	-	-	-	-	-
35	Materials & Supplies		0	0	0	0	0	0	0	0
36	Misc Deferred Debits		0	0	0	0	0	0	0	0
37	Cash Working Capital		3,048,148	1,743,522	429,548	461,236	150,248	56,226	145,529	61,840
38	Weatherization Loans		-	-	-	-	-	-	-	-
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-
40										
41	Total Rate Base Additions		491,004,825	293,208,910	70,585,362	71,889,445	23,026,954	3,140,501	22,900,735	6,252,918
42										
43	Rate Base Deductions :									
44	Accum Provision For Depreciation		(215,089,275)	(127,983,672)	(30,657,869)	(32,011,938)	(10,282,842)	(1,109,801)	(10,191,170)	(2,851,982)
45	Accum Provision For Amortization		(6,514,853)	(3,763,237)	(929,283)	(1,005,113)	(336,558)	(111,259)	(294,710)	(74,694)
46	Accum Deferred Income Taxes		(64,659,048)	(38,772,548)	(9,362,782)	(9,324,653)	(2,975,576)	(452,425)	(2,978,496)	(792,569)
47	Unamortized ITC		(70,317)	(42,165)	(10,182)	(10,140)	(3,236)	(492)	(3,239)	(862)
48	Customer Advance For Construction		(177,752)	(25,577)	(94,961)	(873)	-	-	(54,945)	(1,395)
49	Customer Service Deposits		-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		(401,707)	(172,680)	(53,986)	(86,100)	(35,131)	(38,696)	(14,170)	(945)
51										
52	Total Rate Base Deductions		(286,912,951)	(170,759,880)	(41,109,063)	(42,438,818)	(13,633,343)	(1,712,673)	(13,536,729)	(3,722,446)
53										
54	Total Rate Base		204,091,874	122,449,030	29,476,299	29,450,627	9,393,612	1,427,829	9,364,006	2,530,472
55										
56										
57	Return On Rate Base	5.41%	11,048,133	6,628,550	1,595,645	1,594,255	508,506	77,293	506,903	136,982
58	Total Operating Expenses		37,592,648	22,138,333	5,370,622	5,528,935	1,779,763	408,839	1,761,285	604,870
59	Revenue Credits		(1,744,391)	(559,580)	(294,861)	(414,395)	(109,488)	(58,249)	(301,342)	(6,475)
60										
61	Total Revenue Requirements		46,896,391	28,207,303	6,671,406	6,708,795	2,178,781	427,883	1,966,846	735,378
62										
63										
64	Return On Rate Base @ Target ROR	7.76%	15,844,662	9,506,324	2,288,391	2,286,398	729,273	110,849	726,974	196,453
65	Total Operating Expenses Adjusted for Taxes		40,539,950	23,906,626	5,796,291	5,954,233	1,915,417	429,459	1,896,511	641,413
66	Revenue Credits		(1,744,391)	(559,580)	(294,861)	(414,395)	(109,488)	(58,249)	(301,342)	(6,475)
67										
68	Total Target Revenue Requirements		54,640,221	32,853,370	7,789,821	7,826,236	2,535,201	482,059	2,322,143	831,391

Retail Summary

PacifiCorp
Cost Of Service By Rate Schedule - Retail Services Function
State of Washington
WCA Method - (100 Summer, 100 Winter Hours) - 43%D / 57%E
12 Months Ending December 2013

	A	B	C	D	E	F	G	H	I	J
	DESCRIPTION		Washington Jurisdiction Normalized	Residential Schedule 16	Small General Service Schedule 24	Large General Service <1,000 kW Schedule 36	Large General Service >1,000 kW Schedule 48T	Large General Dedicated Facilities Schedule 48T	Agricultural Pumping Schedule 40	Street & Area Lighting Sch. 15,51-54,57
14	Operating Expenses									
15	Operation & Maintenance Expenses		7,736,448	6,433,594	846,178	122,727	52,044	28,949	154,420	98,537
16	Depreciation Expense		94,837	76,607	12,989	830	156	3	2,271	1,980
17	Amortization Expense		268,000	216,486	36,707	2,346	442	7	6,417	5,596
18	Taxes Other Than Income		129,839	103,477	9,052	13,887	(181)	34	4,757	(1,187)
19	Income Taxes - Federal		(358,026)	(285,334)	(24,961)	(38,292)	500	(95)	(13,117)	3,273
20	Income Taxes - State		-	-	-	-	-	-	-	-
21	Income Taxes Deferred		32,994	26,295	2,300	3,529	(46)	9	1,209	(302)
22	Investment Tax Credit Adj		-	-	-	-	-	-	-	-
23	Misc Revenues & Expense		4,169	3,804	118	134	52	50	10	-
24										
25	Total Operating Expenses		7,908,261	6,574,929	882,383	105,160	52,967	28,957	155,967	107,897
26										
27										
28	Rate Base :									
29	Electric Plant In Service		10,193,132	8,233,822	1,396,097	89,221	16,809	276	244,079	212,829
30	Plant Held For Future Use		-	-	-	-	-	-	-	-
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-
33	Prepayments		0	0	0	0	0	0	0	0
34	Fuel Stock		-	-	-	-	-	-	-	-
35	Materials & Supplies		-	-	-	-	-	-	-	-
36	Misc Deferred Debits		0	0	0	0	0	0	0	0
37	Cash Working Capital		928,976	772,532	101,607	14,737	6,249	3,476	18,542	11,832
38	Weatherization Loans		-	-	-	-	-	-	-	-
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-
40										
41	Total Rate Base Additions		11,122,108	9,006,354	1,497,704	103,958	23,059	3,752	262,621	224,661
42										
43	Rate Base Deductions :									
44	Accum Provision For Depreciation		(449,408)	(363,024)	(61,553)	(3,934)	(741)	(12)	(10,761)	(9,383)
45	Accum Provision For Amortization		(7,859,458)	(6,281,370)	(1,076,432)	(106,623)	(28,122)	(14,942)	(191,059)	(160,910)
46	Accum Deferred Income Taxes		(1,489,547)	(1,256,424)	(203,912)	16,742	9,468	11,551	(33,394)	(33,579)
47	Unamortized ITC		-	-	-	-	-	-	-	-
48	Customer Advance For Construction		0	0	0	0	-	-	0	0
49	Customer Service Deposits		(3,361,134)	(2,732,690)	(297,257)	(227,064)	-	-	(102,064)	(2,059)
50	Misc Rate Base Deductions		(9,226)	(3,966)	(1,240)	(1,978)	(807)	(889)	(325)	(22)
51										
52	Total Rate Base Deductions		(13,168,774)	(10,637,474)	(1,640,393)	(322,856)	(20,202)	(4,292)	(337,604)	(205,953)
53										
54	Total Rate Base		(2,046,666)	(1,631,120)	(142,689)	(218,899)	2,857	(540)	(74,983)	18,708
55										
56										
57	Return On Rate Base	5.41%	(110,792)	(88,298)	(7,724)	(11,850)	155	(29)	(4,059)	1,013
58	Total Operating Expenses		7,908,261	6,574,929	882,383	105,160	52,967	28,957	155,967	107,897
59	Revenue Credits		(921,694)	(674,908)	(95,661)	(85,118)	(24,033)	(14,115)	(16,310)	(11,548)
60										
61	Total Revenue Requirements		6,875,775	5,811,723	778,998	8,192	29,089	14,813	135,598	97,361
62										
63										
64	Return On Rate Base @ Target ROR	7.76%	(158,893)	(126,632)	(11,078)	(16,994)	222	(42)	(5,821)	1,452
65	Total Operating Expenses Adjusted for Taxes		7,878,705	6,551,373	880,323	101,999	53,009	28,950	154,884	108,167
66	Revenue Credits		(921,694)	(674,908)	(95,661)	(85,118)	(24,033)	(14,115)	(16,310)	(11,548)
67										
68	Total Target Revenue Requirements		6,798,118	5,749,833	773,584	(113)	29,198	14,793	132,753	98,071

MISC Summary

PacifiCorp
Cost Of Service By Rate Schedule - Miscellaneous Function
State of Washington
WCA Method - (100 Summer, 100 Winter Hours) - 43%D / 57%E
12 Months Ending December 2013

	A	B	C	D	E	F	G	H	I	J
	DESCRIPTION		Washington Jurisdiction Normalized	Residential Schedule 16	Small General Service Schedule 24	Large General Service <1,000 kW Schedule 36	Large General Service >1,000 kW Schedule 48T	Large General Dedicated Facilities Schedule 48T	Agricultural Pumping Schedule 40	Street & Area Lighting Sch. 15,51-54,57
14	Operating Expenses									
15	Operation & Maintenance Expenses		2,765,511	1,205,730	418,615	576,829	224,438	214,662	111,042	14,195
16	Depreciation Expense		-	-	-	-	-	-	-	-
17	Amortization Expense		-	-	-	-	-	-	-	-
18	Taxes Other Than Income		-	-	-	-	-	-	-	-
19	Income Taxes - Federal		(14,075)	(6,063)	(1,927)	(3,005)	(1,218)	(1,316)	(507)	(39)
20	Income Taxes - State		-	-	-	-	-	-	-	-
21	Income Taxes Deferred		-	-	-	-	-	-	-	-
22	Investment Tax Credit Adj		-	-	-	-	-	-	-	-
23	Misc Revenues & Expense		-	-	-	-	-	-	-	-
24										
25	Total Operating Expenses		2,751,436	1,199,667	416,688	573,824	223,220	213,345	110,535	14,156
26										
27										
28	Rate Base :									
29	Electric Plant In Service		-	-	-	-	-	-	-	-
30	Plant Held For Future Use		-	-	-	-	-	-	-	-
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-
33	Prepayments		-	-	-	-	-	-	-	-
34	Fuel Stock		-	-	-	-	-	-	-	-
35	Materials & Supplies		-	-	-	-	-	-	-	-
36	Misc Deferred Debits		-	-	-	-	-	-	-	-
37	Cash Working Capital		340,427	148,422	51,531	71,006	27,628	26,424	13,669	1,747
38	Weatherization Loans		1,932,316	830,636	259,685	414,164	168,988	186,138	68,160	4,546
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-
40										
41	Total Rate Base Additions		2,272,744	979,058	311,216	485,170	196,616	212,562	81,829	6,293
42										
43	Rate Base Deductions :									
44	Accum Provision For Depreciation		-	-	-	-	-	-	-	-
45	Accum Provision For Amortization		-	-	-	-	-	-	-	-
46	Accum Deferred Income Taxes		-	-	-	-	-	-	-	-
47	Unamortized ITC		-	-	-	-	-	-	-	-
48	Customer Advance For Construction		-	-	-	-	-	-	-	-
49	Customer Service Deposits		-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		-	-	-	-	-	-	-	-
51										
52	Total Rate Base Deductions		-	-	-	-	-	-	-	-
53										
54	Total Rate Base		2,272,744	979,058	311,216	485,170	196,616	212,562	81,829	6,293
55										
56										
57	Return On Rate Base	5.41%	123,031	52,999	16,847	26,264	10,643	11,507	4,430	341
58	Total Operating Expenses		2,751,436	1,199,667	416,688	573,824	223,220	213,345	110,535	14,156
59	Revenue Credits		2,989,371	1,263,715	401,281	653,014	266,618	293,733	105,183	5,827
60										
61	Total Revenue Requirements		5,863,837	2,516,381	834,817	1,253,102	500,482	518,585	220,147	20,324
62										
63										
64	Return On Rate Base @ Target ROR	7.76%	176,444	76,009	24,161	37,666	15,264	16,502	6,353	489
65	Total Operating Expenses Adjusted for Taxes		2,784,256	1,213,805	421,182	580,831	226,060	216,415	111,717	14,247
66	Revenue Credits		2,989,371	1,263,715	401,281	653,014	266,618	293,733	105,183	5,827
67										
68	Total Target Revenue Requirements		5,950,071	2,553,529	846,625	1,271,510	507,942	526,650	223,252	20,562

Unit Costs @ Target ROR

PacifiCorp
Cost Of Service By Rate Schedule
State of Washington
12 Months Ending December 2013
WCA Method - (100 Summer, 100 Winter Hours) - 43%D / 57%E
7.76% Target Return on Rate Base

	Description	Washington Jurisdiction Normalized	Residential Schedule 16	Small General Service Schedule 24	Large General Service <1,000 kW Schedule 36	Large General Service >1,000 kW Schedule 48T	Large General Dedicated Facilities Schedule 48T	Agricultural Pumping Schedule 40	Street & Area Lighting Sch. 15,51-54,57
14	**UNITS**								
15	NCP KW	19,902,498	13,110,027	2,515,591	2,340,591	850,874	684,180	365,067	36,168
16	Annual KWH	4,008,166,903	1,572,834,858	543,201,559	895,773,150	386,902,405	447,981,631	148,533,366	12,939,934
17	Average Customers	132,777	104,635	18,788	1,054	61	1	5,247	2,991
18									
19									
20	**GTDRM TOTAL**	100.00%	46.45%	13.54%	19.92%	7.94%	8.08%	3.61%	0.46%
21	Revenue Requirement	352,600,969	163,792,081	47,734,808	70,232,276	28,011,710	28,476,719	12,730,015	1,623,358
22	NCP KW	17.72	12.49	18.98	30.01	32.92	41.62	34.87	44.88
23	Per KWH	0.088	0.104	0.088	0.078	0.072	0.064	0.086	0.125
24	Per Customer	2,655.58	1,565.36	2,540.64	66,639.48	459,113.33	28,476,719.02	2,426.14	542.77
25									
26	**GENERATION-TOTAL**	100.00%	43.00%	13.44%	21.43%	8.74%	9.62%	3.53%	0.24%
27	Revenue Requirement	228,734,791	98,351,484	30,746,707	49,015,377	19,996,257	22,014,968	8,069,740	540,259
28	NCP KW	11.49	7.50	12.22	20.94	23.50	32.18	22.10	14.94
29	Per KWH	0.057	0.063	0.057	0.055	0.052	0.049	0.054	0.042
30	Per Customer	1,722.69	939.95	1,636.46	46,507.95	327,739.65	22,014,967.85	1,537.96	180.63
31									
32	**GENERATION-DEMAND**	100.00%	45.13%	13.35%	20.85%	8.21%	8.85%	3.42%	0.18%
33	Revenue Requirement	98,355,960	44,386,962	13,130,720	20,511,830	8,079,631	8,705,811	3,359,972	181,035
34	NCP KW	4.94	3.39	5.22	8.76	9.50	12.72	9.20	5.01
35	Per KWH	0.025	0.028	0.024	0.023	0.021	0.019	0.023	0.014
36	Per Customer	740.76	424.21	698.87	19,462.53	132,425.56	8,705,810.59	640.36	60.53
37									
38	**GENERATION-ENERGY**	100.00%	41.39%	13.51%	21.86%	9.14%	10.21%	3.61%	0.28%
39	Revenue Requirement	130,378,831	53,964,522	17,615,987	28,503,547	11,916,626	13,309,157	4,709,768	359,224
40	NCP KW	6.55	4.12	7.00	12.18	14.01	19.45	12.90	9.93
41	Per KWH	0.033	0.034	0.032	0.032	0.031	0.030	0.032	0.028
42	Per Customer	981.94	515.74	937.59	27,045.42	195,314.09	13,309,157.26	897.61	120.11
43									
44	**TRANSMISSION-TOTAL**	100.00%	43.00%	13.42%	21.46%	8.75%	9.63%	3.51%	0.24%
45	Revenue Requirement	56,477,767	24,283,866	7,578,072	12,119,267	4,943,112	5,438,249	1,982,127	133,075
46	NCP KW	2.84	1.85	3.01	5.18	5.81	7.95	5.43	3.68
47	Per KWH	0.014	0.015	0.014	0.014	0.013	0.012	0.013	0.010
48	Per Customer	425.36	232.08	403.34	11,499.30	81,017.85	5,438,248.86	377.76	44.49
49									
50	**TRANSMISSION-DEMAND**	100.00%	45.00%	13.33%	20.92%	8.26%	8.90%	3.40%	0.19%
51	Revenue Requirement	24,285,439	10,927,294	3,237,649	5,080,524	2,005,433	2,162,344	826,843	45,350
52	NCP KW	1.22	0.83	1.29	2.17	2.36	3.16	2.26	1.25
53	Per KWH	0.006	0.007	0.006	0.006	0.005	0.005	0.006	0.004
54	Per Customer	182.90	104.43	172.32	4,820.63	32,869.15	2,162,344.46	157.58	15.16
55									
56	**TRANSMISSION-ENERGY**	100.00%	41.49%	13.48%	21.86%	9.13%	10.18%	3.59%	0.27%
57	Revenue Requirement	32,192,328	13,356,572	4,340,422	7,038,742	2,937,679	3,275,904	1,155,284	87,724
58	NCP KW	1.62	1.02	1.73	3.01	3.45	4.79	3.16	2.43
59	Per KWH	0.008	0.008	0.008	0.008	0.008	0.007	0.008	0.007
60	Per Customer	242.45	127.65	231.01	6,678.67	48,148.70	3,275,904.40	220.18	29.33

