Rate Case Summary

Q4 2013
FINANCIAL UPDATE
QUARTERLY REPORT
OF THE U.S. SHAREHOLDER-OWNED
 ELECTRIC UTILITY INDUSTRY
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sents all U.S. investor-owned electric companies. Our members
provide electricity for 220 million Americans, operate in all 50
states and the District of Columbia, and directly employ more than
500,000 workers. With more than $85 billion in annual capital ex-
penditures, the electric power industry is responsible for millions
of additional jobs. Reliable, affordable, and sustainable electricity
powers the economy and enhances the lives of all Americans. EEI
has 70 international electric companies as Affiliate Members, and
250 industry suppliers and related organizations as Associate
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forums.

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EEI’s quarterly financial updates present industry trend analyses
and financial data covering 55 U.S. shareholder-owned electric
utility companies. These 55 companies include 49 electric utility
holding companies whose stocks are traded on major U.S. stock
exchanges and six electric utilities who are subsidiaries of non-
utility or foreign companies. Financial updates are published for
the following topics:

- Dividends
- Stock Performance
- Credit Ratings
- Construction
- Rate Case Summary
- SEC Financial Statements (Holding Companies)
- FERC Financial Statements (Regulated Utilities)
- Fuel

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financial and operating metrics. We look forward to serving as a
resource for member companies who wish to produce customized
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- Investor relations studies and presentations
- Internal company presentations
- Performance benchmarking
- Peer group analyses
- Annual and quarterly reports to shareholders

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industry data sets best address the needs of member companies
and the financial community. We welcome your comments,
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Future EEI Finance Meetings
EEI International Utility Conference
March 9-12, 2014
London Hilton on Park Lane
London, United Kingdom

For more information about EEI Finance Meetings,
please contact Debra Henry, (202) 508-5496, dhenry@eei.org
The 55 U.S. Shareholder-Owned Electric Utilities

The companies listed below all serve a regulated distribution territory. Other utilities, such as transmission provider ITC Holdings, are not shown below because they do not serve a regulated distribution territory. However, their financial information is included in relevant EEI data sets, such as transmission-related construction spending.

ALLETE, Inc. (ALE)
Alliant Energy Corporation (LNT)
Ameren Corporation (AEE)
American Electric Power Company, Inc. (AEP)
Avista Corporation (AVA)
Black Hills Corporation (BKH)
CenterPoint Energy, Inc. (CNP)
Cleco Corporation (CNL)
CMS Energy Corporation (CMS)
Consolidated Edison, Inc. (ED)
Dominion Resources, Inc. (D)

DPL, Inc.
DTE Energy Company (DTE)
Duke Energy Corporation (DUK)
Edison International (EIX)
El Paso Electric Company (EE)
Empire District Electric Company (EDE)

Energy Future Holdings Corp. (formerly TXU Corp.)

Entergy Corporation (ETR)
Exelon Corporation (EXC)
FirstEnergy Corp. (FE)
Great Plains Energy Incorporated (GXP)
Hawaiian Electric Industries, Inc. (HE)
Iberdrola USA
IDACORP, Inc. (IDA)
Integrys Energy Group, Inc. (TEG)


INVALCO Enterprises, Inc.
MDU Resources Group, Inc. (MDU)
MGE Energy, Inc. (MGEE)
Mid-American Energy Holdings Company
NextEra Energy, Inc. (NEE)


NiSource Inc. (NI)
Northeast Utilities (NU)
NorthWestern Corporation (NWE)


OGE Energy Corp. (OGE)
Otter Tail Corporation (OTTR)


Pepco Holdings, Inc. (POM)
PG&E Corporation (PCG)


Pinnacle West Capital Corporation (PNW)
PNM Resources, Inc. (PNM)
Portland General Electric Company (POR)
PPL Corporation (PPL)


Public Service Enterprise Group Inc. (PEG)
Puget Energy, Inc.
SCANA Corporation (SCG)
Sempra Energy (SRE)
Southern Company (SO)


TECO Energy, Inc. (TE)
UIL Holdings Corporation (UIL)


Unitil Corporation (UTL)
UNS Energy Corporation (UNS)


Vectren Corporation (VVC)
Westar Energy, Inc. (WR)


Wisconsin Energy Corporation (WEC)
Xcel Energy, Inc. (XEL)
Companies Listed by Category
(as of 12/31/12)

Please refer to the Quarterly Financial Updates webpage for previous years’ lists.