Unit Costs @ Target ROR

PacifiCorp
Cost Of Service By Rate Schedule
State of Washington
12 Months Ending December 2013
WCA Method - (100 Summer, 100 Winter Hours) - 43%D / 57%E
7.76% Target Return on Rate Base

	Description	Washington Jurisdiction Normalized	Residential Schedule 16	Small General Service Schedule 24	Large General Service <1,000 kW Schedule 36	Large General Service >1,000 kW Schedule 48T	Large General Dedicated Facilities Schedule 48T	Agricultural Pumping Schedule 40	Street & Area Lighting Sch. 15,51-54,57
61									
62	**DISTRIBUTION-TOTAL**	100.00%	60.13%	14.26%	14.32%	4.64%	0.88%	4.25%	1.52%
63	Revenue Requirement	54,640,221	32,853,370	7,789,821	7,826,236	2,535,201	482,059	2,322,143	831,391
64	NCP KW	2.75	2.51	3.10	3.34	2.98	0.70	6.36	22.99
65	Per KWH	0.014	0.021	0.014	0.009	0.007	0.001	0.016	0.064
66	Per Customer	411.52	313.98	414.61	7,425.88	41,552.08	482,059.15	442.56	277.97
67									
68	**DISTRIBUTION-SUBSTATION**	100.00%	52.06%	12.17%	19.04%	6.41%	4.22%	5.56%	0.53%
69	Revenue Requirement	7,690,164	4,003,861	936,152	1,464,490	492,976	324,236	427,697	40,752
70	NCP KW	0.39	0.31	0.37	0.63	0.58	0.47	1.17	1.13
71	Per KWH	0.002	0.003	0.002	0.002	0.001	0.001	0.003	0.003
72	Per Customer	57.92	38.26	49.83	1,389.57	8,079.90	324,236.29	81.51	13.63
73									
74	**DISTRIBUTION- P & C**	100.00%	59.09%	13.84%	14.94%	5.01%	0.38%	4.29%	2.45%
75	Revenue Requirement	28,743,517	16,985,477	3,978,659	4,294,622	1,438,649	109,574	1,231,893	704,643
76	NCP KW	1.44	1.30	1.58	1.83	1.69	0.16	3.37	19.48
77	Per KWH	0.007	0.011	0.007	0.005	0.004	0.000	0.008	0.054
78	Per Customer	216.48	162.33	211.76	4,074.93	23,579.53	109,573.95	234.78	235.60
79									
80	**DISTRIBUTION-TRANSFORMER**	100.00%	61.54%	13.77%	14.63%	4.47%	0.15%	4.94%	0.50%
81	Revenue Requirement	10,012,656	6,162,196	1,378,265	1,464,478	447,699	15,495	494,793	49,730
82	NCP KW	0.50	0.47	0.55	0.63	0.53	0.02	1.36	1.37
83	Per KWH	0.002	0.004	0.003	0.002	0.001	0.000	0.003	0.004
84	Per Customer	75.41	58.89	73.36	1,389.56	7,337.81	15,495.41	94.30	16.63
85									
86	**DISTRIBUTION-METER**	100.00%	66.54%	16.67%	8.15%	1.55%	0.92%	5.50%	0.67%
87	Revenue Requirement	2,575,738	1,713,997	429,278	209,893	40,039	23,725	141,605	17,201
88	NCP KW	0.13	0.13	0.17	0.09	0.05	0.03	0.39	0.48
89	Per KWH	0.001	0.001	0.001	0.000	0.000	0.000	0.001	0.001
90	Per Customer	19.40	16.38	22.85	199.16	656.24	23,724.59	26.99	5.75
91									
92	**DISTRIBUTION-SERVICE**	100.00%	70.98%	19.00%	6.99%	2.06%	0.16%	0.47%	0.34%
93	Revenue Requirement	5,618,146	3,987,839	1,067,466	392,752	115,839	9,029	26,156	19,065
94	NCP KW	0.28	0.30	0.42	0.17	0.14	0.01	0.07	0.53
95	Per KWH	0.001	0.003	0.002	0.000	0.000	0.000	0.000	0.001
96	Per Customer	42.31	38.11	56.81	372.66	1,898.60	9,028.89	4.98	6.37
97									
98	**RETAIL-TOTAL**	100.00%	84.58%	11.38%	0.00%	0.43%	0.22%	1.95%	1.44%
99	Revenue Requirement	6,798,118	5,749,833	773,584	(113)	29,198	14,793	132,753	98,071
100	NCP KW	0.34	0.44	0.31	(0.00)	0.03	0.02	0.36	2.71
101	Per KWH	0.002	0.004	0.001	(0.000)	0.000	0.000	0.001	0.008
102	Per Customer	51.20	54.95	41.17	(0.11)	478.55	14,792.92	25.30	32.79
103									
104	**MISC - Total**	100.00%	42.92%	14.23%	21.37%	8.54%	8.85%	3.75%	0.35%
105	Revenue Requirement	5,950,071	2,553,529	846,625	1,271,510	507,942	526,650	223,252	20,562
106	NCP KW	0.30	0.19	0.34	0.54	0.60	0.77	0.61	0.57
107	Per KWH	0.001	0.002	0.002	0.001	0.001	0.001	0.002	0.002
108	Per Customer	44.81	24.40	45.06	1,206.47	8,325.19	526,650.24	42.55	6.88

Unit Costs @ Target ROR

PacifiCorp
Cost Of Service By Rate Schedule
State of Washington
12 Months Ending December 2013
WCA Method - (100 Summer, 100 Winter Hours) - 43%D / 57%E
7.76% Target Return on Rate Base

	Description	Washington Jurisdiction Normalized	Residential Schedule 16	Small General Service Schedule 24	Large General Service <1,000 kW Schedule 36	Large General Service >1,000 kW Schedule 48T	Large General Dedicated Facilities Schedule 48T	Agricultural Pumping Schedule 40	Street & Area Lighting Sch. 15,51-54,57
109									
110	**Classification Revenue Requirement**								
111	Generation - Demand	98,355,960	44,386,962	13,130,720	20,511,830	8,079,631	8,705,811	3,359,972	181,035
112	Transmission - Demand	24,285,439	10,927,294	3,237,649	5,080,524	2,005,433	2,162,344	826,843	45,350
113	Distribution - Substation	7,690,164	4,003,861	936,152	1,464,490	492,976	324,236	427,697	40,752
114	**Demand - TOTAL Revenue Requirement**	130,331,563	59,318,117	17,304,521	27,056,844	10,578,040	11,192,391	4,614,512	267,137
115									
116	Generation - Energy	130,378,831	53,964,522	17,615,987	28,503,547	11,916,626	13,309,157	4,709,768	359,224
117	Transmission - Energy	32,192,328	13,356,572	4,340,422	7,038,742	2,937,679	3,275,904	1,155,284	87,724
118	Misc - Total	5,950,071	2,553,529	846,625	1,271,510	507,942	526,650	223,252	20,562
119	**Energy - TOTAL Revenue Requirement**	168,521,230	69,874,622	22,803,034	36,813,800	15,362,247	17,111,712	6,088,304	467,510
120									
121	Distribution - Meter	2,575,738	1,713,997	429,278	209,893	40,039	23,725	141,605	17,201
122	Distribution - Service	5,618,146	3,987,839	1,067,466	392,752	115,839	9,029	26,156	19,065
123	Retail Total	6,798,118	5,749,833	773,584	(113)	29,198	14,793	132,753	98,071
124	**Customer - TOTAL Revenue Requirement**	14,992,002	11,451,669	2,270,329	602,532	185,075	47,546	300,513	134,338
125									
126	Distribution - P&C	28,743,517	16,985,477	3,978,659	4,294,622	1,438,649	109,574	1,231,893	704,643
127	Distribution - Transformer	10,012,656	6,162,196	1,378,265	1,464,478	447,699	15,495	494,793	49,730
128	**Load Size - TOTAL Revenue Requirement**	**38,756,173**	**23,147,673**	**5,356,924**	**5,759,100**	**1,886,348**	**125,069**	**1,726,686**	**754,373**
129									
130	**Total Classification Revenue Requirement**	352,600,969	163,792,081	47,734,808	70,232,276	28,011,710	28,476,719	12,730,015	1,623,358
131	**GTDRM Revenue Requirement**	352,600,969	163,792,081	47,734,808	70,232,276	28,011,710	28,476,719	12,730,015	1,623,358
132	**Check**	-	-	-	-	-	-	-	-
133									
134	**UNITS**								
135	NCP KW	19,902,498	13,110,027	2,515,591	2,340,591	850,874	684,180	365,067	36,168
136	Annual KWH	4,008,166,903	1,572,834,858	543,201,559	895,773,150	386,902,405	447,981,631	148,533,366	12,939,934
137	Average Customers	132,777	104,635	18,788	1,054	61	1	5,247	2,991
138	Load Factor	0%	0%	0%	0%	0%	0%	0%	0%
139									
140	**100% Cost Based Rates**								
141	Demand Charge	$ 6.55	$ 4.52	$ 6.88	$ 11.56	$ 12.43	$ 16.36	$ 12.64	$ 7.39
142	Energy Charge	$ 0.0420	$ 0.0444	$ 0.0420	$ 0.0411	$ 0.0397	$ 0.0382	$ 0.0410	$ 0.0361
143	Customer Charge	$ 9.41	$ 9.12	$ 10.07	$ 47.64	$ 252.78	$ 3,962.20	$ 4.77	$ 3.74
144	Load Size Charge	$ 1.95	$ 1.77	$ 2.13	$ 2.46	$ 2.22	$ 0.18	$ 4.73	$ 20.86
145									
146	**Check**								
147	Demand Revenue Requirement	$ 130,331,563	$ 59,318,117	$ 17,304,521	$ 27,056,844	$ 10,578,040	$ 11,192,391	$ 4,614,512	$ 267,137
148	Energy Revenue Requirement	$ 168,521,230	$ 69,874,622	$ 22,803,034	$ 36,813,800	$ 15,362,247	$ 17,111,712	$ 6,088,304	$ 467,510
149	Customer Revenue Requirement	$ 14,992,002	$ 11,451,669	$ 2,270,329	$ 602,532	$ 185,075	$ 47,546	$ 300,513	$ 134,338
150	Load Size Revenue Requirement	$ 38,756,173	$ 23,147,673	$ 5,356,924	$ 5,759,100	$ 1,886,348	$ 125,069	$ 1,726,686	$ 754,373
151	Total Revenue Requirement	$ 352,600,969	$ 163,792,081	$ 47,734,808	$ 70,232,276	$ 28,011,710	$ 28,476,719	$ 12,730,015	$ 1,623,358

Exhibit No. JRS-16
Docket UE-140762 *et al.*
Witness: Joelle R. Steward

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF JOELLE R. STEWARD

Proposed Allocation of Revenue Requirement Increase

November 2014

TABLE A. PRESENT AND PROPOSED RATES
PACIFIC POWER & LIGHT COMPANY
ESTIMATED EFFECT OF PROPOSED BASE RATE INCREASE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
IN WASHINGTON
12 MONTHS ENDED DECEMBER 2013

Line No.	Description	Curr. Sch. No.	Avg. Cust.	MWH	Present Base Revenues ($000)	Proposed Base Revenues ($000)	Increase ($000)	Base %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) (7)/(5)
	Residential							
1	Residential Service	16/17/18	104,635	1,572,835	$140,088	$155,724	$15,636	11.2%
2	**Total Residential**		104,635	1,572,835	$140,088	$155,724	$15,636	11.2%
	Commercial & Industrial							
3	Small General Service	24	18,788	543,202	$48,473	$50,884	$2,411	5.0%
4	Partial Requirements Service	33	0	0	$0	$0	$0	11.2%
5	Large General Service <1,000 kW	36	1,054	895,773	$66,810	$74,267	$7,457	11.2%
6	Agricultural Pumping Service	40	5,247	148,533	$12,666	$13,296	$630	5.0%
7	Partial Requirements Service => 1,000 kW	47	1	1,995	$292	$325	$33	11.2%
8	Large General Service => 1,000 kW	48	62	834,884	$50,976	$56,666	$5,690	11.2%
9	Recreational Field Lighting	54	30	295	$26	$27	$1	5.0%
10	**Total Commercial & Industrial**		25,182	2,424,681	$179,244	$195,465	$16,221	9.0%
	Public Street Lighting							
11	Outdoor Area Lighting Service	15	2,532	3,355	$469	$492	$23	5.0%
12	Street Lighting Service	51	163	3,187	$621	$652	$31	5.0%
13	Street Lighting Service	52	15	198	$34	$35	$2	5.0%
14	Street Lighting Service	53	217	4,162	$286	$301	$14	5.0%
15	Street Lighting Service	57	34	1,743	$213	$224	$11	5.0%
16	**Total Public Street Lighting**		2,961	12,645	$1,622	$1,703	$81	5.0%
17	**Total Sales to Standard Tariff Customers**		132,778	4,010,161	$320,954	$352,893	$31,939	10.0%
18	Total AGA				$652	$652		
19	**Total Sales to Ultimate Consumers**		132,778	4,010,161	$321,606	$353,544	$31,939	9.9%

TABLE B. PRESENT AND PROPOSED RATES
PACIFIC POWER & LIGHT COMPANY
ESTIMATED EFFECT OF PROPOSED DEFERRAL SURCHARGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
IN WASHINGTON
12 MONTHS ENDED DECEMBER 2013

Line No.	Description	Curr. Sch. No.	Avg. Cust.	MWH	Proposed Base Revenues ($000)	Change: Increase ($000)	Change: Deferral %	Deferral Surcharge (cents/kWh)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Residential							
1	Residential Service	16/17/18	104,635	1,572,835	$155,724	$2,579	1.8%	0.164
2	**Total Residential**		104,635	1,572,835	$155,724	$2,579	1.8%	
	Commercial & Industrial							
3	Small General Service	24	18,788	543,202	$50,884	$842	1.7%	0.155
4	Partial Requirements Service	33	0	0	$0	$0	1.9%	0.138
5	Large General Service <1,000 kW	36	1,054	895,773	$74,267	$1,236	1.9%	0.138
6	Agricultural Pumping Service	40	5,247	148,533	$13,296	$221	1.7%	0.149
7	Partial Requirements Service => 1,000 kW	47	1	1,995	$325	$2	0.8%	0.113
8	Large General Service => 1,000 kW	48	62	834,884	$56,666	$943	1.9%	0.113
9	Recreational Field Lighting	54	30	295	$27	$0	1.7%	0.153
10	**Total Commercial & Industrial**		25,182	2,424,681	$195,465	$3,246	1.8%	
	Public Street Lighting							
11	Outdoor Area Lighting Service	15	2,532	3,355	$492	$8	1.7%	0.243
12	Street Lighting Service	51	163	3,187	$652	$11	1.7%	0.340
13	Street Lighting Service	52	15	198	$35	$1	1.7%	0.294
14	Street Lighting Service	53	217	4,162	$301	$5	1.7%	0.120
15	Street Lighting Service	57	34	1,743	$224	$4	1.7%	0.213
16	**Total Public Street Lighting**		2,961	12,645	$1,703	$28	1.7%	
17	**Total Sales to Standard Tariff Customers**		132,778	4,010,161	$352,893	$5,853	1.8%	0.146
18	Total AGA				$652			
19	**Total Sales to Ultimate Consumers**		132,778	4,010,161	$353,544	$5,853	1.8%	