Given the diversity of utility holding company corporate strategies, no single company categorization approach will be useful for all EEI members and utility industry analysts. Nevertheless, we believe the following classification provides an informative framework for tracking financial trends and the capital markets’ response to business strategies as companies depart from the traditional regulated utility model.

<table>
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<th>Categorization</th>
<th>Description</th>
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<td>Regulated</td>
<td>0% to 80% of total assets are regulated</td>
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<td>Mostly Regulated</td>
<td>50% to 80% of total assets are regulated</td>
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<td>Diversified</td>
<td>Less than 50% of total assets are regulated</td>
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</table>

Categorization of the 49 publicly traded utility holding companies is based on year-end business segmentation data presented in 10Ks, supplemented by discussions with company IR departments. Categorization of the six non-publicly traded companies (shown in italics) is based on estimates derived from FERC Form 1 data and information provided by parent company IR departments.

The EEI Finance and Accounting Division continues to evaluate our approach to company categorization and business segmentation. In addition, we can produce customized categorization and peer group analyses in response to member company requests. We welcome comments, suggestions and feedback from EEI member companies and the financial community.

Regulated (36 of 55)

- ALLETE, Inc.
- Alliant Energy Corporation
- Ameren Corporation
- American Electric Power Company, Inc.
- Avista Corporation
- Black Hills Corporation
- Cleco Corporation
- CMS Energy Corporation
- Consolidated Edison, Inc.
- DPL, Inc.
- DTE Energy Company
- Duke Energy Corporation
- Edison International
- El Paso Electric Company
- Empire District Electric Company
- Entergy Corporation
- Great Plains Energy Incorporated
- Iberdrola USA
- IDACORP, Inc.
- Integrys Energy Group
- IPALCO Enterprises, Inc.
- Northeast Utilities
- NorthWestern Energy
- PG&E Corporation
- Pinnacle West Capital Corporation
- PNM Resources, Inc.
- Portland General Electric Company
- Puget Energy, Inc.
- Southern Company
- TECO Energy, Inc.
- UIL Holdings Corporation
- Unigas Corporation
- UNS Energy Corporation
- Westar Energy, Inc.
- Wisconsin Energy Corporation
- Xcel Energy, Inc.

Mostly Regulated (17 of 55)

- CenterPoint Energy, Inc.
- Dominion Resources, Inc.
- Exelon Corporation
- First Energy Corp.
- Hawaiian Electric Industries, Inc.
- MGE Energy, Inc.
- MidAmerican Energy Holdings
- NextEra Energy, Inc.
- NiSource Inc.
- OGE Energy Corp.
- Otter Tail Corporation
- Pepco Holdings, Inc.
- PPL Corporation
- Public Service Enterprise Group, Inc.
- SCANA Corporation
- Sempra Energy
- Vectren Corporation
- MDU Resources Group, Inc.

Diversified (2 of 55)

- Energy Future Holdings
- MDU Resources Group, Inc.

Note: Based on assets at 12/31/12
HIGHLIGHTS

- Shareholder-owned electric utilities filed seven rate cases in Q4 and 46 in 2013, for the lowest number of annual filings since 2009. However, 24 cases were decided in Q4 and utilities rarely file a new case with one still in progress. We expect the number of filings to remain high, reflecting the industry’s ongoing elevated capital investment.

- The average allowed ROE in Q4, at 9.90%, was near the bottom of a long trend of declining allowed ROEs caused by falling interest rates and, in recent years, commissions’ concerns about keeping rates low in economically challenging times.

- Capital investment, recovery of O&M, trackers and riders, storm cost recovery and weak power demand were primary reasons for Q4 and full-year 2013 case filings.

- The average regulatory lag for 2013 was 8.42 months, lower than in recent years but not likely indicative of commission efforts to reduce lag.

COMMENTARY

Shareholder-owned electric utilities filed seven new rate cases in the fourth quarter of 2013 and a total of 46 for the full year, the lowest number of annual filings since 2009. When combined with the four cases filed in the third quarter, the slow pace of filings in the year’s second half might suggest a reversal in the trend of escalating rate case activity since the year 2000. However, 24 cases were decided in Q4 and utilities rarely file a case while another is still in progress. We expect the number of filings to remain high, reflecting the industry’s ongoing construction cycle driven by the need to replace and upgrade infrastructure and reduce the environmental impact of power generation.

The primary reason for the fourth quarter’s filings was capital investment, the most frequently cited driver of rate cases in recent years. Another prevalent factor in Q4 was storm recovery. Capital investment was also the major driver of filings in full-year 2013, as it has been each year since the
initiation of this report series. Utilities’ efforts to implement adjustment mechanisms, such as trackers and riders, was the second major driver of filings in 2013, edging out recovery of rising operation and maintenance (O&M) expenses. Trackers and O&M recovery have also been regular causes of filings in recent years. Finally, storm cost recovery was cited in many filings in 2013, as were efforts to recover for revenue shortfalls caused by low demand growth in the industry.

The average allowed ROE in Q4, at 9.90%, was the third lowest quarterly total in recent decades and near the bottom of a long trend of declining allowed ROEs caused by falling interest rates and, in recent years, commissions’ concerns about rate increases in economically challenging times.

The average allowed ROE for 2013 was 10.02%, the lowest in our decades of data. The average allowed ROE for 2012 was 10.15%. The last four years have each set successive record lows.

The average requested ROE in Q4 was also a record low, at 10.24%, and for similar reasons as the decline in allowed ROE. The average requested ROE for 2013 was 10.46%, a record low and below 2012’s 10.72%, and the fourth in a series of consecutive annual record lows.

Average regulatory lag in Q4, at 8.14 months, was a bit lower than the average regulatory lag that has held for the past decade (at around ten months). Based on a review of rate case decisions, the slightly lower number does not seem to indicate attempts by commissions to decrease lag during a time of heavy industry investment. Around the turn of the century, during industry restructuring, regulatory lag was more volatile and generally higher. The average regulatory lag for 2013 was 8.42 months, lower than in recent years but not likely suggestive of commission efforts to reduce lag.

Filed Cases in Q4

**Storm and Other Reliability Issues**

In addition to capital investment (the usual driver of rate case filings), spending on storm preparedness and other reliability efforts was a major driver of filings in Q4. Rockland Electric in New Jersey filed to recover costs from three storms: $11 million of the company’s requested $19.3 million increase was for Hurricane Irene, a 2011 snow storm, and Superstorm Sandy. The $11 million includes $2.2 million for increased storm reserves and $1 million for storm hardening. The company also filed for a surcharge for recovery of future storm-hardening projects.

The primary driver of Northern States Power’s Q4 filing in Minnesota was increased capital investment, in part to provide customers with increased reliability by lengthening the life of the company’s nuclear plants and strengthening the grid. Similarly, Potomac Electric Power in Maryland hopes to get recovery for $240 million spent on infrastructure enhancements, which have allowed the company to achieve reliability metrics required by the commission.

**Northern States Power – Minnesota**

NSP proposed a “rate modernization plan” that would accelerate from eight years to three years the amortization of transmission, distribution and generation plant depreciation reserve surplus and use funds from a settlement with the Department of Energy to mitigate the impact on ratepayers.
## VI. Rate Case Data: From Tables I-V

**U.S. Shareholder-Owned Electric Utilities**

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Number of Rate Cases Filed</th>
<th>Average Awarded ROE</th>
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<th>Average 10-Year Treasury Yield</th>
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The company also proposed a weather-normalized revenue decoupling mechanism for residential and small commercial customers and interim rate treatment for a coal plant that is returning to service after a technical problem.

**Miscellaneous**

Potomac Electric Power in Maryland filed in part because the company’s earned ROE is only 6.69% (allowed ROE is 9.36%). Bangor Hydro Electric and Maine Public Service filed together. The companies merged into a single entity — Emera Maine — at the end of 2013, after the filing. They hope to recover costs relating to a new customer information system and vegetation management. Kansas City Power & Light in Kansas filed an “abbreviated” case; this is allowed by law in Kansas when the filing is made within 12 months of a rate case order and reflects “all the regulatory procedures, principles, and rate of return [parameters] established by the Commission.”

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### U.S. Shareholder-Owned Electric Utilities

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<thead>
<tr>
<th>Quarter</th>
<th>Number of Rate Cases Filed</th>
<th>Average Requested Rate of Return (ROE)</th>
<th>Average Awarded ROE</th>
<th>10-Year Treasury Yield</th>
<th>Average Regulatory Lag</th>
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NA = Not available

Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department
Filed Cases in 2013

Storm Cost Recovery

Storm cost recovery figured prominently in rate case filings in 2013. United Illuminating filed in Connecticut in part to recover costs for storms since 2008. The company claimed $52 million in unfunded storm costs and proposed to draw on the customers’ share of the company’s earnings sharing mechanism for funding. The company proposed to recover $8.7 million of storm costs annually to amortize storm expense.