TABLE C. PRESENT AND PROPOSED RATES
PACIFIC POWER & LIGHT COMPANY
ESTIMATED COMBINED EFFECT OF PROPOSED BASE RATE INCREASE AND DEFERRAL SURCHARGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
IN WASHINGTON
12 MONTHS ENDED DECEMBER 2013

Line No.	Description	Curr. Sch. No.	Avg. Cust.	MWH	Present Revenues ($000)	Proposed Revenues ($000)	Change ($000)	Change %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) (7)/(5)
	Residential							
1	Residential Service	16/17/18	104,635	1,572,835	$140,088	$158,304	$18,216	13.0%
2	**Total Residential**		104,635	1,572,835	$140,088	$158,304	$18,216	13.0%
	Commercial & Industrial							
3	Small General Service	24	18,788	543,202	$48,473	$51,726	$3,253	6.7%
4	Partial Requirements Service	33	0	0	$0	$0	$0	13.0%
5	Large General Service <1,000 kW	36	1,054	895,773	$66,810	$75,503	$8,693	13.0%
6	Agricultural Pumping Service	40	5,247	148,533	$12,666	$13,517	$851	6.7%
7	Partial Requirements Service => 1,000 kW	47	1	1,995	$292	$327	$35	12.0%
8	Large General Service => 1,000 kW	48	62	834,884	$50,976	$57,609	$6,633	13.0%
9	Recreational Field Lighting	54	30	295	$26	$28	$2	6.7%
10	**Total Commercial & Industrial**		25,182	2,424,681	$179,244	$198,711	$19,467	10.9%
	Public Street Lighting							
11	Outdoor Area Lighting Service	15	2,532	3,355	$469	$500	$32	6.7%
12	Street Lighting Service	51	163	3,187	$621	$663	$42	6.8%
13	Street Lighting Service	52	15	198	$34	$36	$2	6.7%
14	Street Lighting Service	53	217	4,162	$286	$306	$19	6.8%
15	Street Lighting Service	57	34	1,743	$213	$227	$14	6.8%
16	**Total Public Street Lighting**		2,961	12,645	$1,622	$1,732	$110	6.8%
17	**Total Sales to Standard Tariff Customers**		132,778	4,010,161	$320,954	$358,746	$37,792	11.8%
18	Total AGA				$652	$652		
19	**Total Sales to Ultimate Consumers**		132,778	4,010,161	$321,606	$359,398	$37,792	11.8%

Exhibit No. JRS-17
Docket UE-140762 *et al.*
Witness: Joelle R. Steward

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF JOELLE R. STEWARD

Proposed Prices and Billing Determinants

November 2014

PACIFIC POWER & LIGHT COMPANY
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2013
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars	Distribution Price	Distribution Dollars	Transmission Price	Transmission Dollars	Generation Price	Generation Dollars
SCHEDULE 15											
Outdoor Area Lighting Service-Grand Combined											
Mercury Vapor Lamp Charges											
7,000 Lumens	27,329	$10.63	$290,508	$11.16	$304,993	$6.53	$178,332	$0.92	$25,033	$3.71	$101,628
21,000 Lumens	4,371	$20.23	$88,427	$21.24	$92,842	$12.42	$54,285	$1.74	$7,620	$7.08	$30,936
55,000 Lumens	540	$41.86	$22,620	$43.94	$23,744	$25.69	$13,883	$3.61	$1,949	$14.64	$7,912
High Pressure Sodium Vapor Lamp Charges											
5,800 Lumens	1,979	$12.09	$23,929	$12.69	$25,117	$7.42	$14,686	$1.04	$2,062	$4.23	$8,369
22,000 Lumens	1,668	$17.76	$29,629	$18.64	$31,097	$10.90	$18,183	$1.53	$2,552	$6.21	$10,362
50,000 Lumens	502	$28.64	$14,384	$30.07	$15,102	$17.58	$8,830	$2.47	$1,240	$10.02	$5,032
Pole Charges	610	$1.00	$610	$1.00	$610	$1.00	$610		$0		$0
NPC-Base - NPC per kWh *	3,367,563			0.000 ¢	$0		$0		$0	0.000 ¢	$0
Total Bills	30,383										
Subtotal	3,367,563		$470,107		493,504		288,810		40,455		164,240
Unbilled	(12,328)		($1,473)		($1,473)		($862)		($121)		($490)
Total	3,355,235		$468,634		$492,031		$287,948		$40,334		$163,750
*Included in Generation Price											
SCHEDULE 16/18											
Residential Service-Combined											
Basic Charge	1,255,621	$7.75	$9,731,064	$14.00	$17,313,810	$14.00	$17,313,809		$0		$0
1st 600 kWh	673,194,199	6.199 ¢	$41,731,308	3.946 ¢	$26,564,242	1.081 ¢	$7,274,009	1.142 ¢	$7,687,227	1.723 ¢	$11,603,006
All addt'l kWh	905,507,102	9.817 ¢	$88,893,632	5.893 ¢	$53,361,533	1.614 ¢	$14,611,832	1.705 ¢	$15,441,894	2.574 ¢	$23,307,806
kW demand	5,446	$1.65	$8,985	$1.83	$9,989		$0		$0	1.834	$9,989
Minimum kW Charge	723	$3.20	$2,313	$3.60	$2,603		$0		$0	$3.60	$2,603
kW demand in minimum	70	($1.65)	($116)	($1.83)	($129)		$0		$0	($1.83)	($128)
NPC-Base - 1st 600 kWh	673,194,199			2.634 ¢	$17,731,935		$0		$0	2.634 ¢	$17,731,935
NPC-Base - All Addt'l kWh	905,507,102			4.530 ¢	$41,019,472		$0		$0	4.530 ¢	$41,019,472
Total Rate - 1st 600 kWh		6.199 ¢		6.580 ¢		1.081 ¢		1.142 ¢		4.357 ¢	
Total Rate - All Addt'l kWh		9.817 ¢		10.423 ¢		1.614 ¢		1.705 ¢		7.104 ¢	
Subtotal	1,578,701,302		$140,367,186		$156,003,455		$39,199,650		$23,129,121		$93,674,683
Unbilled	(5,866,445)		(279,067)		($279,067)		($70,122)		($41,375)		($167,570)
Total	1,572,834,857		$140,088,119		$155,724,388		$39,129,528		$23,087,747		$93,507,113
SCHEDULE 16											
Residential Service											
Includes Schedule 16 Net Metering											
Basic Charge	1,203,933	$7.75	$9,330,480	$14.00	$16,855,061	$14.00	$16,855,061		$0		$0
1st 600 kWh	644,426,915	6.199 ¢	$39,948,024	3.946 ¢	$25,429,086	1.081 ¢	$6,963,172	1.142 ¢	$7,358,732	1.723 ¢	$11,100,736
All addt'l kWh	866,994,099	9.817 ¢	$85,112,811	5.893 ¢	$51,091,962	1.614 ¢	$13,990,362	1.705 ¢	$14,785,120	2.574 ¢	$22,316,479
kW demand	0	$1.65	$0	$1.83	$0		$0		$0	$1.83	$0
Minimum kW Charge	0	$3.20	$0	$3.60	$0		$0		$0	$3.60	$0
NPC-Base - 1st 600 kWh	644,426,915			2.634 ¢	$16,974,205		$0		$0	2.634 ¢	$16,974,205
NPC-Base - All Addt'l kWh	866,994,099			4.530 ¢	$39,274,833		$0		$0	4.530 ¢	$39,274,833
kW demand in minimum	0	($1.65)	$0	($1.83)	$0		$0		$0	($1.83)	$0
Subtotal	1,511,421,015		$134,391,315		$149,625,147		$37,808,595		$22,143,852		$89,666,253
Unbilled	(5,617,740)		(267,238)		($267,238)		($67,150)		($39,621)		($160,467)
Total	1,505,803,275		$134,124,077		$149,357,908		$37,741,445		$22,104,231		$89,505,785

PACIFIC POWER & LIGHT COMPANY
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2013
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars	Distribution Price	Distribution Dollars	Transmission Price	Transmission Dollars	Generation Price	Generation Dollars
SCHEDULE 17											
Residential Service											
Basic Charge	50,454	$7.75	$391,022	$8.75	$441,477	$8.75	$441,477		$0		$0
1st 600 kWh	28,090,300	6.199 ¢	$1,741,318	3.946 ¢	$1,108,443	1.081 ¢	$303,522	1.142 ¢	$320,764	1.723 ¢	$483,876
All addt'l kWh	36,551,662	9.817 ¢	$3,588,277	5.893 ¢	$2,153,989	1.614 ¢	$589,821	1.705 ¢	$623,327	2.574 ¢	$940,842
kW demand	0	$1.65	$0	$1.83	$0	$0.00	$0	$0.00	$0	$1.83	$0
Minimum kW Charge	0	$3.20	$0	$3.60	$0	$0.00	$0	$0.00	$0	$3.60	$0
kW demand in minimum	0	($1.65)	$0	($1.83)	$0	$0.00	$0	$0.00	$0	($1.83)	$0
NPC-Base - 1st 600 kWh	28,090,300			2.634 ¢	$739,899	¢	$0	¢	$0	2.634 ¢	$739,899
NPC-Base - All Addt'l kWh	36,551,662			4.530 ¢	$1,655,790	¢	$0	¢	$0	4.530 ¢	$1,655,790
Subtotal	64,641,963		$5,720,617		$6,099,598		$1,334,819		$944,091		$3,820,407
Unbilled	(238,854)		(11,315)		($11,315)		($2,843)		($1,678)		($6,794)
Total	64,403,109		$5,709,302		$6,088,283		$1,331,976		$942,413		$3,813,612
SCHEDULE 24											
Small General Service-Grand Combined											
Seasonal											
Single Phase	1	$104.52	$105	$120.00	$120	$120.00	$120		$0		$0
Three Phase	86	$155.76	$13,429	$180.00	$15,519	$180.00	$15,519		$0		$0
Load Size > 15 kW	3,361	$11.04	$37,103	$12.00	$40,329	$12.00	$40,329		$0		$0
Basic Charge											
Single Phase	164,391	$8.71	$1,431,841	$10.00	$1,643,906	$10.00	$1,643,906		$0		$0
Three Phase	63,164	$12.98	$819,872	$15.00	$947,463	$15.00	$947,463		$0		$0
Load Size > 15 kW	1,251,783	$0.92	$1,151,641	$1.00	$1,251,783	$1.00	$1,251,783		$0		$0
Total Basic Charges	227,555										
Total Bills	225,462										
All kW >15	856,089	$3.61	$3,090,481	$3.77	$3,227,454	$0.81	$692,744	$1.06	$909,283	$1.90	$1,624,493
1st 1,000 kWh	131,966,941	10.359 ¢	$13,670,457	6.282 ¢	$8,290,165	1.348 ¢	$1,779,409	1.771 ¢	$2,335,620	3.163 ¢	$4,172,736
Next 8,000 kWh	289,086,889	7.156 ¢	$20,687,058	4.341 ¢	$12,549,261	0.932 ¢	$2,693,585	1.224 ¢	$3,535,552	2.185 ¢	$6,316,491
All additional kWh	123,964,295	6.166 ¢	$7,643,639	3.740 ¢	$4,636,265	0.803 ¢	$995,132	1.054 ¢	$1,306,193	1.883 ¢	$2,333,598
Excess Kvar	118,638	56.00 ¢	$66,437	56.00 ¢	$66,437		$0	11.00 ¢	$13,137	45.00 ¢	$53,300
NPC-Base - 1st 1,000 kWh	131,966,941			4.529 ¢	$5,976,782		$0		$0	4.529 ¢	$5,976,782
NPC-Base -Next 8,000 kWh	289,086,889			3.127 ¢	$9,039,748		$0		$0	3.127 ¢	$9,039,748
NPC-Base - All Additional kWh	123,964,295			2.695 ¢	$3,349,666		$0		$0	2.695 ¢	$3,349,666
Total Rate - 1st 1,000 kWh		10.359 ¢		10.811 ¢		1.348 ¢		1.771 ¢		7.692 ¢	
Total Rate - Next 8,000 kWh		7.156 ¢		7.468 ¢		0.932 ¢		1.224 ¢		5.312 ¢	
Total Rate - All Additional kWh		6.166 ¢		6.435 ¢		0.803 ¢		1.054 ¢		4.578 ¢	
Discounts		-1.0%		-1.0%		-1.0%		-1.0%		-1.0%	
Single Phase	72	$8.71	($6)	$10.00	($7)	$10.00	($7)		$0		$0
Three Phase	39	$12.98	($5)	$15.00	($5)	$15.00	($6)		$0		$0
Load Size > 15 kW	1,129	$0.92	($11)	$1.00	($11)	$1.00	($11)		$0		$0
All kW	948	$3.61	($35)	$3.77	($36)	$0.81	($8)	$1.06	($10)	$1.90	($18)
1st 1,000 kWh	90,642	10.359 ¢	($94)	6.282 ¢	($57)	1.348	($12)	1.771 ¢	($16)	3.163 ¢	($29)
Next 8,000 kWh	455,824	7.156 ¢	($326)	4.341 ¢	($198)	0.932	($42)	1.224 ¢	($56)	2.185 ¢	($100)
All additional kWh	176,780	6.166 ¢	($109)	3.740 ¢	($66)	0.803	($14)	1.054 ¢	($19)	1.883 ¢	($33)
Excess Kvar	1,148	56.00 ¢	($6)	56.00 ¢	($6)		$0	11.00 ¢	($6)	45.00 ¢	($517)
High Voltage Charge	123	$60.00	$7,408	$60.00	$7,408		$0	$11.86	$1,465	$48.14	$5,943
Load Size Discount	1,129	(30.00) ¢	($339)	(30.00) ¢	($339)	(30.00) ¢	($339)		$0		$0
NPC-Base - 1st 1,000 kWh	90,642			4.529 ¢	($2,211)		$0		$0	4.529 ¢	($2,211)
NPC-Base -Next 8,000 kWh	455,824			3.127 ¢	($746)		$0		$0	3.127 ¢	($746)
NPC-Base - All Additional kWh	176,780			2.695 ¢	($127)		$0		$0	2.695 ¢	($127)
Subtotal	545,018,125		$48,618,540		$51,029,669		$10,059,550		$8,101,143		$32,868,976
Unbilled	(1,816,568)		($145,444)		($145,444)		($28,671)		($23,090)		($93,682)
Total	543,201,557		$48,473,096		$50,884,225		$10,030,879		$8,078,053		$32,775,294

PACIFIC POWER & LIGHT COMPANY
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2013
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars	Distribution Price	Distribution Dollars	Transmission Price	Transmission Dollars	Generation Price	Generation Dollars
SCHEDULE 33											
Partial Requirements Service											
Basic Charge											
<=100 kW	0	$259.00	$0	$259.00	$0	$259.00	$0		$0		$0
101 - 300 kW	0	$96.00	$0	$96.00	$0	$96.00	$0		$0		$0
>300 kW	0	$192.00	$0	$192.00	$0	$192.00	$0		$0		$0
Total Basic Charges	0										
101 - 300 kW	0	$1.70	$0	$1.89	$0	$1.89	$0		$0		$0
>300 kW	0	$1.39	$0	$1.55	$0	$1.55	$0		$0		$0
Demand Charges											
All kW	0	$4.72	$0	$5.87	$0	$0.95	$0	$0.98	$0	$3.94	$0
Energy Charges											
1st 40,000 kWh	0	5.629 ¢	$0	2.678 ¢	$0	¢	$0	1.207 ¢	$0	1.471 ¢	$0
All additional kWh	0	5.157 ¢	$0	2.452 ¢	$0	¢	$0	1.105 ¢	$0	1.347 ¢	$0
Excess Kvar	0	56.0 ¢	$0	56.0 ¢	$0	¢	$0	11.0 ¢	$0	45.0 ¢	$0
Excess Kvarh	0	0.06 ¢	$0	0.06 ¢	$0	¢	$0	0.01 ¢	$0	0.05 ¢	$0
NPC-Base - 1st 40,000 kWh	0			3.415 ¢	$0	¢	$0	¢	$0	3.415 ¢	$0
NPC-Base - All additional kWh	0			3.131	$0		$0		$0	3.131	$0
Discounts		-1.0%		-1.0%		-1.0%		-1.0%		-1.0%	
<=100 kW	0	$259.00	$0	$259.00	$0	$259.00	$0		$0		$0
101 - 300 kW	0	$96.00	$0	$96.00	$0	$96.00	$0		$0		$0
>300 kW	0	$192.00	$0	$192.00	$0	$192.00	$0		$0		$0
101 - 300 kW	0	$1.70	$0	$1.89	$0	$1.89	$0		$0		$0
>300 kW	0	$1.39	$0	$1.55	$0	$1.55	$0		$0		$0
All kW	0	$4.72	$0	$5.87	$0	$0.95	$0	$0.98	$0	$3.94	$0
1st 40,000 kWh	0	$0.00 ¢	$0	$0.00 ¢	$0	$0.00 ¢	$0	$0.00 ¢	$0	$0.00 ¢	$0
All additional kWh	0	5.157 ¢	$0	2.452 ¢	$0	¢	$0	1.105 ¢	$0	1.347 ¢	$0
Excess kVar	0	56.00 ¢	$0	56.00 ¢	$0	¢	$0	11.00 ¢	$0	45.00 ¢	$0
Excess kVarh	0	0.06 ¢	$0	0.06 ¢	$0	¢	$0	0.01 ¢	$0	0.05 ¢	$0
High Voltage Charge--Primary	0	$60.00	$0	$60.00	$0	$60.00	$0	$60.00	$0	$60.00	$0
Load Size Discount - Primary	0	(30.00) ¢	$0	(30.00) ¢	$0	(30.00) ¢	$0	(30.00) ¢	$0	(30.00) ¢	$0
Standby kW	0	$2.36		$2.94	$0	$0.48	$0	$0.49	$0	$1.97	$0
Overrun kW	0	$18.88		$23.48	$0	$3.80	$0	$3.92	$0	$15.76	$0
Overrun kWh	0	20.628 ¢	$0	9.808 ¢	$0	0.000 ¢	$0	4.420 ¢	$0	5.388 ¢	$0
NPC-Base - 1st 40,000 kWh	0			3.415 ¢	$0	¢	$0	¢	$0	3.415 ¢	$0
NPC-Base - All additional kWh	0			3.131 ¢	$0	¢	$0	¢	$0	3.131 ¢	$0
Subtotal	0		$0		$0		$0		$0		$0
Unbilled	0		$0		$0		$0		$0		$0
Total	0		$0		$0		$0		$0		$0

PACIFIC POWER & LIGHT COMPANY
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2013
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars	Distribution Price	Distribution Dollars	Transmission Price	Transmission Dollars	Generation Price	Generation Dollars
SCHEDULE 36											
Large General Service < 1,000 kW-Grand Combined											
Basic Charge											
<=100 kW	316	$259.00	$81,956	$259.00	$81,956	$259.00	$81,956		$0		$0
101 - 300 kW	8,727	$96.00	$837,779	$96.00	$837,779	$96.00	$837,779		$0		$0
>300 kW	3,604	$192.00	$691,904	$192.00	$691,904	$192.00	$691,904		$0		$0
Total Basic Charges	12,647										
101 - 300 kW	1,502,047	$1.70	$2,553,480	$1.89	$2,838,869	$1.89	$2,838,869		$0		$0
>300 kW	1,828,696	$1.39	$2,541,887	$1.55	$2,834,479	$1.55	$2,834,479		$0		$0
Demand Charges											
All kW	2,516,584	$4.72	$11,878,274	$5.87	$14,772,345	$0.95	$2,396,111	$0.98	$2,465,185	$3.94	$9,911,049
Minimum kW	1,999	$4.72	$9,434	$5.87	$11,732	$0.95	$1,899	$0.98	$1,959	$3.94	$7,875
Energy Charges											
1st 40,000 kWh	396,791,152	5.629 ¢	$22,335,374	2.678 ¢	$10,626,067		$0	1.207 ¢	$4,789,221	1.471 ¢	$5,836,844
All additional kWh	502,951,620	5.157 ¢	$25,937,215	2.452 ¢	$12,332,374		$0	1.105 ¢	$5,558,263	1.347 ¢	$6,774,110
Excess Kvar	497,320	56.00 ¢	$278,499	56.00 ¢	$278,499		$0	11.00 ¢	$55,209	45.00 ¢	$223,290
NPC-Base - 1st 40,000 kWh	396,791,152			3.415 ¢	$13,550,418		$0		$0	3.415 ¢	$13,550,418
NPC-Base - All additional kWh	502,951,620			3.131 ¢	$15,747,415		$0		$0	3.131 ¢	$15,747,415
Total Rate - 1st 40,000 kWh		5.629 ¢		6.093 ¢		-		1.207 ¢		4.886 ¢	
Total Rate - All additional kWh		5.157 ¢		5.583 ¢		-		1.105 ¢		4.478 ¢	
Discounts		-1.0%		-1.0%		-1.0%		-1.0%		-1.0%	
<=100 kW	0	$259.00	($1)	$259.00	($1)	$259.00	($1)		$0		$0
101 - 300 kW	69	$96.00	($66)	$96.00	($66)	$96.00	($66)		$0		$0
>300 kW	82	$192.00	($157)	$192.00	($157)	$192.00	($157)		$0		$0
101 - 300 kW	10,765	$1.70	($183)	$1.89	($203)	$1.89	($203)		$0		$0
>300 kW	57,957	$1.39	($806)	$1.55	($898)	$1.55	($898)		$0		$0
All kW	44,958	$4.72	($2,122)	$5.87	($2,639)	$0.95	($427)	$0.98	($441)	$3.94	($1,771)
Minimum kW	384	$4.72	($18)	$5.87	($23)	$0.95	($4)	$0.98	($4)	$3.94	($15)
1st 40,000 kWh	5,159,480	5.629 ¢	($2,904)	2.678 ¢	($1,382)		$0	1.207 ¢	($623)	1.471 ¢	($759)
All additional kWh	11,810,179	5.157 ¢	($6,090)	2.452 ¢	($2,896)		$0	1.105 ¢	($1,305)	1.347 ¢	($1,591)
Excess Kvar	8,798	56.00 ¢	($50)	56.00 ¢	($50)		$0	11.00 ¢	($9)	45.00 ¢	($39)
High Voltage Charge	151	$60.00	$9,036	$60.00	$9,036		$0	$11.89	$1,791	$48.11	$7,245
Load Size Discount	68,722	(30.00) ¢	($20,617)	(30.00) ¢	($20,617)	(30.00) ¢	($20,617)		$0	0.00	$0
NPC-Base - 1st 40,000 kWh	5,159,480			3.415 ¢	($1,762)		$0		$0	3.415 ¢	($1,762)
NPC-Base - All additional kWh	11,810,179			3.131 ¢	($3,698)		$0		$0	3.131 ¢	($3,698)
Subtotal	899,742,772		$67,121,824		$74,578,481		$9,660,624		$12,869,247		$52,048,610
Unbilled	(3,969,621)		($311,648)		($311,648)		($40,370)		($53,778)		($217,500)
Total	895,773,151		$66,810,176		$74,266,833		$9,620,255		$12,815,469		$51,831,109

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	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars	Distribution Price	Distribution Dollars	Transmission Price	Transmission Dollars	Generation Price	Generation Dollars
SCHEDULE 40											
Agricultural Pumping Service-Grand Combined											
Annual Load Size Charge											
Single Phase Bills	1,050	$0.00	$0	$0.00	$0	$0.00	$0		$0		$0
Three Phase Bills											
< 51 kW	3,762	$0.00	$0	$0.00	$0	$0.00	$0		$0		$0
< 301 kW	422	$357.00	$150,550	$375.00	$158,141	$375.00	$158,141		$0		$0
> 300 kW	13	$1,457.00	$18,941	$1,530.00	$19,890	$1,530.00	$19,890		$0		$0
Total Bills	5,247										
Monthly Bills	38,717										
Customer Count	5,792										
Annual Load Size kW Charge											
Single Phase kW	3,152	$25.27	$79,651	$26.52	$83,618	$26.52	$83,618		$0		$0
Three Phase kW											
< 51 kW	51,993	$25.17	$1,308,725	$26.41	$1,373,387	$26.41	$1,373,387		$0		$0
< 301 kW	40,499	$17.53	$709,890	$18.40	$745,247	$18.40	$745,247		$0		$0
> 300 kW	5,276	$13.72	$72,376	$14.40	$75,981	$14.40	$75,981		$0		$0
Single Phase Minimum Bills	591	$75.80	$44,765	$79.57	$46,994	$79.57	$46,994		$0		$0
Three Phase <51kW Minimum Bi	1,018	$151.03	$153,760	$158.49	$161,356	$158.49	$161,356		$0		$0
KW in Minimum											
Single Phase kW	41	($25.27)	($1,043)	($26.52)	($1,095)	($26.52)	($1,095)	$0.00	$0	$0.00	$0
Three Phase <51kW, kW	311	($25.17)	($7,828)	($26.41)	($8,215)	($26.41)	($8,215)	$0.00	$0	$0.00	$0
Energy Charges	0										
All kWh	148,745,367	6.816 ¢	$10,138,484	3.914 ¢	$5,821,893	0.100	$148,919	1.391 ¢	$2,069,280	2.423 ¢	$3,603,726
Excess Kvar	54,173	56.00 ¢	$30,337	56.00 ¢	$30,337		$0	11.00 ¢	$5,982	45.00 ¢	$24,355
NPC-Base - All kWh	148,745,367			3.241 ¢	$4,820,837		$0		$0	3.241 ¢	$4,820,837
Total Rate - All kWh		6.816 ¢		7.155 ¢		0.100 ¢		1.391 ¢		5.664 ¢	
Discounts		-1.0%		-1.0%		-1.0%		-1.0%		-1.0%	
Single Phase	0	$0.00	$0	$0.00	$0	$0.00	$0		$0		$0
Three Phase											
< 51 kW	1	$0.00	$0	$0.00	$0	$0.00	$0		$0		$0
< 301 kW	0	$357.00	$0	$375.00	$0	$375.00	$0		$0		$0
> 300 kW	0	$1,457.00	$0	$1,530.00	$0	$1,530.00	$0		$0		$0
Single Phase	0	$25.27	$0	$26.52	$0	$26.52	$0		$0		$0
Three Phase											
< 51 kW	30	$25.17	($8)	$26.41	($8)	$26.41	($8)		$0		$0
< 301 kW	0	$17.53	$0	$18.40	$0	$18.40	$0		$0		$0
> 300 kW	0	$13.72	$0	$14.40	$0	$14.40	$0		$0		$0
Single Phase Min	0	$75.80	$0	$79.57	$0	$79.57	$0		$0		$0
Three Phase <51kW Min	0	$151.03	$0	$158.49	$0	$158.49	$0		$0		$0
KW in Minimum											
Single Phase kW	0	($25.27)	$0	($26.52)	$0	($26.52)	$0	$0.00	$0	$0.00	$0
Three Phase <51kW, kW	0	($25.17)	$0	($26.41)	$0	($26.41)	$0	$0.00	$0	$0.00	$0
Energy Charges											
All kWh	32,140	6.816 ¢	($22)	3.914 ¢	($13)	0.100	($32)	1.391 ¢	($4)	2.423 ¢	($8)
Excess Kvar	0	56.00 ¢	$0	56.00 ¢	$0		$0	11.00 ¢	$0	45.00 ¢	$0
High Voltage Charge	12	$60.00	$720	$60.00	$720		$0	$11.83	$142	$48.17	$578
Load Size Discount	30	(30.00) ¢	($9)	(30.00) ¢	($9)	(30.00) ¢	($9)	-	$0	-	$0
NPC-Base - All kWh	32,140			3.241 ¢	($10)		$0		$0	3.241 ¢	($10)
Subtotal	148,745,367		$12,699,289		$13,329,051		$2,804,173		$2,075,400		$8,449,478
Unbilled	(212,000)		($33,000)		($33,000)		($6,943)		($5,138)		($20,919)
Total	148,533,367		$12,666,289		$13,296,051		$2,797,231		$2,070,261		$8,428,559

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	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars	Distribution Price	Distribution Dollars	Transmission Price	Transmission Dollars	Generation Price	Generation Dollars
SCHEDULE 47T											
Large Partial Requirements Service - Secondary											
Basic Charge											
<=3000 kW	12	$1,386.00	$16,632	$1,386.00	$16,632	$1,386.00	$16,632		$0		$0
>3000 kW	0	$1,675.00	$0	$1,675.00	$0	$1,675.00	$0		$0		$0
Total Basic Charges	12					$0.00		$0.00		$0.00	
<=3000 kW variable	22,168	$1.06	$23,498	$1.18	$26,158	$1.18	$26,158		$0		$0
>3000 kW variable	0	$0.96	$0	$1.07	$0	$1.07	$0		$0		$0
All kW	18,457	$7.55	$139,353	$8.48	$156,519	$1.11	$20,488	$1.46	$26,948	$5.91	$109,083
Energy Charges											
All kWh	2,027,000	4.514 ¢	$91,499	2.067 ¢	$41,898		$0	0.995 ¢	$20,169	1.072 ¢	$21,729
Excess Kvar	9,916	$0.55	$5,454	$0.55	$5,454		$0	$0.11	$1,091	$0.44	$4,363
Excess Kvarh	0	$0.00060	$0	$0.00060	$0	$0.00000	$0	$0.00012	$0	$0.00048	$0
Standby kW	5,796	$3.78	$21,880	$4.24	$24,575	$0.56	$3,217	$0.73	$4,231	$2.96	$17,127
Overrun kW	0	$30.20	$0	$33.92	$0	$4.44	$0	$5.84	$0	$23.64	$0
Overrun kWh	0	18.056 ¢	$0	20.072 ¢	$0		$0	3.980 ¢	$0	16.092 ¢	$0
NPC-Base - All kWh	2,027,000			2.951 ¢	$59,817		$0		$0	2.951 ¢	$59,817
Subtotal	2,027,000		$298,316		$331,053		$66,495		$52,439		$212,119
Unbilled	(32,468)		($6,188)		($6,188)		($679)		($1,092)		($4,417)
Total	1,994,532		$292,128		$324,865		$65,816		$51,347		$207,702
SCHEDULE 48T											
Large General Service 1,000 kW and over-Grand Combined											
Basic Charge											
<=3000 kW	732		$1,019,061		$1,019,061		$1,019,061		$0		$0
>3000 kW	12		$30,336		$32,964		$32,964		$0		$0
Total Basic Charges	744										
<=3000 kW variable	1,083,308		$1,030,814		$1,151,944		$1,151,944		$0		$0
>3000 kW variable	693,243		$159,446		$187,176		$187,176		$0		$0
All kW	1,561,051		$11,622,887		$13,052,432		$1,835,249		$2,222,755		$8,994,428
Energy Charges											
All kWh	846,205,773		$37,776,458		$16,827,705		$0		$8,299,314		$8,528,391
Excess Kvar	365,869		$197,389		$197,389		$0		$39,112		$158,277
NPC-Base - All kWh	390,931,773				$29,276,382		$3,211,051		$5,166,284		$20,899,048
Subtotal	846,205,773		$51,836,391		$57,526,097		$4,226,394		$10,561,181		$42,738,522
Unbilled	(11,321,736)		($860,116)		($860,116)		($55,597)		($159,402)		($645,117)
Total	834,884,037		$50,976,275		$56,665,981		$4,170,797		$10,401,779		$42,093,405
SCHEDULE 48T											
Large General Service 1,000 kW and over-Combined											
Basic Charge											
<=3000 kW	732		$1,019,061		$1,019,061		$1,019,061		$0		$0
>3000 kW	0		$0		$0		$0		$0		$0
Total Basic Charges	732		$0		$0		$0		$0		$0
<=3000 kW variable	1,083,308		$1,030,814		$1,151,944		$1,151,944		$0		$0
>3000 kW variable	0		$0		$0		$0		$0		$0
All kW	879,355		$6,612,421		$7,428,440		$1,040,046		$1,266,213		$5,122,181
Energy Charges											
All kWh	390,931,773		$17,607,820		$7,685,803		$0		$3,880,204		$3,805,599
Excess Kvar	182,554		$100,232		$100,232		$0		$19,867		$80,365
NPC-Base - All kWh	390,931,773		$0		$11,890,902		$0		$0		$11,890,902
Subtotal	390,931,773		$26,370,348		$29,276,382		$3,211,051		$5,166,284		$20,899,048
Unbilled	(4,029,366)		($334,738)		($334,738)		($36,714)		($59,070)		($238,954)
Total	386,902,407		$26,035,610		$28,941,644		$3,174,337		$5,107,214		$20,660,094