As part of Baltimore Gas and Electric’s filing in Maryland the company proposed to implement an electric reliability investment (ERI) initiative and an associated tracker mechanism. Both are based on guidelines established as part of the commission’s review of Maryland utilities’ reliability performance and a governor’s task force recommendation following a derecho storm. The ERI includes measures to be completed between 2014 and 2018 at an estimated cost of $136 million and is expected to improve the company’s reliability by 10% compared to its average performance between 2010 and 2012.

Fitchburg Gas & Electric Light in Massachusetts filed to recover storm-related expenses and costs of reliability improvement, vegetation management and related enhancements. In addition, the company asked to implement a storm cost recovery factor.

Earned Return

Several companies filed cases in 2013 as a result of under-earning their authorized return, which can happen when regulatory lag prevents the company from catching up with rising expenses. Potomac Electric Power in its Washington, D.C. filing said it earned less than half of its authorized 9.5% ROE during the test year. Virginia Electric & Power said that its return had been reduced by 50 basis points by the retirement of six coal plants and by storm expenses. Baltimore Gas and Electric said that it expected to earn a 5.68% overall return for the year ending 7/31/2013.

ROE: Decreases for Decoupling

Electric utilities during 2013 sought to eliminate ROE decreases imposed by commissions because the companies have decoupling programs. The commissions argued that decoupling decreases risk and the utility should therefore be awarded a lower ROE. The 10.25% ROE that Potomac Electric Power filed for in D.C. in 2013 did not reflect a 50-basis-point downward adjustment to reflect the company’s decoupling mechanism. The company said the downward adjustment did not reflect current market conditions and was contrary to the vast majority of cases for decoupled utilities. Similarly, Delmarva Power & Light in its Maryland filing sought to dispense with the 50-basis-point reduction because it did not reflect current market conditions.

Low Growth


Westar Kansas

Westar filed in Kansas for recovery of incremental costs, including construction work-in-progress, for an emissions control project at a coal plant. Among the many goals Westar hopes to achieve is a reduction in cross-class subsidies, an increase in the fixed monthly residential customer charge from $9 to $13, and an increase in the small general customer charge from $19 to $20.

Decided Cases in Q4

Monongahela Power West Virginia

In Q4, the West Virginia Commission approved a settlement for Monongahela Power that transfers generation assets to Monongahela from affiliated companies and implements a surcharge for generation recovery. The settlement also requires the company to hire 50 employees from West Virginia and contribute $500,000 over five years to each of the following: a low income assistance program, a weatherization program and a public school energy efficiency program. The settlement also requires the company to achieve, as part of an energy efficiency plan, 0.5% in energy savings by the year ending May 31, 2018 relative to 2013 delivery sales. Monongahela Power can recover the cost of the energy efficiency plan in rates, but the parties could not agree to recovery of lost revenue associated with the related decrease in sales.

Virginia Electric & Power

In Q4, the Virginia commission decided Virginia Electric & Power’s legally mandated biennial earnings review case. Virginia state law requires that the commission determine a “fair” ROE based on the market cost of equity, a state-law-determined-peer-group ROE floor, and adjust for management performance, if necessary. Based on this formula, the company requested an ROE of 11.5%. The commission allowed 10%. The commission determined that “a market cost of equity of 10% fairly represents the actual cost of equity in capital markets for companies comparable in risk to Dominion seeking to attract equity capital. . . . We conclude that a market cost of equity of 10% fairly represents the actual cost of equity in capital markets for companies comparable in risk to Dominion seeking to attract equity capital.” The commission proposed a 55.624% equity component in its capital structure. The commission said the proposed equity component “is neither reasonable or prudent for the purpose of setting rates [because it] 1) significantly exceeds the average equity ratio of its peers (including peers con-
structing nuclear plants); 2) is higher than necessary in order for [the company] to maintain reasonable credit ratings; 3) exceeds the company’s own financial targets; and, 4) is higher than necessary for Dominion to raise capital on reasonable terms to its planned capital expenditures.” The commission approved a 50% equity ratio. The commission also excluded $2.3 million in incentive compensation costs.