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	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars	Distribution Price	Distribution Dollars	Transmission Price	Transmission Dollars	Generation Price	Generation Dollars
SCHEDULE 48T											
Large General Service 1,000 kW and over-Secondary Combined											
Basic Charge											
<=3000 kW	602	$1,386.00	$834,204	$1,386.00	$834,204	$1,386.00	$834,204		$0		$0
>3000 kW	0	$1,675.00	$0	$1,675.00	$0	$1,675.00	$0		$0		$0
Total Basic Charges	602										
<=3000 kW variable	861,624	$1.06	$913,322	$1.18	$1,016,717	$1.18	$1,016,717		$0		$0
>3000 kW variable	0	$0.96	$0	$1.07	$0	$1.07	$0		$0		$0
All kW	701,279	$7.55	$5,294,655	$8.48	$5,946,844	$1.11	$777,242	$1.46	$1,024,642	$5.91	$4,144,960
Energy Charges											
All kWh	320,313,337	4.514 ¢	$14,458,944	2.067 ¢	$6,620,877		$0	0.995 ¢	$3,185,816	1.072 ¢	$3,435,061
Excess Kvar	165,243	$0.55	$90,884	$0.55	$90,884		$0	$0.11	$18,014	$0.44	$72,870
NPC-Base - All kWh	320,313,337			2.951 ¢	$9,452,447		$0		$0	2.951 ¢	$9,452,447
Total Rate - All kWh		4.514 ¢		5.018 ¢				0.995 ¢		4.023 ¢	
Subtotal	320,313,337		$21,592,009		$23,961,973		$2,628,163		$4,228,472		$17,105,338
Unbilled	(3,730,095)		(313,023)		($313,023)		($34,333)		($55,238)		($223,452)
Total	316,583,242		$21,278,986		$23,648,950		$2,593,831		$4,173,234		$16,881,886
SCHEDULE 48T											
Large General Service 1,000 kW and over-Primary-Combined											
Basic Charge											
<=3000 kW	130	$1,419.00	$184,857	$1,419.00	$184,857	$1,419.00	$184,857		$0		$0
>3000 kW	0	$1,707.00	$0	$1,707.00	$0	$1,707.00	$0		$0		$0
Total Basic Charges	130										
<=3000 kW variable	221,683	$0.53	$117,492	$0.61	$135,227	$0.61	$135,227		$0		$0
>3000 kW variable	0	$0.43	$0	$0.48	$0	$0.48	$0		$0		$0
All kW	178,076	$7.40	$1,317,766	$8.32	$1,481,596	$1.48	$262,804	$1.36	$241,571	$5.48	$977,222
Energy Charges											
All kWh	70,618,436	4.459 ¢	$3,148,876	1.508 ¢	$1,064,926		$0	0.983 ¢	$694,388	0.525 ¢	$370,538
Excess Kvar	17,311	$0.54	$9,348	$0.54	$9,348		$0	$0.11	$1,853	$0.43	$7,495
NPC-Base - All kWh	70,618,436			3.453 ¢	$2,438,455		$0		$0	3.453 ¢	$2,438,455
Total Rate - All kWh		4.459 ¢		4.961 ¢				0.983 ¢		3.978 ¢	
Subtotal	70,618,436		$4,778,339		$5,314,409		$582,888		$937,812		$3,793,709
Unbilled	(299,271)		(21,715)		($21,715)		($2,382)		($3,832)		($15,501)
Total	70,319,165		$4,756,624		$5,292,694		$580,506		$933,980		$3,778,208
SCHEDULE 48T											
Large General Service 30,000 kW and over-Primary Dedicated Facilities											
Basic Charge											
<=30000 kW	0		$0		$0		$0		$0		$0
>30000 kW	12	$2,528.00	$30,336	$2,747.00	$32,964	$2,747.00	$32,964		$0		$0
Total Basic Charges	12										
<=3000 kW variable	0		$0		$0		$0		$0		$0
>30000 kW variable	693,243	$0.23	$159,446	$0.27	$187,176	$0.27	$187,176		$0		$0
All kW	681,696	$7.35	$5,010,466	$8.25	$5,623,992	$1.17	$795,203	$1.40	$956,542	$5.68	$3,872,247
Energy Charges											
All kWh	455,274,000	4.430 ¢	$20,168,638	2.008 ¢	$9,141,902		$0	0.971 ¢	$4,419,110	1.037 ¢	$4,722,792
Excess Kvar	183,315	$0.53	$97,157	$0.53	$97,157		$0	$0.10	$19,246	$0.43	$77,911
NPC-Base - All kWh	455,274,000			2.892 ¢	$13,166,524		$0		$0	2.892 ¢	$13,166,524
Total Rate - All kWh		4.430 ¢		4.900 ¢				0.971 ¢		3.929 ¢	
Subtotal	455,274,000		$25,466,043		$28,249,715		$1,015,343		$5,394,898		$21,839,474
Unbilled	(7,292,369)		($525,379)		($525,379)		($18,883)		($100,332)		($406,163)
Total	447,981,631		$24,940,664		$27,724,336		$996,460		$5,294,565		$21,433,311

PACIFIC POWER & LIGHT COMPANY
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2013
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars	Distribution Price	Distribution Dollars	Transmission Price	Transmission Dollars	Generation Price	Generation Dollars
SCHEDULE 51											
Street Lighting Service Company-Owned											
High Pressure Sodium Vapor											
Per Lamp Charges											
5,800 Lumens	14,351	$8.46	$121,410	$8.84	$126,863	$5.17	$74,243	$0.72	$10,400	$2.95	$42,220
9,500 Lumens	17,710	$10.15	$179,753	$10.61	$187,899	$6.21	$109,963	$0.87	$15,403	$3.53	$62,533
9,500 Lumens-Decorative Seri	0	$32.24	$0	$33.70	$0	$19.72	$0	$2.76	$0	$11.22	$0
9,500 Lumens-Decorative Seri	0	$25.07	$0	$26.21	$0	$15.34	$0	$2.15	$0	$8.72	$0
16,000 Lumens	832	$12.97	$10,786	$13.56	$11,276	$7.94	$6,599	$1.11	$924	$4.51	$3,753
16,000-Lumens Decorative Se	0	$33.40	$0	$34.92	$0	$20.44	$0	$2.86	$0	$11.62	$0
16,000-Lumens Decorative Ser	0	$26.27	$0	$27.46	$0	$16.07	$0	$2.25	$0	$9.14	$0
22,000 Lumens	19,416	$14.81	$287,547	$15.48	$300,555	$9.06	$175,891	$1.27	$24,638	$5.15	$100,026
27,500 Lumens	1,587	$18.79	$29,816	$19.64	$31,165	$11.49	$18,238	$1.61	$2,555	$6.54	$10,372
50,000 Lumens	2,399	$24.80	$59,492	$25.93	$62,203	$15.17	$36,403	$2.13	$5,099	$8.63	$20,701
LED											
4,000 Lumens	0	$9.35	$0	$9.77	$0	$5.72	$0	$0.80	$0	$3.25	$0
6,200 Lumens	0	$11.79	$0	$12.33	$0	$7.22	$0	$1.01	$0	$4.10	$0
13,000 Lumens	0	$19.60	$0	$20.49	$0	$11.99	$0	$1.68	$0	$6.82	$0
16,800 Lumens	0	$24.73	$0	$25.85	$0	$15.13	$0	$2.12	$0	$8.60	$0
Metal Halide											
9,000 Lumens-Decorative Serie	0	$30.92	$0	$32.32	$0	$18.91	$0	$2.65	$0	$10.76	$0
9,000 Lumens-Decorative Serie	0	$25.79	$0	$26.96	$0	$15.78	$0	$2.21	$0	$8.97	$0
12,000 Lumens	0	$23.77	$0	$24.85	$0	$14.54	$0	$2.04	$0	$8.27	$0
12,000 Lumens-Decorative Ser	0	$34.74	$0	$36.32	$0	$21.26	$0	$2.98	$0	$12.08	$0
12,000 Lumens-Decorative Ser	0	$27.97	$0	$29.24	$0	$17.11	$0	$2.40	$0	$9.73	$0
19,500 Lumens	0	$27.49	$0	$28.74	$0	$16.82	$0	$2.36	$0	$9.56	$0
32,000 Lumens	0	$29.93	$0	$31.29	$0	$18.31	$0	$2.56	$0	$10.42	$0
Total Bills	1,956										
NPC-Base - All kWh *	3,532,348			0.000 ¢	$0		$0		$0	0.000 ¢	$0
Subtotal	3,532,348		$688,804		$719,961		$421,337		$59,019		$239,605
Unbilled	(345,752)		($67,823)		($67,823)		($39,692)		($5,560)		($22,572)
Total	3,186,596		$620,981		$652,138		$381,645		$53,459		$217,033
*Included in Generation Price											
SCHEDULE 52											
Company-Owned Street Lighting Service											
Operation, Maintenance, Depreciation & Fixed Costs			$19,992		$19,992		$19,992				
Dusk to Dawn kWh	219,861	7.814 ¢	$17,180	6.270 ¢	$13,785	1.245 ¢	$2,738	1.448 ¢	$3,184	3.577 ¢	$7,863
Dusk to Midnight kWh	0	8.744 ¢	$0	7.016 ¢	$0	1.394 ¢	$0	1.620 ¢	$0	4.002 ¢	$0
Total Bills	180										
NPC-Base - All kWh	219,861			2.303 ¢	$5,063		$0		$0	2.303 ¢	$5,063
Total Energy Rate per kWh		7.814 ¢		8.573 ¢		1.245 ¢		1.448 ¢		5.880 ¢	
Subtotal	219,861		$37,172		$38,840		$22,730		$3,184		$12,926
Unbilled	(21,520)		($3,660)		($3,660)		($2,142)		($300)		($1,218)
Total	198,341		$33,512		$35,180		$20,588		$2,884		$11,708
SCHEDULE 53											
Customer-Owned Street Lighting Service - Grand Combined											
Operation, Maintenance, Depreciation & Fixed Costs			$2,258		$2,258		$2,258		$0		$0
Non-Listed Lumen-Energy Only	2,344,657		$160,210		$167,572		$49,845		$6,982		$28,334
Listed Lumen-Energy Only	2,268,877		$155,024		$162,003		$93,871		$13,465		$54,679
Total Bills	2,605										
NPC-Base - All kWh *	4,613,534			0.000 ¢	$0		$0		$0	0.000 ¢	$0
Subtotal	4,613,534		$317,492		$331,834		$194,196		$27,202		$110,435
Unbilled	(451,581)		($31,263)		($31,263)		($18,296)		($2,563)		($10,404)
Total	4,161,954		$286,229		$300,571		$175,901		$24,639		$100,031
*Included in Generation Price											

PACIFIC POWER & LIGHT COMPANY
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2013
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars	Distribution Price	Distribution Dollars	Transmission Price	Transmission Dollars	Generation Price	Generation Dollars
SCHEDULE 53F											
Customer-Owned Street Lighting Service											
Operation, Maintenance, Depreciation & Fixed Costs			$2,258		$2,258		$2,258				
High Pressure Sodium Vapor											
5,800 Lumens-Energy Only	4,296	$2.12	$9,108	$2.22	$9,537	$1.29	$5,526	$0.18	$793	$0.75	$3,219
9,500 Lumens-Energy Only	8,148	$3.00	$24,444	$3.13	$25,503	$1.81	$14,778	$0.26	$2,120	$1.06	$8,608
16,000 Lumens-Energy Only	80	$4.36	$349	$4.56	$365	$2.64	$212	$0.38	$30	$1.54	$123
22,000 Lumens-Energy Only	11,687	$5.81	$67,902	$6.07	$70,940	$3.52	$41,106	$0.50	$5,896	$2.05	$23,943
27,500 Lumens-Energy Only	4,356	$7.86	$34,238	$8.22	$35,806	$4.76	$20,748	$0.68	$2,976	$2.78	$12,085
50,000 Lumens-Energy Only	1,578	$12.03	$18,983	$12.58	$19,851	$7.29	$11,503	$1.05	$1,650	$4.24	$6,700
Metal Halide											
9,000 Lumens-Energy Only	0	$2.67	$0	$2.80	$0	$1.62	$0	$0.23	$0	$0.95	$0
12,000 Lumens-Energy Only	0	$4.65	$0	$4.86	$0	$2.82	$0	$0.40	$0	$1.64	$0
19,500 Lumens-Energy Only	0	$6.43	$0	$6.73	$0	$3.90	$0	$0.56	$0	$2.27	$0
32,000 Lumens-Energy Only	0	$10.18	$0	$10.65	$0	$6.17	$0	$0.89	$0	$3.59	$0
107,800 Lumens-Energy Only	0	$24.19	$0	$25.30	$0	$14.66	$0	$2.10	$0	$8.54	$0
Non-Listed Lumen-Energy Only	1,191,736	6.833 ¢	$81,431	7.147 ¢	$85,173	4.183 ¢	$49,845	0.586 ¢	$6,982	2.378 ¢	$28,334
Listed Lumen-Energy Only-above	2,268,877	0 ¢	$0	0 ¢	$0	0 ¢	$0	0 ¢	$0	0 ¢	$0
Total Bills	1,346										
NPC-Base - All kWh *	3,460,613			0.000 ¢	$0	¢	$0	¢	$0	0.000 ¢	$0
Total Energy Rate		6.833 ¢		7.147 ¢		4.183 ¢		0.586 ¢		2.378 ¢	
Subtotal	3,460,613		$238,713		$249,435		$145,975		$20,447		$83,013
Unbilled	(338,731)		($23,506)		($23,506)		($13,756)		($1,927)		($7,823)
Total	3,121,883		$215,207		$225,929		$132,219		$18,520		$75,190
*Included in Generation Price											
											$225,929
SCHEDULE 53M											($0)
Customer-Owned Street Lighting Service											
Operation, Maintenance, Depreciation & Fixed Costs			$0		$0		$0		$0		$0
Option A (Co. O&M) kWh	0	6.833 ¢	$0	7.147 ¢	$0	4.183 ¢	$48,222	0.586 ¢	$6,755	2.378 ¢	$27,423
Option B (Cust. O&M) kWh	1,152,921	6.833 ¢	$78,779	7.147 ¢	$82,399	4.183 ¢	$0	0.586 ¢	$0	2.378 ¢	$0
Total Bills	1,259										
NPC-Base - All kWh *	1,152,921			0.000 ¢	$0		$0		$0	0.000 ¢	$0
Subtotal	1,152,921		$78,779		$82,399		$48,222		$6,755		$27,423
Unbilled	(112,850)		($7,757)		($7,757)		($4,540)		($636)		($2,582)
Total	1,040,071		$71,022		$74,642		$43,682		$6,119		$24,841
*Included in Generation Price											
SCHEDULE 54											
Recreational Field Lighting											
Basic Charge 1 Phase	178	$3.75	$668	$3.75	$668	$3.75	$668		$0		$0
Basic Charge 3 Phase	182	$6.75	$1,227	$6.75	$1,227	$6.75	$1,227		$0		$0
Total Bills	360										
All kWh	295,386	8.111 ¢	$23,959	6.242 ¢	$18,438	4.735 ¢	$13,986	0.753 ¢	$2,224	0.754 ¢	$2,228
NPC-Base - All kWh	295,386			2.303 ¢	$6,803		$0		$0	2.303 ¢	$6,803
Total Energy Rate per kWh		8.111 ¢		8.545 ¢		4.735 ¢		0.753 ¢		3.057 ¢	
Subtotal	295,386		$25,854		$27,136		$15,881		$2,224		$9,031
Unbilled	(836)		($64)		($64)		($37)		($5)		($21)
Total	294,550		$25,790		$27,072		$15,843		$2,219		$9,010

PACIFIC POWER & LIGHT COMPANY
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2013
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars	Distribution Price	Distribution Dollars	Transmission Price	Transmission Dollars	Generation Price	Generation Dollars
SCHEDULE 57											
Mercury Vapor Street Lighting Service											
Overhead System on Wood Poles											
Horizontal Lamp Charges											
7,000 Lumens	13,342	$9.75	$130,084	$10.19	$135,955	$5.96	$79,564	$0.84	$11,145	$3.39	$45,246
21,000 Lumens	1,917	$17.85	$34,220	$18.66	$35,773	$10.92	$20,935	$1.53	$2,932	$6.21	$11,905
55,000 Lumens	0	$36.10	$0	$37.73	$0	$22.08	$0	$3.09	$0	$12.56	$0
Vertical Lamp Charges											
7,000 Lumens	4,255	$9.15	$38,936	$9.56	$40,680	$5.59	$23,807	$0.78	$3,335	$3.19	$13,538
21,000 Lumens	0	$16.65	$0	$17.40	$0	$10.18	$0	$1.43	$0	$5.79	$0
Overhead System on Metal Poles											
Horizontal Lamp Charges											
7,000 Lumens	479	$12.74	$6,098	$13.32	$6,376	$7.80	$3,731	$1.09	$523	$4.43	$2,122
21,000 Lumens	396	$21.39	$8,470	$22.36	$8,855	$13.09	$5,182	$1.83	$726	$7.44	$2,947
55,000 Lumens	0	$39.67	$0	$41.47	$0	$24.27	$0	$3.40	$0	$13.80	$0
Vertical Lamp Charges											
7,000 Lumens	0	$12.06	$0	$12.61	$0	$7.38	$0	$1.03	$0	$4.20	$0
21,000 Lumens	0	$20.22	$0	$21.13	$0	$12.37	$0	$1.73	$0	$7.03	$0
Underground System											
Horizontal Lamp Charges											
7,000 Lumens	0	$12.73	$0	$13.31	$0	$7.79	$0	$1.09	$0	$4.43	$0
21,000 Lumens	0	$20.70	$0	$21.64	$0	$12.66	$0	$1.77	$0	$7.21	$0
55,000 Lumens	0	$38.99	$0	$40.75	$0	$23.85	$0	$3.34	$0	$13.56	$0
Vertical Lamp Charges											
7,000 Lumens	0	$12.06	$0	$12.61	$0	$7.38	$0	$1.03	$0	$4.20	$0
21,000 Lumens	0	$19.53	$0	$20.41	$0	$11.94	$0	$1.67	$0	$6.80	$0
Post 1977 System											
7,000 Lumens	420	$10.19	$4,280	$10.65	$4,473	$6.23	$2,618	$0.87	$367	$3.55	$1,489
21,000 Lumens	789	$17.84	$14,076	$18.65	$14,715	$10.91	$8,612	$1.53	$1,206	$6.21	$4,897
55,000 Lumens	0	$38.11	$0	$39.83	$0	$23.31	$0	$3.27	$0	$13.25	$0
Contract											
21,000 Lumens	0	$36.57	$0	$38.22	$0	$22.37	$0	$3.13	$0	$12.72	$0
Total Bills	407										
NPC-Base - All kWh *	1,932,403			0.000 ¢	$0		$0		$0	0.000 ¢	$0
Subtotal	1,932,403		$236,164		$246,827		$144,449		$20,234		$82,145
Unbilled	(189,147)		($23,254)		($23,254)		($13,609)		($1,906)		($7,739)
Total	1,743,256		$212,910		$223,573		$130,840		$18,327		$74,406
*Included in Generation Price											
Washington TOTALS	4,010,161,433		$320,954,140		$352,892,908		$66,827,270		$56,646,520		$229,419,118
AGA			$651,518		$651,518		$651,518				
Washington TOTALS with AGA	**4,010,161,433**		**$ 321,605,658**		**$ 353,544,427**		**$ 67,478,789**		**$ 56,646,520**		**$ 229,419,118**

Summary fopr Unbundling

PacifiCorp
Cost Of Service By Rate Schedule
State of Washington
12 Months Ending December 2013
WCA Method - (100 Summer, 100 Winter Hours) - 43%D / 57%E
7.76% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	16	Residential	140,088,119	3.22%	0.59	163,792,081	98,351,484	24,283,866	32,853,370	5,749,833	2,553,529	23,703,963	16.92%
2	24	Small General Service	48,473,096	9.85%	1.82	47,734,808	30,746,707	7,578,072	7,789,821	773,584	846,625	(738,288)	-1.52%
3	36	Large General Service <1,000 kW	66,810,176	7.15%	1.32	70,232,276	49,015,377	12,119,267	7,826,236	(113)	1,271,510	3,422,100	5.12%
4	48T	Large General Service >1,000 kW	26,035,610	6.18%	1.14	28,011,710	19,996,257	4,943,112	2,535,201	29,198	507,942	1,976,100	7.59%
	47T		0			0						0	
5	48T	Dedicated Facilities	24,940,664	3.60%	0.67	28,476,719	22,014,968	5,438,249	482,059	14,793	526,650	3,536,055	14.18%
6	40	Agricultural Pumping Service	12,666,289	9.01%	1.66	12,730,015	8,069,740	1,982,127	2,322,143	132,753	223,252	63,726	0.50%
7	15,52,54,57	Street Lighting	1,648,057	9.82%	1.81	1,623,358	540,259	133,075	831,391	98,071	20,562	(24,698)	-1.50%
8		Total Washington Jurisdiction	320,662,012	5.41%	1.00	352,600,969	228,734,791	56,477,767	54,640,221	6,798,118	5,950,071	31,938,957	9.96%

		B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	**Generation Cost of Service**	**Transmission Cost of Service**	**Distribution Cost of Service**	**Retail Cost of Service**	**Misc Cost of Service**	**Increase (Decrease) to = ROR**	Percentage Change from Current Revenues
1	16	Residential	140,088,119	3.22%	0.59	163,792,081	**60.05%**	**14.83%**	**20.06%**	**3.51%**	**1.56%**	**100.00%**	16.92%
2	24	Small General Service	48,473,096	9.85%	1.82	47,734,808	**64.41%**	**15.88%**	**16.32%**	**1.62%**	**1.77%**	**100.00%**	-1.52%
3	36	Large General Service <1,000 kW	66,810,176	7.15%	1.32	70,232,276	**69.79%**	**17.26%**	**11.14%**	**0.00%**	**1.81%**	**100.00%**	5.12%
4	48T	Large General Service >1,000 kW	26,035,610	6.18%	1.14	28,011,710	**71.39%**	**17.65%**	**9.05%**	**0.10%**	**1.81%**	**100.00%**	7.59%
	47T		0	0.00%		0	**71.39%**	**17.65%**	**9.05%**	**0.10%**	**1.81%**	**100.00%**	
5	48T	Dedicated Facilities	24,940,664	3.60%	0.67	28,476,719	**77.31%**	**19.10%**	**1.69%**	**0.05%**	**1.85%**	**100.00%**	14.18%
6	40	Agricultural Pumping Service	12,666,289	9.01%	1.66	12,730,015	**63.39%**	**15.57%**	**18.24%**	**1.04%**	**1.75%**	**100.00%**	0.50%
7	15,52,54,57	Street Lighting	1,648,057	9.82%	1.81	1,623,358	**33.28%**	**8.20%**	**51.21%**	**6.04%**	**1.27%**	**100.00%**	-1.50%
8		Total Washington Jurisdiction	320,662,012	5.41%	1.00	352,600,969							9.96%

Source:Exhibit No.__(JRS-2).

Pacific Power & Light Company
Washington Low Income
Schedule 91 Surcharge Rates Proposal

Number of customers served	5,428							
Increase in average dollar subsidy/ client	22.3%		**Current**	**Proposed**				
	$ 70.00		Program *	Program with 23.397% Increase	Change	Estimated Monthly Surcharge Increase	Customers	Estimated Annual Proposed Revenues
	Admin Costs current	Admin Costs proposed						
Annual Revenues Collections			$1,992,908	$2,471,570	$478,662			
Administrative Costs ($/cust)	$ 67.50	$ 70.00	$318,600	$330,400	$11,800			
Available for subsidy			$1,674,308	$2,141,170	$466,862			
Schedule 91 Charges	Sch.	15	$0.13	$0.16		$0.03	2,532	$4,861
	Sch.	16/18(#2)	$0.74	$0.90		$0.16	100,195	$1,082,106
	Sch.	24	$1.56	$1.93		$0.37	18,788	$435,142
	Sch.	33	$37.89	$46.88		$8.99	0	$0
	Sch.	36	$37.89	$46.88		$8.99	1,054	$592,890
	Sch.	40	$15.65	$19.38	(#1)	$3.73	5,247	$101,687
	Sch.	47T	$257.50	$318.46		$60.96	1	$3,822
	Sch.	48T	$257.50	$318.46		$60.96	62	$236,982
	Sch.	51	$2.15	$2.67		$0.52	163	$5,223
	Sch.	52	$2.15	$2.67		$0.52	15	$481
	Sch.	53	$2.15	$2.67		$0.52	217	$6,955
	Sch.	54	$0.75	$0.93		$0.18	30	$335
	Sch.	57	$2.15	$2.67		$0.52	34	$1,087
							128,338	$2,471,570
Number of Qualifying Customers			5,192	5,428	236			$13
								Rev excess/(short)

(#1) Annual Amount
(#2) Reduced number of customers by change in new Schedule 17 customers

Cost per Qualifying Customer	current	proposed	Increase /Customer	% Increase /Customer
Average Credit per Customer - (Credit/Customers)	$322.48	$394.47	$71.99	22.32%
Agency Charge per Qualifying Customer	$67.50	$70.00		
Average Cost per Qualifying Customer	$389.98	$464.47		
Annual Revenues - (Average Cost x Customers)	$1,992,908	$2,471,570		
Annual Credits to Customers	$1,674,316	$2,141,157		

Proposed Credit Increase		
Current Credit per Participant plus 18.6%	122%	$394.47
total participants	5,428	
Total benefits		$2,141,157
Admin Expense		$330,400
Total Program cost		**$2,471,557**

Pacific Power & Light Company
Washington Low Income
Energy Rate Credit Proposal

% of Federal Poverty Level (FPL)	Estimated Customers	Total Credit	Discount/ Customer	Rate ¢/kWh	Estimated kWh
0-75%	2,313	$1,220,767	$527.89	**8.359**	14,604,228
76-100%	1,767	$618,940	$350.33	**5.623**	11,007,300
101-150%	1,349	$301,536	$223.57	**3.514**	8,580,991
Total	5,428	$2,141,244	$394.48	**6.262**	34,192,519

Exhibit No. JRS-18
Docket UE-140762 *et al.*
Witness: Joelle R. Steward

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF JOELLE R. STEWARD

Monthly Billing Comparison

November 2014

Pacific Power & Light Company
Monthly Billing Comparison
Schedule 16 - Residential Service

	Monthly Basic Charge			Monthly Energy Charge [1]				Total Change	
						Change			
kWh	Present	Proposed	Change	Present	Proposed	$	%	$	%
50	$7.75	$14.00	$6.25	$3.77	$4.04	$0.27	7.16%	$6.52	56.60%
100	$7.75	$14.00	$6.25	$6.80	$7.35	$0.55	8.09%	$6.80	46.74%
150	$7.75	$14.00	$6.25	$9.83	$10.65	$0.82	8.34%	$7.07	40.22%
200	$7.75	$14.00	$6.25	$12.86	$13.95	$1.09	8.48%	$7.34	35.61%
300	$7.75	$14.00	$6.25	$18.92	$20.56	$1.64	8.67%	$7.89	29.58%
400	$7.75	$14.00	$6.25	$24.98	$27.16	$2.18	8.73%	$8.43	25.76%
500	$7.75	$14.00	$6.25	$31.04	$33.77	$2.73	8.80%	$8.98	23.15%
600	$7.75	$14.00	$6.25	$37.10	$40.37	$3.27	8.81%	$9.52	21.23%
700	$7.75	$14.00	$6.25	$46.78	$50.82	$4.04	8.64%	$10.29	18.87%
800	$7.75	$14.00	$6.25	$56.46	$61.27	$4.81	8.52%	$11.06	17.22%
900	$7.75	$14.00	$6.25	$66.13	$71.71	$5.58	8.44%	$11.83	16.01%
1,000	$7.75	$14.00	$6.25	$75.81	$82.16	$6.35	8.38%	$12.60	15.08%
1,100	$7.75	$14.00	$6.25	$85.49	$92.61	$7.12	8.33%	$13.37	14.34%
1,200	$7.75	$14.00	$6.25	$95.17	$103.06	$7.89	8.29%	$14.14	13.74%
1,300 *	$7.75	$14.00	$6.25	$104.85	$113.51	$8.66	8.26%	$14.91	13.24%
1,400	$7.75	$14.00	$6.25	$114.52	$123.95	$9.43	8.23%	$15.68	12.82%
1,500	$7.75	$14.00	$6.25	$124.20	$134.40	$10.20	8.21%	$16.45	12.47%
1,600	$7.75	$14.00	$6.25	$133.88	$144.85	$10.97	8.19%	$17.22	12.16%
2,000	$7.75	$14.00	$6.25	$172.59	$186.64	$14.05	8.14%	$20.30	11.26%
2,600	$7.75	$14.00	$6.25	$230.66	$249.33	$18.67	8.09%	$24.92	10.45%

Notes:
* Average Washington Customer
[1] Includes SBC Charge, Low Income Charge, Deferral Surcharge and BPA Credit.

Pacific Power & Light Company
Monthly Billing Comparison
Schedule 17 - Residential Service

	Monthly Basic Charge			Monthly Energy Charge [1]				Total Change	
						Change			
kWh	Present	Proposed	Change	Present	Proposed	$	%	$	%
50	$7.75	$8.75	$1.00	$3.03	$3.30	$0.27	8.91%	$1.27	11.78%
100	$7.75	$8.75	$1.00	$6.06	$6.61	$0.55	9.08%	$1.55	11.22%
150	$7.75	$8.75	$1.00	$9.09	$9.91	$0.82	9.02%	$1.82	10.81%
200	$7.75	$8.75	$1.00	$12.12	$13.21	$1.09	8.99%	$2.09	10.52%
300	$7.75	$8.75	$1.00	$18.18	$19.82	$1.64	9.02%	$2.64	10.18%
400	$7.75	$8.75	$1.00	$24.24	$26.42	$2.18	8.99%	$3.18	9.94%
500	$7.75	$8.75	$1.00	$30.30	$33.03	$2.73	9.01%	$3.73	9.80%
600	$7.75	$8.75	$1.00	$36.36	$39.63	$3.27	8.99%	$4.27	9.68%
700	$7.75	$8.75	$1.00	$39.64	$41.72	$2.08	5.25%	$3.08	6.50%
800	$7.75	$8.75	$1.00	$42.92	$43.81	$0.89	2.07%	$1.89	3.73%
900	$7.75	$8.75	$1.00	$46.21	$45.90	($0.31)	-0.67%	$0.69	1.28%
1,000	$7.75	$8.75	$1.00	$49.49	$47.99	($1.50)	-3.03%	($0.50)	-0.87%
1,100	$7.75	$8.75	$1.00	$52.77	$50.08	($2.69)	-5.10%	($1.69)	-2.79%
1,200	$7.75	$8.75	$1.00	$56.05	$52.16	($3.89)	-6.94%	($2.89)	-4.53%
1,300	$7.75	$8.75	$1.00	$59.33	$54.25	($5.08)	-8.56%	($4.08)	-6.08%
1,400	$7.75	$8.75	$1.00	$62.62	$56.34	($6.28)	-10.03%	($5.28)	-7.50%
1,500	$7.75	$8.75	$1.00	$65.90	$58.43	($7.47)	-11.34%	($6.47)	-8.78%
1,700 *	$7.75	$8.75	$1.00	$72.46	$62.61	($9.85)	-13.59%	($8.85)	-11.03%
2,000	$7.75	$8.75	$1.00	$82.31	$68.88	($13.43)	-16.32%	($12.43)	-13.80%
3,000	$7.75	$8.75	$1.00	$115.13	$89.77	($25.36)	-22.03%	($24.36)	-19.82%

Notes:
* Schedule 17 Washington Customer Average Monthly Winter Usage
[1] Includes SBC Charge, Deferral Surcharge, BPA Credit and Low Income Credit @0-75% FPL.