**PaciﬁCorp Washington**

In Q4, the Washington state commission rejected PaciﬁCorp’s proposed power cost adjustment mechanism (PCAM), saying that the company failed “to demonstrate sufﬁcient power cost variability to warrant approval for such a mechanism” and that the company did not design the mechanism in accordance with prior commission directives. The commission said “a properly designed PCAM includes dead bands and sharing bands so that the Company continues to bear some risk of under-recovery, and some opportunity to beneﬁt from savings achieved via power cost management practices.”

**Baltimore Gas and Electric (BGE)**

The Maryland commission approved ﬁve of eight proposals made by the company in relation to its Electric Reliability Investment initiative (ERI). The company developed this initiative (see also 2013 Filings above) in response to guidelines established in the commission’s review of Maryland utilities’ performance following a derecho storm in 2012. The company proposed an annual surcharge to recover costs associated with the initiative and crafted the surcharge to be consistent with recommendations by the Maryland Governor’s Grid Resiliency Task Force. The company’s eight proposals were: 1) expand the poorest performing feeder replacement program, 2) expand vegetation management, 3) improve the customer average interruption duration index (CAIDI), 4) expand recloser deployment on 13 kV distribution feeders, 5) expand recloser deployment on 34 kV lines, 6) diversify routing of 34 kV supply circuits, 7) implement selective undergrounding, and 8) improve substation reliability performance. The total cost for the initiative would have been $136 million between 2014 and 2018. Each surcharge would project costs through the coming year and true up at the end of the year. The commission approved 1, 4, 5, 6 and half of what the company proposed for 7. The commission said, “We respectfully disagree with those parties advocating that we wait until new [reliability] regulations are adopted, effective in 2016 and beyond, as the need to improve reliability is immediate and exigent . . . what the Commission expects to see at the end of the ﬁve-year period, is a total improvement of over 12% in SAIDI [System Average Interruption Duration Index] and at least 3.7% in SAIFI [System Average Interruption Frequency Index].”

Two commissioners dissented on recovering ERI through a surcharge, saying that “approval of a surcharge is contrary to the precedent established by this Commission as well as sound regulatory policy. The surcharge will unfairly shift risks that are properly borne by the company shareholders to ratepayers, based on a multi-year forecast of plant that has not been demonstrated to be used or useful and estimated expenses that are not known and measurable. . . . we find the likelihood of ‘claw back’ of revenue of a future prudence review to be implausible.”

BGE had also requested a 10.5% ROE, but the commission awarded 9.75%, as in BGE’s previous case. The commission said that in the previous case it “determined that BGE was a low-risk investment based upon evidence it presented and past-market performance as a monopoly provider of electric and gas distribution service, its lack of ownership of any generating facilities, and its stable service territory with a BSA [decoupling] mechanism. Additionally, we found that the low interest rate environment that existed at the time . . . provided BGE with ample opportunity to obtain necessary capital at reasonable rates. The question in this case, therefore, . . . is, what has changed in less than one year . . . that now might justify a different return. BGE has not demonstrated any significant changes in the economic environment faced by the company.” The commission noted that it had not adjusted the ROE downward as a result of its partial approval of the ERI.

The commission rejected a non-ERI adjustment for reliability-related projects, saying “such tools must be carefully constructed to insure ratepayer interests are protected in advance and that investments are cost effective. . . . we only allow recovery of post-test-year spending in rate base, if the plant investment is safety or reliability related, only if the amounts represent actual spending, and only if the amounts are known and measurable.”

BGE also proposed to recover its major storm restoration expense over a three-year period, rather than the five-year period typically approved by the commission, because of the magnitude and frequency of major storms in recent years. The commission rejected the change, saying the company “has provided no demonstrable scientiﬁc evidence that the same frequency of major storms would continue in Maryland on any predictable basis, and that the five-year recovery period would not be sufﬁcient. . . . in 2013 there have been no major storms.”

**Miscellaneous**

In Gulf Power’s case in Florida, the commission approved a settlement that authorizes an adjustment mechanism that permits the company to raise allowed ROE by 25 basis points if the 30-year U.S. Treasury bond yield increases by an average of 75 basis points above 3.7947% for a six-month period. In Ameren Illinois’s case associated with the com-
pany’s formula rate plan, the commission reduced the company’s revenue requirement to account for revenue the company received as a result of its selling “vacated microwave frequencies” to telecommunication companies. The company argued that these frequencies had been used to transmit transmission data, and consequently were FERC jurisdictional. In Sierra Pacific’s case in Nevada, the commission granted the company’s demand side management investments a 500-basis-point return above authorized ROE and combined-cycle natural gas generation a 150-basis-point bonus return. In Upper Peninsula Power’s case in Michigan, a settlement requires the company to spend $3.2 million on tree trimming and clear at least 1,760 miles of line or refund the difference to customers.

Decided Cases in 2013

ROE
In Kansas City Power & Light’s subsidiaries’ cases in Missouri, the companies originally requested a 10.4% ROE, later modified to 10.3%. The commission authorized 9.7%, in part because of “the downward trend in national averages of other state commissions’ ROE awards, the continuing downward pressure on interest rates nationally, [and] the slower-than average recovery in Missouri.”

In Michigan Power’s case in Indiana, the commission awarded a 10.2% ROE as the mid-point of all the parties’ recommendations, additionally finding that changes to the off-system sales (OSS) margin sharing mechanism and establishment of a storm reserve reduced the company’s earning risk. The off-system sales mechanism was changed so that all variations are shared equally by customers and shareholders; the previous mechanism only shared amounts above a certain embedded amount with shareholders. The commission justified the different sharing mechanism as warranted by “market dynamics” and said that “sharing only the amount of sales in excess of the [embedded] amount and not any shortfalls does not fairly align the risk and reward of OSS sales between the company and ratepayers.” The company had proposed a “fair value increment” to the revenue requirement to support its “continued financial resilience.” This increment was calculated by applying an inflation-adjusted long-term Treasury bond yield to the difference between the company’s fair value rate base and net original cost rate base. The company said that the commission’s approval of the increment would “provide a clear signal that the Commission is willing to use the regulatory tools at its disposal to support [the company’s] efforts to maintain investment-grade [credit] ratings and improve its credit standing by improving its ability to earn its allowed return.” The commission concluded that the increment “artificially inflates the company’s rates by arbitrarily increasing the amount of revenues [the company] is authorized to collect above that already calculated to provide a reasonable opportunity to earn its authorized return.”

In Baltimore Gas and Electric’s case in Maryland, the commission awarded the company a 9.75% ROE that reflected a downward adjustment of 50 basis points because the company has a decoupling mechanism. (For additional discussion of this issue for BGE, see Decided Cases in Q4 above.) BGE had argued that such an adjustment was not necessary because all the companies in the proxy group either had decoupling mechanisms or other revenue recovery mechanisms. The commission commented that, because another recent order prevented utilities from recovering lost revenues from storms through the decoupling mechanism, “a strict basis point reduction of 50 points may no longer be warranted,” but the company’s decoupling mechanism is “a ‘very good’ decoupling mechanism, better than almost all the others in any of the experts’ proxy groups, which serves to limit the risk, and therefore the appropriate ROE, for BGE.”

Indiana-Michigan Power (IM) Indiana
IM had proposed to include $6.2 million of storm restoration costs in its revenue requirement using a three-year average of these costs. The commission instead mandated a five-year average, at $4.2 million, but also allowed the company to implement a tracking mechanism for storm costs. The commission said “at times the cost of [storm] restoration may greatly exceed the amount of expense included in [the company’s] revenue requirement. . . . that risk is traditionally borne by shareholders. In the past, the Commission has allowed a utility to seek recovery of extraordinary storm restoration expenses through a separate proceeding, but only when the storm at issue was a worst-case scenario. As we have recently seen, these stand-alone cases are often heavily litigated and highly contentious. Of course, the opposite situation also occurs, where the costs of storm restoration may be substantially less than the amount of the expense included in [the company’s] revenue requirement. . . . the accounting [treatment] proposed by the Company . . . addresses both of these situations.”

Baltimore Gas and Electric (BGE)
In the first of two cases decided for BGE during 2013 (for more on the second case see Decided Cases in Q4 above), the company argued that its use of a historical test year, along with rising costs, prevented it from earning its authorized return. Additionally, the company had planned more than $3 billion in capital expenditures over the next five years. As a result, BGE sought to include estimated post-test-year investments in rate base. BGE said the estimated costs meet the known and measurable test because the company is required to spend 95% of its planned capital expenditures and operation and maintenance expenses in 2012 and 2013 as a condition of its merger with Exelon. BGE also said it
has shown a pattern of investment in safety and reliability and thus can easily estimate these costs. However, the commission found the proposal to include estimated post-test-year investments in rate base did not meet the known and measureable test, because it was “simply an estimate” and lacked sufficient support. The commission found the safety and reliability investment not used and useful or known and measureable and that “by the Company’s own admission, estimates, forecasts, and budgets can prove unreliable.”