Pacific Power & Light Company
Monthly Billing Comparison
Schedule 24 - Small General Service

kW Load Size/ Demand	kWh	Monthly Billing * Present Price Schedule 24 Single Phase	Present Price Schedule 24 Three Phase	Proposed Price Schedule 24 Single Phase	Proposed Price Schedule 24 Three Phase	Percent Difference Single Phase	Percent Difference Three Phase
15	5,000	$414	$419	$440	$445	6.29%	6.40%
	7,500	$600	$605	$638	$643	6.28%	6.36%
	10,000	$776	$781	$825	$830	6.31%	6.37%
25	3,750	$367	$371	$389	$394	6.17%	6.29%
	5,000	$460	$464	$488	$493	6.19%	6.29%
	10,000	$822	$826	$873	$878	6.25%	6.31%
50	7,500	$759	$763	$805	$810	6.08%	6.14%
	10,000	$935	$939	$992	$997	6.14%	6.19%
	20,000	$1,580	$1,584	$1,680	$1,685	6.31%	6.34%
75	25,000	$2,015	$2,020	$2,142	$2,147	6.30%	6.32%
	37,500	$2,822	$2,826	$3,002	$3,007	6.38%	6.39%
	50,000	$3,628	$3,632	$3,861	$3,866	6.42%	6.43%
100	25,000	$2,129	$2,133	$2,262	$2,267	6.25%	6.27%
	37,500	$2,935	$2,939	$3,121	$3,126	6.34%	6.35%
	50,000	$3,741	$3,745	$3,980	$3,985	6.39%	6.40%

Notes:

* Includes SBC Charge, Deferral Surcharge and Low Income Charge.

Pacific Power & Light Company
Monthly Billing Comparison
Schedule 36 - Large General Service < 1,000 kW

kW Load Size/ Demand	kWh	Monthly Billing * Present Schedule 36	Monthly Billing * Proposed Schedule 36	Percent Difference
100	25,000	$2,236	$2,502	11.87%
	37,500	$2,970	$3,311	11.47%
	50,000	$3,656	$4,068	11.27%
200	60,000	$4,845	$5,466	12.83%
	100,000	$7,004	$7,851	12.10%
	140,000	$9,162	$10,235	11.71%
300	90,000	$7,106	$8,031	13.01%
	150,000	$10,344	$11,607	12.21%
	210,000	$13,582	$15,184	11.79%
400	120,000	$9,339	$10,555	13.02%
	200,000	$13,657	$15,324	12.21%
	280,000	$17,974	$20,093	11.79%
600	180,000	$13,799	$15,616	13.16%
	300,000	$20,276	$22,769	12.30%
	420,000	$26,752	$29,922	11.85%
800	240,000	$18,259	$20,676	13.24%
	400,000	$26,895	$30,214	12.34%
	560,000	$35,530	$39,751	11.88%
1000	300,000	$22,720	$25,737	13.28%
	500,000	$33,514	$37,659	12.37%
	700,000	$44,308	$49,581	11.90%

Notes:

* Includes SBC Charge, Deferral Surcharge and Low Income Charge.

Pacific Power & Light Company
Billing Comparison
Schedule 40 - Agricultural Pumping Service

		Present Price Schedule 40 *		Proposed Price Schedule 40 *		Percent Difference	
kW Load Size/ Demand	kWh	Present Schedule 40 ** Monthly Bill	Annual Load Size Charge	Proposed Schedule 40 ** Monthly Bill	Annual Load Size Charge	Monthly ** Bill	Annual Load Size Charge
Single Phase							
10	2,000	$133	$267	$143	$280	7.32%	4.65%
	3,000	$200	$267	$215	$280	7.32%	4.65%
	5,000	$333	$267	$358	$280	7.32%	4.65%
Three Phase							
20	4,000	$267	$519	$286	$544	7.32%	4.79%
	6,000	$400	$519	$429	$544	7.32%	4.79%
	10,000	$666	$519	$715	$544	7.32%	4.79%
100	20,000	$1,333	$2,125	$1,430	$2,231	7.32%	4.95%
	30,000	$1,999	$2,125	$2,145	$2,231	7.32%	4.95%
	50,000	$3,332	$2,125	$3,576	$2,231	7.32%	4.95%
300	60,000	$3,998	$5,631	$4,291	$5,911	7.32%	4.97%
	90,000	$5,997	$5,631	$6,436	$5,911	7.32%	4.97%
	150,000	$9,995	$5,631	$10,727	$5,911	7.32%	4.97%

Notes:
* Includes SBC Charge BPA Credit, Deferral Surcharge and Low Income charge.
** Does not include November Load Size Charge.

Pacific Power & Light Company
Monthly Billing Comparison
Schedule 48T - Large General Service - Secondary
1,000 kW and Over

kW Load Size/ Demand	kWh	Monthly Billing * Present Price Schedule 48T	Monthly Billing * Proposed Price Schedule 48T	Percent Difference
1,000	300,000	$24,378	$27,279	11.90%
	500,000	$33,794	$37,929	12.24%
	700,000	$43,210	$48,579	12.43%
2,000	600,000	$47,112	$52,914	12.32%
	1,000,000	$65,944	$74,214	12.54%
	1,400,000	$84,776	$95,514	12.67%
4,000	1,200,000	$92,469	$104,033	12.51%
	2,000,000	$130,133	$146,633	12.68%
	2,800,000	$167,797	$189,233	12.77%
6,000	1,800,000	$137,737	$155,083	12.59%
	3,000,000	$194,233	$218,983	12.74%
	4,200,000	$250,729	$282,883	12.82%

Notes:

* Includes SBC Charge, Deferral Surcharge and Low Income Charge.

Pacific Power & Light Company
Monthly Billing Comparison
Schedule 48T - Large General Service - Primary
1,000 kW and Over

kW Load Size/ Demand	kWh	Monthly Billing * Present Price Schedule 48T	Monthly Billing * Proposed Price Schedule 48T	Percent Difference
1,000	300,000	$23,566	$26,411	12.07%
	500,000	$32,872	$36,947	12.40%
	700,000	$42,178	$47,483	12.58%
2,000	600,000	$45,455	$51,145	12.52%
	1,000,000	$64,067	$72,217	12.72%
	1,400,000	$82,679	$93,289	12.83%
4,000	1,200,000	$89,121	$100,381	12.63%
	2,000,000	$126,345	$142,525	12.81%
	2,800,000	$163,569	$184,669	12.90%
6,000	1,800,000	$132,699	$149,589	12.73%
	3,000,000	$188,535	$212,805	12.87%
	4,200,000	$244,371	$276,021	12.95%

Notes:
* Includes SBC Charge, Deferral Surcharge and Low Income Charge.

Pacific Power & Light Company
Monthly Billing Comparison
Schedule 48T - Large General Service - Primary
30,000 kW and Over
Served by Dedicated Facilities

kW Load Size/ Demand	kWh	Monthly Billing * Present Price Schedule 48T	Monthly Billing * Proposed Price Schedule 48T	Percent Difference
30,000	9,000,000	$646,346	$727,235	12.51%
	15,000,000	$923,786	$1,039,655	12.54%
	21,000,000	$1,201,226	$1,352,075	12.56%
40,000	12,000,000	$860,866	$968,645	12.52%
	20,000,000	$1,230,786	$1,385,205	12.55%
	28,000,000	$1,600,706	$1,801,765	12.56%
50,000	15,000,000	$1,075,386	$1,210,055	12.52%
	25,000,000	$1,537,786	$1,730,755	12.55%
	35,000,000	$2,000,186	$2,251,455	12.56%
60,000	18,000,000	$1,289,906	$1,451,465	12.52%
	30,000,000	$1,844,786	$2,076,305	12.55%
	42,000,000	$2,399,666	$2,701,145	12.56%

Notes:

* Includes SBC Charge, Deferral Surcharge and Low Income Charge.

Exhibit No. JRS-19
Docket UE-140762 *et al.*
Witness: Joelle R. Steward

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF JOELLE R. STEWARD

Residential Basic Charge Calculation

November 2014

Pacific Power & Light Company
State of Washington
12 Months Ended December 2013
Residential Customer Charge Calculation Details

			Company **Fixed Costs Calculation**		**Staff** **Staff Basic Charge Calculation**	
Line	Description	Source	Rate Case Cost Components	Average Cost per Customer	Rate Case Cost Components	Average Cost per Customer
1	Retail	Exhibit No.___(JRS-15), p. 8, line 99	$5,749,833	$4.60	$5,749,833	$4.60
2	Distribution - Poles & Conductors	Exhibit No.___(JRS-15), p. 8, line 75	$16,985,477	$13.50	$0	$0.00
3	Distribution - Meters	Exhibit No.___(JRS-15), p. 8, line 87	$1,713,997	$1.40	$1,713,997	$1.40
4	Distribution - Service Lines	Exhibit No.___(JRS-15), p. 8, line 93	$3,987,839	$3.20	$3,987,839	$3.20
5	Distribution - Transformers	Exhibit No.___(JRS-15), p. 8, line 81	$6,162,196	$4.90	$6,162,196	$4.90
6	Total Retail & Distribution Costs		$34,599,342	$28.00	$17,613,865	$14.10
7	Average Number of Customers	Exhibit No.___(JRS-15), p. 7, line 17	104,635		104,635	
8	**Proposed Basic Charge**			**$14.00**		**$14.10**

Exhibit No. JRS-20
Docket UE-140762 *et al.*
Witness: Joelle R. Steward

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

<table>
<tr><td>WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY,

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PACIFIC POWER & LIGHT COMPANY,

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For an Order Approving Deferral of Costs Related to Declining Hydro Generation.</td><td>DOCKET UE-140094 (consolidated)</td></tr>
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PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF JOELLE R. STEWARD

Survey of Monthly Basic Charges in Washington

November 2014

Company Survey of Monthly Basic Charges in Washington* For Single-Phase Residential Service			
Avista Corporation	$ 8.00	Klickitat County PUD	$ 17.58
Benton County PUD	$ 11.05	Kootenai Electric Cooperative Inc	$ 19.50
Blaine City Light	$ 5.50	Lakeview Light & Power	$ 18.50
Centralia City Light	$ 12.52	Lewis County PUD**	$ 16.50
Chelan County PUD	$ 7.70	Mason County PUD #1	$ 23.66
Cheney Power	$ 8.35	Mason County PUD #3**	$ 24.00
City of Ellensburg**	$ 15.37	Modern Electric Water Company (Spokane Valley)	$ 7.75
City of McCleary	$ 7.05	Nespelem Valley Electric Cooperative	$ 17.00
City of Richland	$ 12.25	Northern Lights, Inc.	$ 25.00
City of Sumas	$ 5.00	Okanogan PUD	$ 35.00
Clallam County PUD**	$ 23.28	Orcas Power and Light	$ 28.60
Clark County PUD	$ 12.00	Pacific County PUD	$ 13.00
Clearwater Power	$ 21.75	Parkland Light & Power	$ 14.00
Columbia REA	$ 17.50	Pend Oreille PUD	$ 24.50
Cowlitz County PUD	$ 17.00	Port Angeles City Light	$ 16.77
Douglas County PUD**	$ 9.99	Puget Sound Energy	$ 7.87
Elmhurst Power & Light Co	$ 14.00	Seattle City Light**	$ 4.82
Ferry County PUD	$ 17.00	Skamania PUD	$ 13.77
Franklin County PUD	$ 22.09	Tacoma Power	$ 5.50
Grant County PUD**	$ 13.80	Tanner Electric Cooperative	$ 19.50
Grays Harbor County PUD	$ 39.55	Town of Eatonville	$ 20.27
Inland Power & Light	$ 19.23	Town of Steilacoom	$ 15.60
Jefferson County PUD	$ 7.49	Vera Water & Power	$ 5.50
		Average of customer charges:	**$15.69**
		Number of utilities in survey:	**46**

*Source: Utility List from WA State Dept of Labor & Industries as of 10/17/2014

**Based on daily basic charge x 30 days

Exhibit No. JRS-21
Docket UE-140762 *et al.*
Witness: Joelle R. Steward

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

<table>
<tr><td>WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY,

Respondent.</td><td>DOCKETS UE-140762 and UE-140617 (consolidated)</td></tr>
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For an Order Approving Deferral of Costs Related to Declining Hydro Generation.</td><td>DOCKET UE-140094 (consolidated)</td></tr>
</table>

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF JOELLE R. STEWARD

Elasticity Analysis for Proposed Rate Design

November 2014

Elasticity Analysis for Proposed Rate Designs

Short-run Elasticity	0.079
Long-run Elasticity	0.161

Staff Proposal

Monthly Usage (kWh)	Number of Bills	Total Usage (kWh)	Average Usage	Proposed Increase	Short-run reduction in monthly usage, per bill (kWh)	Total first-year reduction, group (MWh)	Long-run reduction in monthly usage, per customer (kWh)	Total long-run annual reduction, group (MWh)
0-100	26,558	1,355,218	51	39.6%	1.60	42.39	3.25	86.39
101-200	24,633	4,289,444	174	28.8%	3.96	97.48	8.06	198.67
201-300	34,463	9,354,042	271	23.0%	4.94	170.22	10.07	346.91
301-400	47,960	17,473,607	364	19.5%	5.61	268.99	11.43	548.20
401-500	61,206	28,195,489	461	17.1%	6.21	380.30	12.66	775.03
501-600	72,717	40,575,539	558	15.3%	6.76	491.26	13.77	1,001.18
601-700	79,030	51,815,040	656	6.5%	3.35	264.84	6.83	539.74
701-800	80,966	61,093,974	755	0.3%	0.18	14.80	0.37	30.16
801-850	40,276	33,367,002	828	-0.2%	(0.12)	(4.76)	(0.24)	(9.70)
Total	467,811	247,519,355				1,726		3,517
851-900	39,639	34,828,725	879	-0.6%	(0.42)	(16.61)	(0.85)	(33.84)
901-1000	75,777	72,198,434	953	-1.3%	(0.98)	(74.23)	(2.00)	(151.28)
1001-1100	70,436	74,101,384	1,052	-1.9%	(1.54)	(108.51)	(3.14)	(221.15)
1101-1200	64,942	74,808,788	1,152	-2.3%	(2.09)	(136.02)	(4.27)	(277.20)
1201-1300	58,345	73,039,372	1,252	-2.7%	(2.64)	(154.17)	(5.39)	(314.20)
1301-1400	52,324	70,687,521	1,351	-3.0%	(3.18)	(166.61)	(6.49)	(339.54)
1401-1500	46,872	67,998,849	1,451	-3.2%	(3.72)	(174.54)	(7.59)	(355.71)
1501-1600	41,594	64,488,790	1,550	-3.5%	(4.26)	(177.21)	(8.68)	(361.15)
1601-1700	36,878	60,854,643	1,650	-3.7%	(4.79)	(176.83)	(9.77)	(360.37)
1701-1800	32,575	57,011,983	1,750	-2.1%	(2.93)	(95.37)	(5.97)	(194.35)
1801-1900	28,083	51,947,326	1,850	-0.7%	(1.07)	(30.13)	(2.19)	(61.41)
1901-1950	12,827	24,691,477	1,925	-0.1%	(0.15)	(1.95)	(0.31)	(3.98)
Total	560,291	726,657,292				(1,312)		(2,674)
1950-2000	12,575	24,839,718	1,975	0.5%	0.78	9.81	1.59	20.00
2001-2100	22,268	45,649,933	2,050	1.6%	2.60	58.00	5.31	118.20
2101-2200	20,138	43,270,919	2,149	2.6%	4.43	89.18	9.02	181.74
2201-2300	17,811	40,050,471	2,249	3.5%	6.25	111.26	12.73	226.75
2301-2400	16,145	37,930,330	2,349	4.3%	8.06	130.16	16.43	265.27
2401-2500	13,997	34,273,351	2,449	5.1%	9.87	138.11	20.11	281.47
2501-2600	13,023	33,193,713	2,549	5.8%	11.67	152.00	23.79	309.78
2601-2700	11,298	29,920,440	2,648	6.4%	13.47	152.17	27.45	310.11
2701-2800	10,262	28,210,880	2,749	7.0%	15.27	156.69	31.12	319.32
2801-2900	9,012	25,665,636	2,848	7.6%	17.06	153.70	34.76	313.24
2901-3000	8,245	24,289,074	2,946	8.1%	18.83	155.27	38.38	316.44
3001-3500	29,933	96,457,446	3,222	9.4%	23.95	716.76	48.80	1,460.74
3500+	40,453	181,925,271	4,497	12.1%	43.15	1745.48	87.93	3,557.25
Total	212,585	620,837,464				3,759		7,660
Grand Total	**1,253,262**	**1,619,853,829**				**4,182**		**8,523**
Total class usage (kWh)	1,619,854,622				Reduction	**0.26%**		**0.53%**

Company Proposal

Monthly Usage (kWh)	Proposed Increase	Short-run reduction in monthly usage, per bill (kWh)	Total first-year reduction, group (MWh)	Long-run reduction in monthly usage, per customer (kWh)	Total long-run annual reduction, group (MWh)
0-100	47.5%	1.92	50.89	3.91	103.72
101-200	34.8%	4.79	117.93	9.76	240.35
201-300	28.1%	6.02	207.36	12.26	422.59
301-400	23.9%	6.88	329.73	14.01	671.98
401-500	21.0%	7.66	468.83	15.61	955.46
501-600	19.0%	8.37	608.80	17.06	1,240.72
601-700	16.7%	8.65	683.37	17.62	1,392.68
701-800	15.1%	9.00	728.55	18.34	1,484.76
801-850	14.5%	9.47	381.29	19.29	777.06
Total			3,577		7,289
851-900	13.9%	9.66	382.94	19.69	780.42
901-1000	13.0%	9.80	742.32	19.96	1,512.83
1001-1100	12.3%	10.22	720.07	20.83	1,467.48
1101-1200	11.7%	10.67	692.71	21.74	1,411.73
1201-1300	11.2%	11.12	648.68	22.66	1,321.99
1301-1400	10.8%	11.57	605.28	23.58	1,233.55
1401-1500	10.5%	12.03	563.80	24.51	1,149.01
1501-1600	10.2%	12.49	519.59	25.46	1,058.92
1601-1700	9.9%	12.96	477.89	26.41	973.92
1701-1800	9.7%	13.43	437.48	27.37	891.57
1801-1900	9.5%	13.90	390.35	28.33	795.52
1901-1950	9.4%	14.32	183.74	29.19	374
Total			6,365		12,971
1950-2000	9.3%	14.56	183.13	29.68	373
2001-2100	9.2%	14.85	330.73	30.27	674.01
2101-2200	9.0%	15.32	308.51	31.22	628.74
2201-2300	8.9%	15.80	281.37	32.20	573.42
2301-2400	8.8%	16.28	262.86	33.18	535.71
2401-2500	8.7%	16.76	234.54	34.15	477.98
2501-2600	8.6%	17.24	224.49	35.13	457.51
2601-2700	8.5%	17.72	200.15	36.10	407.90
2701-2800	8.4%	18.20	186.79	37.09	380.67
2801-2900	8.3%	18.68	168.31	38.06	343.02
2901-3000	8.2%	19.15	157.86	39.02	321.71
3001-3500	8.0%	20.46	612.30	41.69	1,247.85
3500+	7.6%	27.13	1,097.52	55.29	2,236.73
Total			4,065		8,285
Grand Total			**14,190**		**28,919**
					2%
					1.79%

Staff Proposal revised with Company Revenue Requirement

Monthly Usage (kWh)	Proposed Increase	Short-run reduction in monthly usage, per bill (kWh)	Total first-year reduction, group (MWh)	Long-run reduction in monthly usage, per customer (kWh)	Total long-run annual reduction, group (MWh)
0-100	42.4%	1.71	45.41	3.48	92.55
101-200	32.7%	4.50	110.74	9.16	225.68
201-300	27.5%	5.90	203.37	12.03	414.47
301-400	24.3%	7.00	335.84	14.27	684.43
401-500	22.2%	8.06	493.55	16.43	1,005.84
501-600	20.6%	9.07	659.87	18.49	1,344.79
601-700	11.5%	5.96	471.00	12.15	959.89
701-800	5.2%	3.09	250.37	6.30	510.25
801-850	5.0%	3.24	130.55	6.61	266.07
Total			2,701		5,504
851-900	4.7%	3.30	130.67	6.72	266.30
901-1000	4.4%	3.32	251.68	6.77	512.93
1001-1100	4.1%	3.45	242.74	7.02	494.70
1101-1200	3.9%	3.58	232.31	7.29	473.44
1201-1300	3.8%	3.71	216.51	7.56	441.25
1301-1400	3.6%	3.84	201.16	7.84	409.96
1401-1500	3.5%	3.98	186.63	8.11	380.35
1501-1600	3.4%	4.12	171.37	8.40	349.25
1601-1700	3.3%	4.26	157.08	8.68	320.14
1701-1800	5.2%	7.22	235.32	14.72	479.57
1801-1900	7.0%	10.17	285.59	20.73	582.03
1901-1950	7.8%	11.79	151.26	24.03	308.26
Total			2,462		5,018
1950-2000	8.5%	13.28	166.93	27.05	340
2001-2100	9.9%	16.03	356.90	32.66	727.36
2101-2200	11.2%	18.93	381.19	38.58	776.85
2201-2300	12.3%	21.83	388.83	44.49	792.44
2301-2400	13.3%	24.73	399.34	50.41	813.84
2401-2500	14.3%	27.62	386.55	56.28	787.77
2501-2600	15.1%	30.50	397.24	62.16	809.57
2601-2700	16.0%	33.38	377.07	68.02	768.46
2701-2800	16.7%	36.26	372.10	73.90	758.33
2801-2900	17.4%	39.12	352.51	79.72	718.40
2901-3000	18.0%	41.95	345.91	85.50	704.95
3001-3500	19.7%	50.09	1,499.26	102.08	3,055.46
3500+	23.1%	82.10	3,321.31	167.32	6,768.74
Total			8,578		17,482
Grand Total			**13,908**		**28,344**
					1.75%

Exhibit No. JRS-22
Docket UE-140762 *et al.*
Witness: Joelle R. Steward

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

EXHIBIT OF JOELLE R. STEWARD

Residential Temperature Adjustments

November 2014

Residential Temperature Adjustments

	Residential Temperature Adjustments									
	UE-140762		UE-130043		UE-111190		UE-100749		UE-090205	
Month	MWh	($000)	MWh	($000)	MWh	($000)	MWh	($000)	MWh	($000)
January	(5,632)	$ (447)	(9,296)	$ (725)	18,571	$ 1,282	(9,836)	$ (650)	(21,009)	$ (1,289)
February	9,594	$ 761	5,918	$ 462	14,610	$ 1,008	(14,621)	$ (965)	8,564	$ 525
March	7,916	$ 628	(446)	$ (35)	5,752	$ 397	(12,617)	$ (833)	(7,614)	$ (467)
April	6,279	$ 498	4,853	$ 379	2,021	$ 139	(804)	$ (53)	(12,700)	$ (779)
May	(1,256)	$ (100)	1,850	$ 144	(510)	$ (35)	(2,949)	$ (195)	(2,343)	$ (144)
June	(2,594)	$ (206)	4,010	$ 318	2,901	$ 200	(2,432)	$ (161)	(1,779)	$ (109)
July	(26,896)	$ (2,135)	10,422	$ 813	(3,111)	$ (215)	(12,978)	$ (857)	(19,373)	$ (1,188)
August	(11,111)	$ (882)	(9,576)	$ (747)	(731)	$ (50)	(5,387)	$ (356)	1,335	$ 82
September	(5,872)	$ (466)	(2,381)	$ (186)	3,361	$ 232	(1,105)	$ (73)	1,530	$ 94
October	3,740	$ 297	5,914	$ 462	4,442	$ 307	(370)	$ (24)	(2,104)	$ (129)
November	(580)	$ (46)	(3,197)	$ (249)	(8,512)	$ (588)	3,099	$ 205	(5,420)	$ (333)
December	(18,837)	$ (1,538)	(10,856)	$ (847)	7,240	$ 500	(24,467)	$ (1,616)	(166)	$ (10)
Total	(45,248)	$ (3,635)	(2,784)	$ (212)	46,034	$ 3,177	(84,467)	$ (5,578)	(61,078)	$ (3,747)
Winter	(1,259)	($143)	(13,023)	($1,016)	39,682	$2,739	(59,246)	($3,912)	(38,344)	($2,352)
Summer	(43,989)	($3,492)	10,239	$804	6,353	$438	(25,221)	($1,665)	(22,733)	($1,395)

Confidential Per Protective Order in UTC Docket UE-140762
Exhibit No. JRS-23C
Docket UE-140762 *et al.*
Witness: Joelle R. Steward

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

REDACTED EXHIBIT OF JOELLE R. STEWARD

Energy Consumption Survey Response Comparison

November 2014

Washington survey response comparison between the average residential customer and the average residential customer with usage over 1,700 kWh in any given month

Notable Appliances	Avg WA	1700+
Electric furnace	[redacted]	
Gas furnace		
Heat pump heating		
Portable electric heat		
Baseboard heat		
Central AC		
Heat pump cooling		
Room AC		
Swamp coolers		
Electric water heater		
CFL/LED saturation		

Housing Type	Avg WA	1700+
Single family home	[redacted]	
Duplex/triplex		
Apartment building		
Townhouse/condo		
Manufactured home		

Age of Respondent	Avg WA	1700+
18 to 25	[redacted]	
26 to 35		
36 to 45		
46 to 55		
56 to 65		
Over 65		

Income of Respondent	Avg WA	1700+
Under $10,000	[redacted]	
$10,000 to $19,999		
$20,000 to $29,999		
$30,000 to $39,999		
$40,000 to $49,999		
$50,000 to $59,999		
$60,000 to $69,999		
$70,000 to $79,999		
$80,000 to $89,999		
$90,000 to $100,000		
$100,001 or more		
Prefer not to answer		

Average Square Footage	Avg WA	1700+
	[redacted]	

32) How do you review your bill?	Avg WA	1700+
1) You review the detailed items…	[redacted]	
2) You just look for the amount due…		
3) Your bill is paid automatically…		
4) You only look at the graph…		

33) How much is your average bill?	**Avg WA**	**1700+**
	[redacted]	

34) Are you aware of charging by kWh?	**Avg WA**	**1700+**
Yes	[redacted]	
No		

35) Do you keep track of your kWh?	**Avg WA**	**1700+**
Yes	[redacted]	
No		

36) How do you keep track of your kWh?	**Avg WA**	**1700+**
1) I review the bill	[redacted]	
2) I read the meter		
3) I review the bill and read the meter		
4) Neither		

37) How often do you read your meter?	**Avg WA**	**1700+**
Once a month	[redacted]	
Twice a month		
Three times a month		
Four times a month or more		
I don't read my electric meter		

38) How many kWh/month do you use?	**Avg WA**	**1700+**
1) Less than 600	[redacted]	
2) 601 to 1000		
3) More than 1000		
7) Don't know		

39) Are you aware of the tiered rate?	**Avg WA**	**1700+**
Yes	[redacted]	
No		

40) How aware are you of the levels/tiers?	**Avg WA**	**1700+**
4) Very aware	[redacted]	
3) Somewhat aware		
2) Not very aware		
1) Not at all aware		

41) Where do the pricing tiers kick in?	**Avg WA**	**1700+**
250 kWh	[redacted]	
600 kWh		
1000 kWh		
2000 kWh		
Don't know		

42) Were you aware of the tiers?	**Avg WA**	**1700+**
Yes	[redacted]	
No		

43) How easy are tiers to understand?	**Avg WA**	**1700+**
4) Very easy	[redacted]	
3) Somewhat easy		
2) Somewhat difficult		
1) Very difficult		

44) Have the tiers influenced your usage?	**Avg WA**	**1700+**
Yes	[redacted]	
Somewhat		
No		

45) Rather pay same rate for each kWh.	**Avg WA**	**1700+**
4) Strongly agree	[redacted]	
3) Somewhat agree		
2) Somewhat disagree		
1) Strongly disagree		

46) Rather increase basic charge, lower tie	**Avg WA**	**1700+**
4) Strongly agree	[redacted]	
3) Somewhat agree		
2) Somewhat disagree		
1) Strongly disagree		

47) How many residents in your home?	**Avg WA**	**1700+**
	[redacted]	

48) Home type?	**Avg WA**	**1700+**
Single family home	[redacted]	
Duplex, triplex, fourplex		
Apartment building		
Townhouse, row house, condo		
Manufactured home		
Other		

49) Has your home been remodeled?	**Avg WA**	**1700+**
Yes	[redacted]	
No		
Don't know		

50) Did you receive an incentive?	**Avg WA**	**1700+**
Yes	[redacted]	
No		
Don't know		

51) What year was your residence built?	**Avg WA**	**1700+**
	[redacted]	

51a) Do you generate solar/wind power?	**Avg WA**	**1700+**
Yes	[redacted]	
No		

52) Do you own or rent your home?	**Avg WA**	**1700+**
Own	[redacted]	
Rent		

53) Aware of our efficiency programs?	**Avg WA**	**1700+**
Yes	[redacted]	
No		

54) Ages of residents in your home	**Avg WA**	**1700+**
< 4 years old	[redacted]	
5 to 12 years old		
13 to 18 years old		
19 to 24 years old		
25 to 34 years old		
35 to 44 years old		
45 to 54 years old		
55 to 64 years old		
65+ years old		

55) How old are you?	**Avg WA**	**1700+**
18 to 25	[redacted]	
26 to 35		
36 to 45		
46 to 55		
56 to 65		
Over 65		

56) What is your income?	**Avg WA**	**1700+**
Under $10,000	[redacted]	
$10,000 to $19,999		
$20,000 to $29,999		
$30,000 to $39,999		
$40,000 to $49,999		
$50,000 to $59,999		
$60,000 to $69,999		
$70,000 to $79,999		
$80,000 to $89,999		
$90,000 to $100,000		
$100,001 or more		
Prefer not to answer		

57) Have you received financial assistance	**Avg WA**	**1700+**
Yes	[redacted]	
No		

Income Range of Survey Respondent	Count	Hit 1700	% of income group crosses 1700 kWh
Under $10,000	[redacted]		
$10,000 to $19,999			
$20,000 to $29,999			
$30,000 to $39,999			
$40,000 to $49,999			
$50,000 to $59,999			
$60,000 to $69,999			
$70,000 to $79,999			
$80,000 to $89,999			
$90,000 to $100,000			
$100,001 or more			
Prefer not to answer			
No answer			
All respondents			

Source: 2014 Washington Residential Consumption Survey