**Duke Energy Ohio**
The Ohio commission authorized a settlement that grants Duke an $11 million vegetation management expense, the same amount the company spent in the test year, and a $4.4 million baseline expense for storms, but disallowed the company’s requested storm deferral and tracking mechanism and any attempt to recover incremental expenses for 2012 storms. The company can request deferral of incremental storm costs after 2012. The settlement does not allow Duke’s proposed rider to recover costs of facility relocation associated with mass transportation projects. Duke had claimed that, under pre-existing rates, it would earn a return of 4.79% on rate base. The commission said that such a rate of return is “insufficient to provide [the company] with reasonable compensation for the service it renders to customers.”

**San Diego Gas & Electric (SDG&E)**
The California commission allowed SDG&E attrition rate increases for 2013-2015 based on changes in the Consumer Price Index-Urban, with some modifications. The commission authorized rate increases of 2.65% for 2013 and 2.75% for both 2014 and 2015. The commission also extended, subject to a $5 million deductible, the “Z-factor” mechanism that allows utilities to request recovery, under certain circumstances, for significant, unforeseen expenses between rate cases. The commission also allowed the company recovery of costs associated with the San Onofre Nuclear Generating Station, subject to refund pending a reasonableness review.

**Maui Electric (MECO)**
MECO entered into a settlement that would have authorized a 10% ROE, but the Hawaii commission reduced the ROE to 9%, because a 10% ROE would have fallen out of the 9% to 9.75% range proposed by the Division of Consumer Advocacy, one of the parties to the settlement. In addition, the commission said that half of the 100-basis-point adjustment was due, in part, to “updated economic and financial market conditions.” The commission said that the second half of the adjustment reflected “apparent system inefficiencies which negatively impact MECO’s customers. . . . [The company] appears to have failed to adequately and sufficiently plan for and implement the necessary modifications to its existing operations to accept a more appropriate level of wind energy generation made available to MECO, negatively impacting ratepayers through higher electricity rates.” The commission said the order is intended to serve notice to MECO and other Hawaiian Electric utilities. The commission said the utilities “appear to lack movement to a sustainable business model to address technological advancements and increasing customer expectations. The commission observes that some mainland electric utilities have begun to define, articulate and implement the vision for the ‘electric utility of the future.’ Without such a long-term, customer-focused business strategy, it is difficult to ascertain whether [the Hawaiian Electric utilities] increasing capital investments are strategic investments or simply a series of unrelated capital projects that effectively expand utility rate base and increase profits but [appear] to provide little or limited long-term customer value.”

**Miscellaneous**
The Kansas City Power & Light utilities proposed to modestly increase customer charges, but the commission rejected the increases, saying, “Because volumetric charges are more within the customer’s control to consume or conserve, the volumetric rate is the more appropriate to increase.” In Tucson Electric Power’s case, the commission did authorize increases in customer charges, including an increase in the residential customer charge from $7 to $10, saying the $10 charge was “a small part of the overall average bill of over $84” and well less than the $56 average monthly fixed costs per residential customer. In Potomac Electric Power’s case in Maryland the commission denied the company recovery of $23.4 million in advanced metering infrastructure investment, saying that Pepco has yet to demonstrate that this investment is cost-effective. In Northern States Power’s case in Minnesota, the increase allowed by the commission was less than the interim rates the company had implemented, and consequently the company owed customers a refund. In calculating the refund, the commission departed from its usual practice of using the average prime rate (3.25% in this case) in calculating the interest due customers, and instead used the overall rate of return (7.45%). In United Illuminating’s case, the Connecticut commission rejected a 36% equity ratio capital structure proposed for the company by the Connecticut Industrial Energy Consumers (compared to a 50% ratio proposed by the company), saying “imposing such an extreme change . . . to the company’s ratemaking capitalization mix may be disruptive to its financial stability and credit rating. . . . [We] will continue to monitor electric utility industry practices with regard to capitalization mix and will make changes to the ratemaking capital structure should industry standards change significantly.”